NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2019021127	MOD-032-1	R2	Cedar Falls Utilities (CFU)	NCR00969	09/28/2017	09/21/2018	Self-Certification	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 14, 2018, CFU submitted a Self-Certification stating that, as a Resource Planner and Transmission Owner, it was in noncompliance with MOD-032-1 R2. In the Self Certification response, CFU indicated that it failed to notify the Planning Coordinator (PC) that it did not have any model data changes for the 2018 model series according to the data requirements and reporting procedures developed by its PC. CFU received a data request from its PC for the 2018 model building series on August 29, 2017. CFU’s responses were due September 28, 2017. The cause of the noncompliance was that CFU’s process for completing the MOD-032-1 R2 data request was deficient as it did not have controls to ensure the PC would be notified if CFU model data had not changed since the previous model building series. This noncompliance began on September 28, 2017, the required due date for model data submissions per the PC data request, and ended on September 21, 2018, when CFU provided a response to its PC for the 2019 model building series.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Per CFU, there were no changes to the CFU data submission for the 2018 model series, therefore, the failure to notify the PC was administrative in nature. Additionally, CFU owns 12 miles of 161-kV transmission line, including two 161-kV interconnections with a neighboring TO. Model data issues for a transmission system of this size pose limited risk to the reliability of the BPS, as indicated by the Transmission Portfolio risk factor in the CFU Internal Risk Assessment, which meets the low risk criteria. No harm is known to have occurred. CFU has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, CFU: 1) provided a data request response to its PC for the 2019 model building series; 2) added multiple individuals from its internal compliance team PC to the data request distribution list; and 3) will initiate correspondence with its neighboring TO, to either submit model data on its behalf, or to confirm with the PC that there are no changes to the CFU model data, when data request are received.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2019020998	MOD-025-2	R1	Hennepin County, MN (HCMN)	NCR00381	07/01/2016	12/21/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 23, 2019, HCMN submitted a Self-Report stating that as a Generator Owner, it was in noncompliance with MOD-025-2 R1. HCMN reported that it had not verified and submitted the Real Power capability of its applicable generation Facility by the required date (July 1, 2016) in the MOD-025-2 R2 phased implementation plan. At the time of noncompliance, HCMN was relying on a third-party contractor to perform and submit the Real and Reactive Power capability verifications. The cause of the noncompliance was that HCMN failed to ensure that its contractor performed and submitted the Real and Reactive Power capability verifications prior to transitioning the operation of its generator facility to its current Generator Operator. This noncompliance began on July 1, 2016, when the standard became mandatory and enforceable, and ended on December 21, 2018, when HCMN conducted the staged Real Power verifications and submitted a completed Attachment 2 to its Transmission Planner (TP).
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Per HCMN's Inherent Risk Assessment, its generator Facility has a nameplate capability of 54 MVA. Therefore, a failure to validate the Real and Reactive Power capability for units of this size would have limited impact on the reliability to the BPS. HCMN's generating Facility meets the low risk criteria of the Largest Generator Facility and Total Generation Capacity ERO risk factors. Additionally, the HCMN generator is not identified as a Blackstart Resource. No harm is known to have occurred. HCMN does not have any relevant compliance history.
Mitigation	To mitigate this noncompliance, HCMN: 1) conducted the Real and Reactive Power verification stated tests; 2) submitted the results of the test to its TP; and 3) scheduled subsequent verification testing required by MOD-025-2 in its asset management system to prompt alarms and reminders to submit verified data in advance of required future reverification due dates.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2019020999	MOD-025-2	R2	Hennepin County, MN (HCMN)	NCR00381	07/01/2016	12/21/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 23, 2019, HCMN submitted a Self-Report stating that as a Generator Owner, it was in noncompliance with MOD-025-2 R2. HCMN reported that it had not verified and submitted the Reactive Power capability of its applicable generation Facility by the required date (July 1, 2016) in the MOD-025-2 R2 phased implementation plan. At the time of noncompliance, HCMN was relying on a third-party contractor to perform and submit the Real and Reactive Power capability verifications. The cause of the noncompliance was that HCMN failed to ensure that its contractor performed and submitted the Real and Reactive Power capability verifications prior to transitioning the operation of its generator facility to its current Generator Operator. The noncompliance began on July 1, 2016, when the standard became mandatory and enforceable, and ended on December 21, 2018, when HCMN conducted the staged verifications and submitted a completed Attachment 2 to its Transmission Planner (TP).
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Per an HCMN Inherent Risk Assessment, the HCMN generator Facility has a nameplate capability of 54 MVA. Therefore, a failure to validate the Real and Reactive Power capability for units of this size would have limited impacted on the reliability of the BPS. HCMN's generating Facility meets the low risk criteria of the Largest Generator Facility and Total Generation Capacity ERO risk factors. Additionally, the HCMN generator is not identified as a Blackstart Resource. No harm is known to have occurred. HCMN does not have any relevant compliance history.
Mitigation	To mitigate this noncompliance, HCMN: 1) conducted the Real and Reactive power verification staged tests; 2) submitted the results of the test to its TP; and 2) scheduled subsequent verification testing required by MOD-025-2 in its asset management system to prompt alarms and reminders to submit verified data in advance of required future reverification due dates.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020448	VAR-002-4	R1	Montana-Dakota Utilities Company (MDU)	NCR01015	04/01/2016	08/15/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 21, 2018, MDU submitted a Self-Report stating that as a Generator Operator, it was in noncompliance with VAR-002-4 R1. MDU is also registered in the Western Electricity Coordinating Council Region under the same name and NCR ID; both are monitored under the Coordinated Oversight Program and processed by MRO. MDU reported that it failed to operate its Lewis and Clark Units 2 & 3 (Units) in the automatic voltage control mode as directed by the MDU Transmission Operator (TOP). MDU discovered this noncompliance during a review of EMS tags on July 28, 2018 and determined that a "scan inhibit" had been placed on the AVR status EMS point for the Units. Inhibiting scanning of this AVR status point limited the MDU system operator's awareness of the status of the AVRs. While investigating the cause of the scan inhibit, MDU discovered that the AVRs for both Units were in the power factor control mode and not the automatic voltage control mode. The cause of the noncompliance was that at commissioning, manufacturer documentation for the Units indicated that for normal operations the AVR should be placed in the power factor control mode. There was confusion as to what control mode should be utilized for these units, and MDU failed to communicate the issue to the TOP, who believed that the units were operating in automatic voltage control mode. The noncompliance began on April 1, 2016, when the units first became operational and were set to the power factor control mode, and ended on August 15, 2018, when the control modes were changed to voltage control.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The Units have nameplate ratings of 11.7 MVA each, for a total of 23.4 MVA. Such capacity would have limited impact on the ability to control system voltage. Further, per MDU the Units are peaking units and are not relied upon for voltage control in the Eastern Interconnection. Additionally, MDU reviewed historic operations for the two Units and determined that system voltages were maintained at the TOP's prescribed level in all but one dispatch period. On that particular day, outages to the 115 kV transmission system in the area caused system voltage to drop below 1 per unit (P.U.), but system voltage remained above the 0.98 P.U. threshold where generator action to increase VAR output is required, per the MDU Voltage and Reactive Control Procedure. Lastly, MDU reviewed the AVR control modes and EMS AVR status indications on its remaining units, and confirmed that the issue was limited to the Lewis and Clark Units 2 & 3. No harm is known to have occurred. MDU has no relevant compliance history.
Mitigation	To mitigate this noncompliance, the Entity: 1) tested the Units and changed the voltage control modes; 2) updated the MDU Voltage and Reactive Control Procedure to reduce ambiguity surrounding the requirement to operate in the automatic voltage control mode; 3) provided training to the Power Production group on the updated Voltage and Reactive Control procedure, including actions to take when a unit cannot comply with the TOP's instructions; 4) restored and verified functionality for the EMS AVR status point for the Units; and 5) provided training to its System Operators to reinforce the monitoring and verification of generator AVR status, with instructions for remediating abnormal status or indications.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2019021536	PRC-024-2	R4	Minnesota Power (Allete, Inc.) (MP)	NCR00674	04/24/2018	11/20/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On April 10, 2019, MP submitted a Self-Log stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R4. MP reported that it did not respond to a written request, from its Planning Coordinator (PC) (Midcontinent Independent Systems Operator), within 60 calendar days as required by PRC-024-2 R4 for its Bulk Electric System (BES) Generation Facilities settings associated with PRC-024 R1 and R2. The cause of the noncompliance was due to that MP did not have sufficient communications processes in place to route the request for PRC-024 data to the appropriate MP Subject Matter Expert (SME) in order to ensure that a response would be provided within the 60 days as specified in the standard when the PC implemented a new process for requesting the data. The noncompliance began on April 24, 2018, when MP failed to respond to its PC's request within 60 days, and ended on November 20, 2018, when the information was sent to its PC.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The voltage settings are used only in long term planning studies and there was no immediate harm to the BPS due to the delay in providing the modeling information. Additionally, MP previously provided the requested R1 and R2 information to its PC on December 8, 2017, and the settings had not changed since that submission. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, MP: 1) provided its PC with the requested information; 2) added its Compliance Department's email address to various PC email groups to ensure the department and SMEs receive the requests; 3) created an email template to be sent to the applicable MP SMEs along with any data requests to ensure requests are being reviewed for reference to NERC Standards; and 4) added resources to ensure that the requests are reaching more individuals hence ensuring that it is providing the applicable generator protection trip settings associated with PRC-024-2, R1 and R2 to the its PC within 60 calendar days of the receipt of a written request.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020586	TOP-002-4	R7	Northern States Power (Xcel Energy) (NSP)	NCR01020	06/12/2017	06/19/2017	Self-Certification	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 28, 2018, Public Service Company of Colorado (PSCO), a Coordinated Oversight Program participant, submitted a Self-Certification stating that, as a Balancing Authority, it was in noncompliance with TOP-002-4 R7. Northern States Power (NSP), PSCO (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program and processed under Northern States Power (Xcel Energy) (NSP) (NCR01020). The noncompliance occurred in the PSCO operating area. Xcel Energy reported that during the period of noncompliance, the Outage Coordination engineer responsible for submitting the Operating Plan to the RC was out of the office. The backup engineer received and reviewed the Operating Plan each day, but did not submit the plan to the Reliability Coordinator (RC). The cause of the noncompliance was that Xcel Energy failed to have sufficient controls in place to ensure the Operating Plan would continue to be submitted to the RC while the primary responsible engineer was out of the office. The noncompliance began on June 12, 2017, when Xcel Energy discovered that it failed to provide its Operating Plan for next-day operations to its RC, and ended on June 19, 2017, when they resumed providing the Operating Plan to its RC.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Xcel Energy determined the risk was minimal as its un-submitted Operating Plans identified no concerns in expected generation resource commitment and dispatch, interchange scheduling, demand patterns, or capacity and energy reserve requirements. Also, despite not providing the Operating Plans, a regular daily (Monday-Friday) coordination call was conducted with the RC to discuss transmission and generation conditions and plans. The issue was limited to a one week time period while the primary Outage Coordination engineer was out of the office. The Self-Certification response evidence indicates this was not a systemic or reoccurring issue. No harm was known to have occurred. Xcel Energy has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, Xcel Energy: 1) resumed submitting the Operating Plans to the RC; 2) enhanced its procedures for submitting the Operating Plan to the RC to include a checklist or similar guide for the individual responsible for performing the task; and 3) provided training to the affected personnel on the expectations for developing and submitting the Operating Plan to the RC.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2019021535	EOP-004-3	R2	Northern States Power (Xcel Energy)(NSP)	NCR01020	01/30/2019	02/21/2019	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On April 10, 2019, NSP, a Coordinated Oversight Program participant submitted a Self-Log stating that, as a Balancing Authority (BA), Distribution Provider (DP), Generator Owner (GO), Generator Operator (GOP), Transmission Owner (TO) and Transmission Operator (TOP), it was in noncompliance with EOP-004-3 R2. Northern States Power (NSP), PSCO (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program and processed under Northern States Power (Xcel Energy) (NSP) (NCR01020). Xcel Energy reported that it lost its Real-Time Contingency Analysis (RTCA) tool on both its primary and backup Energy Management Systems (EMS) on January 29, 2019, from 15:23 to 15:56, which resulted in a 33-minute loss in post-contingent analysis capability. The loss of monitoring capability at a Control Center for more than 30 minutes requires an EOP-004 report to be submitted within 24 hours of recognition of meeting an event type threshold for reporting. The cause of the noncompliance was that Xcel Energy did not have sufficient controls in place to ensure that the event reporting process was properly followed. The operator did not confirm management staff at the Control Center was aware of the reportable event and able to meet the 24 hour EOP-004 reporting requirement. This noncompliance began on January 30, 2019, 24 hours after the event occurred and the event report should have been submitted, and ended on February 21, 2019, when Xcel Energy submitted the event report.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. No potential harm occurred on the Bulk Electric System as this requirement focuses on after-the-fact event reporting rather than an Operator taking action. Additionally, Xcel Energy's Reliability Coordinator was contacted during the 33-minute event regarding the RTCA loss and took over primary assessment responsibility for the Xcel Energy system until Xcel Energy's RTCA was restored. No harm is known to have occurred. Xcel Energy has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, Xcel Energy: 1) submitted the EOP-004 report; 2) modified its Loss of RTCA procedure to include a step for the Operator to confirm that Control Center management is aware of the event and will be able to meet the 24-hour EOP-004 reporting criteria; 3) trained all operators on the updated Loss of RTCA procedure; and 4) retrained operators in NSP on the Event Reporting procedure to ensure major event notifications are sent for future.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2019022144	TOP-001-4	R21	Omaha Public Power District (OPPD)	NCR00860	07/01/2018	04/03/2019	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from April 9, 2019 through April 11, 2019, MRO determined that OPPD, as a Transmission Operator, was in noncompliance with TOP-001-4 R21. MRO's audit team determined that OPPD did not implement a systematic approach to testing the redundant and diversely routed data exchange infrastructure of its routers. OPPD's TOP-001-4 R20/21 procedure (TOP-001-4 – EMS Operations – Data Exchange) did not include two Southwest Power Pool (SPP) owned routers in the testing procedures as it was assumed that OPPD was not responsible for ensuring that the testing has been performed. Therefore, OPPD failed to test these two components for redundant functionality per the requirements of TOP-001-4. The cause of the noncompliance was that OPPD was not aware that it had the responsibility to ensure that testing was completed for the two routers owned by SPP and located within OPPD's Primary Control Center. The noncompliance began on July 1, 2018, when the standard became effective, and ended on April 3, 2019 when OPPD performed data exchange capability testing that included the SPP owned routers.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. There were no events that occurred on OPPD's system due to the failure of any of the untested devices and the tests did not identify any issues with redundancy of the components. In the event of failure of one of the SPP routers, SPP's failover configuration would have activated the standby router. Lastly, if both routers had failed and OPPD could not restore in a reasonable time, the OPPD backup EMS would have been activated. No harm is known to have occurred. OPPD has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, OPPD: 1) tested the two routers owned by SPP; and 2) updated its TOP-001-4 testing procedure to include components in its Control Centers owned by other entities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2019021128	MOD-032-1	R2	Pierre Municipal Utilities (PMU)	NCR01024	07/01/2017	01/01/2019	Self-Certification	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 2, 2018, PMU submitted a Self-Certification stating that, as a Transmission Owner, it was in noncompliance with MOD-032-1 R2. Specifically, PMU had not identified a Transmission Planner (TP) for its transmission Facilities and therefore, was unable to show that it had provided steady-state, dynamic, or short circuit modeling data to its TP as required by MOD-032-1 R2. The cause of the noncompliance was that PMU failed to identify a TP for its transmission Facilities through the registration process, and therefore was unable to produce evidence that it had satisfied the obligations of its TP's modeling data requirements for MOD-032-1 R2. This noncompliance began on July 1, 2017, when the Standard and Requirement became enforceable, and ended on January 1, 2019, when the agreement was established with a neighboring entity to provide TP services to PMU.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. PMU's TP confirmed that prior to January 1, 2019, the TP had been collecting and submitting PMU model data to the Planning Coordinator per the MOD-032-1 model building process. This supports that the noncompliance is administrative in nature based on the failure to identify a TP, and not related to the provision of necessary date for the model building process. Also, PMU's Bulk Electric System transmission system consists of a 115-kV breaker and a single line section, limiting the potential risk for data quality issues in the model building process had PMU's data not been provided per the date specification. No harm is known to have occurred. PMU has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, PMU: 1) entered into an agreement with its neighboring entity to provide TP services to PMU.

Northeast Power Coordinating Council (NPCC) Compliance Exception O&P

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019021627	MOD-026-1	R4.	Consolidated Edison Co of NY, Inc	NCR07046	10/30/2016	04/19/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On May 29, 2019, Consolidated Edison Company of NY, Inc ("the Entity") submitted a Self-Report stating that as a Generator Owner (GO), it was in noncompliance with MOD-026-1 R4. On April 4, 2019, as a result of an internal compliance review, the Entity discovered that it had failed to provide to its Transmission Planner (TP) verification documentation of a revised excitation control system model for an applicable generating unit. Specifically, on May 2, 2016, during Power System Stabilizer (PSS) tuning activities, the Entity implemented new PSS settings in order to obtain an optimal damping response for a broad range of system frequencies. Per requirement R4 of the standard, the Entity is required to provide such documentation within 180 calendar days of the actual implementation date of the aforementioned changes. This noncompliance started on October 30, 2016, when the Entity exceeded the timeline prescribed by the standard/requirement to provide appropriate documentation to its TP and ended on April 19, 2019, when the Entity provided its TP with an electronic copy of an engineering report detailing changes implemented to the PSS of its applicable generating unit. The root cause of this instance of noncompliance was lack of awareness among responsible staff regarding reporting requirements for revision and validation relating to excitation control systems.
Risk Assessment	This violation posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The Entity's applicable generating unit is currently rated at 224 MVA and been operated at an average capacity factor of 74.51% over the period 2016-2018. The unit is interconnected to a 138-kV substation owned by its host Transmission Owner (TO). Failure to verify the generator excitation control system (including the PSS) and the model parameters used in dynamic simulations of system voltage variations could result in a delayed, outdated or inaccurate assessment of the reliability of the interconnected transmission system. Re-tuning the unit's PSS was rendered necessary by the poor performance exhibited by the original excitation control system following upgrades implemented to increase the manufacturer's rated (MVA) capability to the current values. Prior to tuning activities, the generating unit was experiencing intermittent under-excitation alarms and unsteady VAR control. The new PSS settings improved the generator's dynamic stability margins and damping performance for a wide range of system operating conditions. Additionally, it is noted that the Entity, under its other function of TO, designs and maintains its BES system in accordance with a robust second contingency criterion. This criterion ensures that its system can sustain the non-simultaneous occurrence of two contingency events without violating established performance standards (i.e. thermal/voltage/stability) as well as preventing non-consequential load loss, all of which minimizes the potential degrading impact on the reliability of the interconnected system. The rated capacity of the affected generating unit is approximately 11% of the Entity's Reliability Coordinator (RC) required Operating Reserves (approximately 1965 MW). There's a corresponding amount of reactive capability associated with these (MW) reserves that is determined by individual (on-reserve) generators' capability curves. The Entity's RC (the NYISO) could have adequately compensated for potential risks arising from this instance of noncompliance during declining system voltage/frequency events for the duration of the noncompliance. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined there were no relevant underlying causes.
Mitigation	To mitigate this noncompliance, the Entity: 1) provided to its TP required documentation of revised and validated exciter model parameters; 2) expanded compliance responsibility to multiple departments, including Steam Operations, Central Engineering and Transmission Planning; 3) created new compliance tasks in the Company's work management system to perform verification of exciter and governor models every 5 years; 4) placed appropriate signage at Human Machine Interface (HMI) devices to alert responsible staff that any alteration to equipment response characteristics is subject to NERC's MOD-026-1 requirements; and 5) revised an existing internal NERC compliance procedure with language specifically emphasizing MOD-026-1 and MOD-027-1 compliance tasks.

ReliabilityFirst Corporation (ReliabilityFirst) Compliance Exception O&P

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020458	PRC-024-2	R1	AEP Generation Resources Inc.	NCR11401	7/1/2017	6/1/2018	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On September 21, 2018, ReliabilityFirst determined that the entity, as a Generator Owner, was in noncompliance with PRC-024-2 R1 identified during a Compliance Audit conducted from September 11, 2018 through September 13, 2018. The entity, as a result of an inaccurate interpretation of both PRC-019-2 and PRC-024-2, failed to review the required number of applicable facilities under PRC-024-2. The entity's approach to PRC-019-2 and PRC-024-2 was to perform coordination (PRC-019-2) and the frequency and voltage trip settings (PRC-024-2) in tandem on a given unit. The incorrect calculation was based on the entity's inclusion and exclusion of certain units in its calculation. In the evidence the entity provided during the Compliance Audit, the entity marked some units as having frequency protective relaying, and some as not having frequency protective relaying. This was not clear on all units, however, as instead of marking yes or no for some units, the entity marked "n/a" with a comment of "pending evaluation per implementation" for a number of units. The entity incorrectly concluded that this approach would ensure compliance with the Implementation Plans of both Standards (e.g., if the entity ensured coordination of 40% of their "applicable Facilities" (per PRC-019-2) and simply reviewed 40% of the "applicable Facilities" (per PRC-024-2 - whether or not a given generating unit had frequency or voltage relaying activated to trip the unit), then the entity was 40% compliant with both PRC-019-2 and PRC-024-2. The equation for percentage compliant is calculated as "generating units with frequency protective relaying activated to trip the generating unit with the relays set per R1" divided by "the total number of generating units with frequency protective relaying activated to trip the generating unit". The entity's equation was insufficient because the denominator was artificially decreased as a result of designating some units "n/a", thereby artificially inflating the percentage completion number. The entity also artificially increased the numerator by counting units that did not have frequency protective relaying as being tested on time. Using the entity's incorrect methodology for determining percentage completion, the entity was compliant for each subsidiary on each of the implementation dates. However, using the correct calculations, the entity was compliant or noncompliant as follows: (i) 7/1/2016 Implementation Date: the entity was 80% compliant (4 of 5 units with frequency protective relaying activated to trip the unit) on 7/1/2016 (40% required per the Implementation Plan); (ii) 7/1/2017 Implementation Date: the entity was 0% compliant (0 of 1 units with frequency protective relaying activated to trip the unit) on 7/1/2017 (60% required per the Implementation Plan). The entity sold 12 units between 7/1/2016 and 7/1/2017, which resulted in the percent completion being lower on 7/1/2017 compared to 7/1/2016; and (iii) 7/1/2018 Implementation Date: the entity was 100% compliant (1 of 1 units with frequency protective relaying activated to trip the unit) on 7/1/2018 (80% required per the Implementation Plan). The root cause of this noncompliance was inadequate training and a lack of understanding of NERC PRC-024 requirements, resulting in the incorrect methodology to calculate the requirements under the phased in implementation plan. This noncompliance involves the management practices of verification and workforce management. Verification is involved because the entity failed to assure that its application of PRC-024 was performed correctly. Workforce management is involved because entity employees were not properly trained on the correct interpretation and application of NERC PRC-024-2 requirements. Further, entity employees could have communicated with the Regional Entity to assure proper understanding of NERC Requirements. The noncompliance started on July 1, 2017, when the entity was required to comply with PRC-024-2 R1 and ended on June 1, 2018, when the entity became 100% compliant.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is if units with frequency protective relying activated to trip the unit are not set to not trip in the "no trip" zone, the units may trip during a frequency excursion, exacerbating the frequency excursion. The risk here is minimized because while the entity did not achieve compliance with the implementation dates provided above, it was near compliance in each instance (excluding instances where sales resulted in a drop in the percentage complete) and were actively completing evaluation and testing, albeit pursuant to an incorrect assumption on how to calculate the percent complete. The entity also met some of the implementation deadlines as AEPSC and AEPGR were both compliant as of July 1, 2016. And, importantly, the entities all evaluated and tested 100% of the applicable units ahead of the required completion date for 100% implementation. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) completed testing on the remaining units, as scheduled, prior to July 1, 2019 to meet the 100% milestone per the PRC-024 phased implementation plan within the RF and MRO footprints; and 2) revised its testing procedure and trained new personnel on the procedure.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020459	PRC-024-2	R1	American Electric Power Service Corporation as agent for etc.	NCR00682	7/1/2017	6/1/2019	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On September 21, 2018, ReliabilityFirst determined that the entity, as a Generator Owner, was in noncompliance with PRC-024-2 R1 identified during a Compliance Audit conducted from September 11, 2018 through September 13, 2018. The entity, as a result of an inaccurate interpretation of both PRC-019-2 and PRC-024-2, failed to review the required number of applicable facilities under PRC-024-2. The entity's approach to PRC-019-2 and PRC-024-2 was to perform coordination (PRC-019-2) and the frequency and voltage trip settings (PRC-024-2) in tandem on a given unit. The incorrect calculation was based on the entity's inclusion and exclusion of certain units in its calculation. In the evidence the entity provided during the Compliance Audit, the entity marked some units as having frequency protective relaying, and some as not having frequency protective relaying. This was not clear on all units, however, as instead of marking yes or no for some units, the entity marked "n/a" with a comment of "pending evaluation per implementation" for a number of units. The entity incorrectly concluded that this approach would ensure compliance with the Implementation Plans of both Standards (e.g., if the entity ensured coordination of 40% of their "applicable Facilities" (per PRC-019-2) and simply reviewed 40% of the "applicable Facilities" (per PRC-024-2 - whether or not a given generating unit had frequency or voltage relaying activated to trip the unit), then the entity was 40% compliant with both PRC-019-2 and PRC-024-2. The equation for percentage compliant is calculated as "generating units with frequency protective relaying activated to trip the generating unit with the relays set per R1" divided by "the total number of generating units with frequency protective relaying activated to trip the generating unit". The entity's equation was insufficient because the denominator was artificially decreased as a result of designating some units "n/a", thereby artificially inflating the percentage completion number. The entity also artificially increased the numerator by counting units that did not have frequency protective relaying as being tested on time. Using the entity's incorrect methodology for determining percentage completion, the entity was compliant for each subsidiary on each of the implementation dates. However, using the correct calculations, the entity was compliant or noncompliant as follows: (i) 7/1/2016 Implementation Date: the entity was 57% compliant (8 of 14 units with frequency protective relaying activated to trip the unit) on 7/1/2016 (40% required per the Implementation Plan); (ii) 7/1/2017 Implementation Date: the entity was 25% compliant (2 of 8 units with frequency protective relaying activated to trip the unit) on 7/1/2017 (60% required per the Implementation Plan). The entity sold 6 units between 7/1/2016 and 7/1/2017, which resulted in the percent completion being lower on 7/1/2017 compared to 7/1/2016; and (iii) 7/1/2018 Implementation Date: the entity was 25% compliant (2 of 8 units with frequency protective relaying activated to trip the unit) on 7/1/2018 (80% required per the Implementation Plan). The root cause of this noncompliance was inadequate training and a lack of understanding of NERC PRC-024 requirements, resulting in the incorrect methodology to calculate the requirements under the phased in implementation plan. This noncompliance involves the management practices of verification and workforce management. Verification is involved because the entity failed to assure that its application of PRC-024 was performed correctly. Workforce management is involved because entity employees were not properly trained on the correct interpretation and application of NERC PRC-024-2 requirements. Further, entity employees could have communicated with the Regional Entity to assure proper understanding of NERC Requirements. The noncompliance started on July 1, 2017, when the entity was required to comply with PRC-024-2 R1 and ended on June 1, 2019, when the entity became 100% compliant.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is if units with frequency protective relying activated to trip the unit are not set to not trip in the "no trip" zone, the units may trip during a frequency excursion, exacerbating the frequency excursion. The risk here is minimized because while the entity did not achieve compliance with the implementation dates provided above, it was near compliance in each instance (excluding instances where sales resulted in a drop in the percentage complete) and were actively completing evaluation and testing, albeit pursuant to an incorrect assumption on how to calculate the percent complete. The entity also met some of the implementation deadlines as AEPSC and AEPGR were both compliant as of July 1, 2016. And, importantly, the entities all evaluated and tested 100% of the applicable units ahead of the required completion date for 100% implementation. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) completed testing on the remaining units, as scheduled, prior to July 1, 2019 to meet the 100% milestone per the PRC-024 phased implementation plan within the RF and MRO footprints; and 2) revised its testing procedure and trained new personnel on the procedure.

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020461	PRC-024-2	R1	American Electric Power Service Corporation as agent for etc.	NCR00682	7/1/2016	7/1/2019	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On September 21, 2018, ReliabilityFirst determined, per an existing multi-region registered entity agreement, that AEP as Agent for AEP OK Transco., PSCO, and SWEPCO (NCR01056), as a Generator Owner, was in noncompliance with PRC-024-2 R1 identified during a Compliance Audit conducted from September 11, 2018 through September 13, 2018. The entity, as a result of an inaccurate interpretation of both PRC-019-2 and PRC-024-2, failed to review the required number of applicable facilities under PRC-024-2. The entity's approach to PRC-019-2 and PRC-024-2 was to perform coordination (PRC-019-2) and the frequency and voltage trip settings (PRC-024-2) in tandem on a given unit. The incorrect calculation was based on the entity's inclusion and exclusion of certain units in its calculation. In the evidence the entity provided during the Compliance Audit, the entity marked some units as having frequency protective relaying, and some as not having frequency protective relaying. This was not clear on all units, however, as instead of marking yes or no for some units, the entity marked "n/a" with a comment of "pending evaluation per implementation" for a number of units. The entity incorrectly concluded that this approach would ensure compliance with the Implementation Plans of both Standards (e.g., if the entity ensured coordination of 40% of their "applicable Facilities" (per PRC-019-2) and simply reviewed 40% of the "applicable Facilities" (per PRC-024-2 - whether or not a given generating unit had frequency or voltage relaying activated to trip the unit), then the entity was 40% compliant with both PRC-019-2 and PRC-024-2. The equation for percentage compliant is calculated as "generating units with frequency protective relaying activated to trip the generating unit with the relays set per R1" divided by "the total number of generating units with frequency protective relaying activated to trip the generating unit". The entity's equation was insufficient because the denominator was artificially decreased as a result of designating some units "n/a", thereby artificially inflating the percentage completion number. The entity also artificially increased the numerator by counting units that did not have frequency protective relaying as being tested on time. Using the entity's incorrect methodology for determining percentage completion, the entity was compliant for each subsidiary on each of the implementation dates. However, using the correct calculations, the entity was compliant or noncompliant as follows: (i) 7/1/2016 Implementation Date: the entity was 0% compliant (0 of 12 units with frequency protective relaying activated to trip the unit) on 7/1/2016 (40% required per the Implementation Plan); (ii) 7/1/2017 Implementation Date: the entity was 17% compliant (2 of 12 units with frequency protective relaying activated to trip the unit) on (60% required per the Implementation Plan) 7/1/2017; and (iii) 7/1/2018 Implementation Date: the entity was 50% compliant (6 of 12 units with frequency protective relaying activated to trip the unit) on 7/1/2018 (80% required per the Implementation Plan). The root cause of this noncompliance was inadequate training and a lack of understanding of NERC PRC-024 requirements, resulting in the incorrect methodology to calculate the requirements under the phased in implementation plan. This noncompliance involves the management practices of verification and workforce management. Verification is involved because the entity failed to assure that its application of PRC-024 was performed correctly. Workforce management is involved because entity employees were not properly trained on the correct interpretation and application of NERC PRC-024-2 requirements. Further, entity employees could have communicated with the Regional Entity to assure proper understanding of NERC Requirements. The noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R1 and ended on July 1, 2019, when the entity became 100% compliant.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is if units with frequency protective relying activated to trip the unit are not set to not trip in the "no trip" zone, the units may trip during a frequency excursion, exacerbating the frequency excursion. The risk here is minimized because while the entity did not achieve compliance with the implementation dates provided above, it was near compliance in each instance (excluding instances where sales resulted in a drop in the percentage complete) and were actively completing evaluation and testing, albeit pursuant to an incorrect assumption on how to calculate the percent complete. The entity also met some of the implementation deadlines as AEPSC and AEPGR were both compliant as of July 1, 2016. And, importantly, the entities all evaluated and tested 100% of the applicable units ahead of the required completion date for 100% implementation. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) completed testing on the remaining units, as scheduled, prior to July 1, 2019 to meet the 100% milestone per the PRC-024 phased implementation plan within the RF and MRO footprints; and 2) revised its testing procedure and trained new personnel on the procedure.

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020460	PRC-024-2	R2	American Electric Power Service Corporation as agent for etc.	NCR00682	7/1/2018	6/1/2019	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On September 21, 2018, ReliabilityFirst determined that the entity, as a Generator Owner, was in noncompliance with PRC-024-2 R2 identified during a Compliance Audit conducted from September 11, 2018 through September 13, 2018. The entity, as a result of an inaccurate interpretation of both PRC-019-2 and PRC-024-2, failed to review the required number of applicable facilities under PRC-024-2. The entity's approach to PRC-019-2 and PRC-024-2 was to perform coordination (PRC-019-2) and the frequency and voltage trip settings (PRC-024-2) in tandem on a given unit. The incorrect calculation was based on the entity's inclusion and exclusion of certain units in its calculation. In the evidence the entity provided during the Compliance Audit, the entity marked some units as having voltage protective relaying, and some as not having voltage protective relaying. This was not clear on all units, however, as instead of marking yes or no for some units, the entity marked "n/a" with a comment of "pending evaluation per implementation" for a number of units. The entity incorrectly concluded that this approach would ensure compliance with the Implementation Plans of both Standards (e.g., if the entity ensured coordination of 40% of their "applicable Facilities" (per PRC-019-2) and simply reviewed 40% of the "applicable Facilities" (per PRC-024-2 - whether or not a given generating unit had frequency or voltage relaying activated to trip the unit), then the entity was 40% compliant with both PRC-019-2 and PRC-024-2. The equation for percentage compliant is calculated as "generating units with voltage protective relaying activated to trip the generating unit with the relays set per R2" divided by "the total number of generating units with voltage protective relaying activated to trip the generating unit". The entity's equation was insufficient because the denominator was artificially decreased as a result of designating some units "n/a", thereby artificially inflating the percentage completion number. The entity also artificially increased the numerator by counting units that did not have voltage protective relaying as being tested on time. Using the entity's incorrect methodology for determining percentage completion, the entity was compliant on each of the implementation dates. However, using the correct calculations, the entity was compliant or noncompliant as follows: (i) 7/1/2016 Implementation Date: AEPSC was 56% compliant (18 of 32 units with voltage protective relaying activated to trip the unit) on 7/1/2016 (40% required per the Implementation Plan); (ii) 7/1/2017 Implementation Date: AEPSC was 62% compliant (16 of 26 units with voltage protective relaying activated to trip the unit) on 7/1/2017 (60% required per the Implementation Plan). AEPSC sold 6 units between 7/1/2016 and 7/1/2017 after the 2016 setting verifications; and (iii) 7/1/2018 Implementation Date: AEPSC was 77% compliant (20 of 26 units with voltage protective relaying activated to trip the unit) on 7/1/2018 (80% required per the Implementation Plan). The root cause of this noncompliance was inadequate training and a lack of understanding of NERC PRC-024 requirements, resulting in the incorrect methodology to calculate the requirements under the phased in implementation plan. This noncompliance involves the management practices of verification and workforce management. Verification is involved because the entity failed to assure that its application of PRC-024 was performed correctly. Workforce management is involved because entity employees were not properly trained on the correct interpretation and application of NERC PRC-024-2 requirements. Further, entity employees could have communicated with the Regional Entity to assure proper understanding of NERC Requirements. The noncompliance started on July 1, 2018, when the entity was required to comply with PRC-024-2 R2 and ended on June 1, 2019, when the entity became 100% compliant.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is if units with voltage protective relying activated to trip the unit are not set to not trip in the "no trip" zone, the units may trip during a voltage excursion, exacerbating the voltage excursion. The risk here is minimized because while the entity did not achieve compliance with the implementation dates provided above, they were near compliance in each instance and were actively completing evaluation and testing, albeit pursuant to an incorrect assumption on how to calculate the percent complete. The entities also met some of the implementation deadlines as they were both compliant as of July 1, 2016 and July 1, 2017. And, importantly, the entities all evaluated and tested 100% of the applicable units ahead of the required completion date for 100% implementation. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) completed the remaining units, as scheduled, prior to July 1, 2019 to meet the 100% milestone per the PRC-024 phased implementation plan within the RF and MRO footprints; and 2) revised its testing procedure and trained new personnel on the procedure.

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020462	PRC-024-2	R2	American Electric Power Service Corporation as agent for etc.	NCR00682	7/1/2016	7/1/2019	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On September 21, 2018, ReliabilityFirst determined, per an existing multi-region registered entity agreement, that AEP as Agent for AEP OK Transco., PSCO, and SWEPCO (NCR01056), as a Generator Owner, was in noncompliance with PRC-024-2 R2 identified during a Compliance Audit conducted from September 11, 2018 through September 13, 2018. The entity, as a result of an inaccurate interpretation of both PRC-019-2 and PRC-024-2, failed to review the required number of applicable facilities under PRC-024-2. The entity's approach to PRC-019-2 and PRC-024-2 was to perform coordination (PRC-019-2) and the frequency and voltage trip settings (PRC-024-2) in tandem on a given unit. The incorrect calculation was based on the entity's inclusion and exclusion of certain units in its calculation. In the evidence the entity provided during the Compliance Audit, the entity marked some units as having voltage protective relaying, and some as not having voltage protective relaying. This was not clear on all units, however, as instead of marking yes or no for some units, the entity marked "n/a" with a comment of "pending evaluation per implementation" for a number of units. The entity incorrectly concluded that this approach would ensure compliance with the Implementation Plans of both Standards (e.g., if the entity ensured coordination of 40% of their "applicable Facilities" (per PRC-019-2) and simply reviewed 40% of the "applicable Facilities" (per PRC-024-2 - whether or not a given generating unit had frequency or voltage relaying activated to trip the unit), then the entity was 40% compliant with both PRC-019-2 and PRC-024-2. The equation for percentage compliant is calculated as "generating units with voltage protective relaying activated to trip the generating unit with the relays set per R2" divided by "the total number of generating units with voltage protective relaying activated to trip the generating unit". The entity's equation was insufficient because the denominator was artificially decreased as a result of designating some units "n/a", thereby artificially inflating the percentage completion number. The entity also artificially increased the numerator by counting units that did not have voltage protective relaying as being tested on time. Using the entity's incorrect methodology for determining percentage completion, the entity was compliant on each of the implementation dates. However, using the correct calculations, the entity was compliant or noncompliant as follows: (i) 7/1/2016 Implementation Date: AEPW was 19% compliant (5 of 26 units with voltage protective relaying activated to trip the unit) on 7/1/2016 (40% required per the Implementation Plan); (ii) 7/1/2017 Implementation Date: AEPW was 54% compliant (14 of 26 units with voltage protective relaying activated to trip the unit) on 7/1/2017 (60% required per the Implementation Plan); and (iii) 7/1/2018 Implementation Date: AEPW was 73% compliant (19 of 26 units with voltage protective relaying activated to trip the unit) on 7/1/2018 (80% required per the Implementation Plan). The root cause of this noncompliance was inadequate training and a lack of understanding of NERC PRC-024 requirements, resulting in the incorrect methodology to calculate the requirements under the phased in implementation plan. This noncompliance involves the management practices of verification and workforce management. Verification is involved because the entity failed to assure that its application of PRC-024 was performed correctly. Workforce management is involved because entity employees were not properly trained on the correct interpretation and application of NERC PRC-024-2 requirements. Further, entity employees could have communicated with the Regional Entity to assure proper understanding of NERC Requirements. The noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R1 and ended on July 1, 2019, when the entity became 100% compliant.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is if units with voltage protective relying activated to trip the unit are not set to not trip in the "no trip" zone, the units may trip during a voltage excursion, exacerbating the voltage excursion. The risk here is minimized because while the entity did not achieve compliance with the implementation dates provided above, they were near compliance in each instance and were actively completing evaluation and testing, albeit pursuant to an incorrect assumption on how to calculate the percent complete. The entities also met some of the implementation deadlines as they were both compliant as of July 1, 2016 and July 1, 2017. And, importantly, the entities all evaluated and tested 100% of the applicable units ahead of the required completion date for 100% implementation. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) completed the remaining units, as scheduled, prior to July 1, 2019 to meet the 100% milestone per the PRC-024 phased implementation plan within the RF and MRO footprints; and 2) revised its testing procedure and trained new personnel on the procedure.

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019021338	PRC-005-6	R3	Constellation Maryland Peaker Fleet	NCR11216	9/20/2018	10/12/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On April 8, 2019, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-005-6 R3. On October 12, 2018, 4 calendar month battery testing was scheduled to be performed at the entity's Criterion/Fair Wind site. During the site visit on that day, the plant manager reviewed dates for current and prior tests. This review indicated that the entity was 23 days late performing the 4 calendar month activities. The root cause of this noncompliance was an issue with creating the work order for the testing activities. The entity utilizes a process where work orders are automatically created at the start of each quarter for repetitive inspections and maintenance activities. The issue in this case what that the individual responsible for populating the form for the work order selected the incorrect start date for purpose of calculating the due date for the next maintenance. This root cause involves the management practices of grid maintenance, in that the entity was late performing maintenance and testing work, and reliability quality management, which includes maintaining a system for deploying internal controls. This noncompliance started on September 20, 2018, when the entity was required to have completed the 4 calendar month battery testing and ended on October 12, 2018, when the entity actually completed the testing.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by failing to perform the required maintenance activities on Protection Systems within the required time intervals is that it may result in a failure of the Protection System to operate as expected or required, which may result in reduced reliability of the BPS. The risk was mitigated in this case by the following factors. First, the entity self-identified the issue and was only 23 days late in performing the requisite testing, reducing the amount of time that the risk could have resulted in adverse consequences. Second, the entity was performing 18 calendar month maintenance and testing activities, which is more comprehensive than the 4 calendar month activities and helps reduce the risk that the batteries would not function as expected. Third, the generating facility at issue is a wind farm rated at 70 MW, which minimizes the potential impact of any harm. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) created a battery testing schedule to generate Work Orders on fixed ninety day intervals for battery maintenance and testing; 2) provided reinforcement training with affected operations personnel with respect to quarterly maintenance schedule testing; 3) created tracking notifications which will be automatically sent out to management prior to the 120 day maximum interval if the Work Order has not been closed after the due date; and 4) set up testing activities to meet a new schedule with battery maintenance schedule has been modified.

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020609	EOP-004-3	R3	CPV Maryland, LLC	NCR11706	12/31/2017	10/4/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On October 22, 2018, the entity submitted a Self-Report to ReliabilityFirst stating that, as a Generator Operator and Generator Owner, it was not in compliance with EOP-004-3 R3. On February 14, 2017, the entity brought a natural gas-fired 2x1 combined cycle 745 MW electric generation facility (the Plant) into commercial operation. Prior to the start of commercial operations, the entity engaged a third party operations and maintenance contractor (the Contractor) to operate the plant and to perform services necessary to ensure that the entity was in compliance with its obligations relating to the Plant. The entity was responsible for overseeing the Contractor's NERC compliance program. The entity performed its oversight duty by participating in multiple meetings with the Contractor before, during, and after commissioning of the Plant; communicating with the Contractor personnel who were on site at the Plant regarding compliance; and communicating with the Contractor's corporate NERC personnel regarding compliance of the Plant. During his time with the entity, the Contractor turned over the management team at the Plant significantly, including three different plant managers. On July 23, 2018, based on ineffective communication and a lack of responsiveness from the Contractor, the entity replaced the Contractor with a new operations and management contractor (the Second Contractor). Upon hiring the Second Contractor, the entity directed the Second Contractor to perform a comprehensive review of the entity's compliance program as it relates to the NERC standards which apply to a Generator Owner/Generator Operator. The Second Contractor identified the following noncompliance. While the entity had a procedure in place that outlined the compliance requirements of EOP-004-3 R3 and required actions of the Contractor, the Second Contractor found no evidence that the Contractor validated the Emergency Operating plan contact information by December 31, 2017, as required. The root cause of this noncompliance was that the entity did not have an adequate verification control to assure that the Contractor responsible for NERC compliance took the steps necessary to be fully compliant. This noncompliance involves the management practices of external interdependencies and verification. External interdependencies management is involved because the noncompliance arose from the failure of a contractor and the entity's inadequate oversight of that contractor. Verification management is involved because the entity failed to confirm that the Contractor was properly performing its NERC compliance functions. The noncompliance began on December 31, 2017, the date the entity was required to comply with EOP-004-3 R3. The noncompliance ended on October 4, 2018, the date the entity validated its Emergency Operating Plan contact information.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk associated with failing to validate the contact information in the Operating Plan is that if the entity experienced a reportable event, it may have outdated contact information for relevant entities. The risk is minimized because, there were multiple backup contacts included in the Operating Plan increasing the likelihood of an effective contact. Further minimizing the risk, the entity commenced commercial operations in early 2017, decreasing the likelihood that the contact information was outdated or changed from the information originally entered. Additionally, having outdated contact information would likely only delay the entity's communication and not prevent it because the entity could find the correct information if a reportable event occurred. Reliability First notes that when the entity validated the contact information on October 4, 2018, no changes to the contacts were necessary, and thus for the time period of the noncompliance, the entity had the correct contact information on hand. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) implemented a revised EOP-004-3 R3 compliance procedure; 2) entered a task to validate contact information entered into the entity's compliance management system, called Gensuite, to automatically remind Plant Management to complete the task annually; and 3) required Plant Management to execute an EOP-004 Compliance Attestation after the validation is completed and uploaded to Gensuite. ReliabilityFirst has verified the completion of all mitigation activity.

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020614	MOD-032-1	R2	CPV Maryland, LLC	NCR11706	6/15/2017	6/19/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On October 22, 2018, the entity submitted a Self-Report to ReliabilityFirst stating that, as a Generator Owner, it was not in compliance with MOD-032-1 R2. On February 14, 2017, the entity brought a natural gas-fired 2x1 combined cycle 745 MW electric generation facility (the Plant) into commercial operation. Prior to the start of commercial operations the entity engaged a third party operations and maintenance contractor (the Contractor) to operate the plant and to perform services necessary to ensure that the entity was in compliance with its obligations relating to the Plant. The entity was responsible for overseeing the Contractor's NERC compliance program. The entity performed its oversight duty by participating in multiple meetings with the Contractor before, during, and after commissioning of the Plant; communicating with the Contractor personnel who were on site at the Plant regarding compliance; and communicating with the Contractor's corporate NERC personnel regarding compliance of the Plant. During his time with the entity, the Contractor turned over the management team at the Plant significantly, including three different plant managers. On July 23, 2018, based on ineffective communication and a lack of responsiveness from the Contractor, the entity replaced the Contractor with a new operations and management contractor (the Second Contractor). Upon hiring the Second Contractor, the entity directed the Second Contractor to perform a comprehensive review of the entity's compliance program as it relates to the NERC standards which apply to a Generator Owner/Generator Operator. The Second Contractor identified the following noncompliance. While the entity had a procedure in place that outlined the compliance requirements of MOD-032-1 R2 and required actions of the Contractor; the Contractor failed to perform them, resulting in this noncompliance. Specifically, the Contractor was required to respond to PJM's annual request to confirm or update the relevant modeling data, but the Contractor failed to respond to PJM. The root cause of this noncompliance was that the entity did not have an adequate verification control to assure that the Contractor responsible for NERC compliance took the steps necessary to be fully compliant. This noncompliance involves the management practices of external interdependencies and verification. External interdependencies management is involved because the noncompliance arose from the failure of a contractor and the entity's inadequate oversight of that contractor. Verification management is involved because the entity failed to confirm that the Contractor was properly performing its NERC compliance functions. The noncompliance began on June 15, 2017, the date the entity was required to comply with MOD-032-1 R2. The noncompliance ended on June 19, 2018, the date the entity submitted the necessary modeling to PJM for 2018.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The potential risk associated with failing to timely submit modeling data to PJM is that the data used in PJM's models could be incorrect, impacting the accuracy of the models. The risk here is minimized because the entity submitted initial MOD-032 data to PJM, and PJM did not notify the entity that the initial submission was insufficient under MOD-032-1 R2; thus PJM possessed sufficient modeling information. Further, this type of information does not typically change in any meaningful way. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) implemented a revised MOD-032-1 compliance procedure; and 2) added the annual MOD-032-1 Data submittal task to the Plant's compliance monitoring system, called Gensuite, which will automatically remind Plant Management of the upcoming task. In addition, because the due date for MOD-032-1 submittals can vary depending on when PJM sends out the request for data, the Gensuite task reminders will automatically remind Plant Management several times in advance of the expected submittal date so that they can monitor for PJM's request for data, and then submit the required data once a due date is set. ReliabilityFirst has verified the completion of all mitigation activity.

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020610	PRC-001-1.1(ii)	R1	CPV Maryland, LLC	NCR11706	2/14/2017	9/24/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On October 22, 2018, the entity submitted a Self-Report to ReliabilityFirst stating that, as a Generator Operator, it was not in compliance with PRC-001-1.1(ii) R1. On February 14, 2017, the entity brought a natural gas-fired 2x1 combined cycle 745 MW electric generation facility (the Plant) into commercial operation. Prior to the start of commercial operations the entity engaged a third party operations and maintenance contractor (the Contractor) to operate the plant and to perform services necessary to ensure that the entity was in compliance with its obligations relating to the Plant. The entity was responsible for overseeing the Contractor's NERC compliance program. The entity performed its oversight duty by participating in multiple meetings with the Contractor before, during, and after commissioning of the Plant; communicating with the Contractor personnel who were on site at the Plant regarding compliance; and communicating with the Contractor's corporate NERC personnel regarding compliance of the Plant. During his time with the entity, the Contractor turned over the management team at the Plant significantly, including three different plant managers. On July 23, 2018, based on ineffective communication and a lack of responsiveness from the Contractor, the entity replaced the Contractor with a new operations and management contractor (the Second Contractor). Upon hiring the Second Contractor, the entity directed the Second Contractor to perform a comprehensive review of the entity's compliance program as it relates to the NERC standards which apply to a Generator Owner/Generator Operator. The Second Contractor identified the following noncompliance. While the entity had a procedure in place that outlined the compliance requirements of PRC-001-1.1(ii) and required actions of the Contractor; the Contractor failed to perform them, or failed to document them, resulting in this noncompliance. Specifically, the Contractor was to ensure that Plant operations personnel were familiar with Protection System Schemes in the area which includes knowledge of not only internal Protection System Schemes but also those which impact the operations of the Transmission Owner/Transmission Operator and other nearby Protection System Schemes. The Contractor stated that the requisite PRC-001-1.1(ii) training was performed. However, no records exist to establish that the Contractor performed the Protection System scheme training. The entity claimed that it had trained personnel familiar with the purpose and limitations of Protection System schemes applied in its area, but the appropriate evidence of training was not maintained for PRC-001-1.1(ii) R1. The root cause of this noncompliance was that the entity did not have an adequate verification control to assure that the Contractor responsible for NERC compliance took the steps necessary to be fully compliant. This noncompliance involves the management practices of external interdependencies and verification. External interdependencies management is involved because the noncompliance arose from the failure of a contractor and the entity's inadequate oversight of that contractor. Verification management is involved because the entity failed to confirm that the Contractor was properly performing its NERC compliance functions. The noncompliance began on February 14, 2017, the date the entity was required to comply with PRC-001-1.1(ii) R1. The noncompliance ended on September 24, 2018, the date the entity completed training for its operations personnel on the purpose and limitations of area Protection Schemes.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this noncompliance is that if operations personnel do not understand the purpose and limitations of the Protection System schemes in the area, the personnel could incorrectly analyze the Protection System design or intent resulting in unplanned outages or Protection System misoperations. The risk here is minimized because the entity staff had technical specialists and management personnel onsite who were knowledgeable as to an overview of the entity's electrical distribution system and relay vendors were available for guidance during the self-reported period. The risk is further minimized because the Plant's generation protection scheme is equipped with real-time monitoring and alarming to the control room which would alert operators of abnormal conditions. Additionally, entity staff were required to engage engineering staff where a significant generation distribution event occurred. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) implemented a revised PRC-001-1.1(ii) compliance procedure; 2) trained operating staff on the revised PRC-001-1.1(ii) procedure; and 3) implemented System Protection Coordination procedure which requires that the Plant Manager or designee ensure the facility personnel are familiar with existing protective systems and when any changes and/or modifications are made to protection systems. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020826	VAR-002-4.1	R1	Exelon Generation Company, LLC	NCR04057	1/15/2018	9/5/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 7, 2018, the entity submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with VAR-002-4.1 R1. On September 5, 2018, entity personnel coordinated with Vestas, the turbine manufacturer of Michigan Wind 2 (MW2), to support reactive power testing required by MOD-025. As a result of the coordination, Vestas discovered that the Control Loop, a voltage control device, was off. The entity could not determine why the Control Loop had been turned off. Vestas immediately reactivated the Control Loop and then reviewed logs to determine the duration of the incident. Vestas determined that the issue started on January 15, 2018. The entity did not have control access to the Automatic Voltage Regulator (AVR) to activate or deactivate the voltage control device for MW2. Further, the entity's operations center which monitors MW2 does not have visual reference to the Voltage Control Loop, so the entity checks the Voltage Setpoint and Actual Voltage to determine if the facility is within operating range. The facility was within the operating range for the period in question. The voltage schedule for Michigan Wind 1 (MW1) and MW2 at the connecting 120 kV bus is 122 kV +/- 4 kV. The generator voltage schedule was valid at the time when the facility was producing roughly 10% of nameplate, or 16 MW. Both MW1 and MW2 provide voltage support at the point of interconnection. The entity reviewed 2018 data at the high-side breaker at the point of interconnection for the approximately 4,050 hours of the noncompliance and determined that the operation was within the voltage target range during this period. However, the entity failed to notify the Transmission Operator (TOP) that AVR was not being used. The root cause of this noncompliance of not making the required notification of the change in status of the AVR stemmed from insufficient internal controls to identify the change in status and notify remote operations that a change in status occurred at MW1. This noncompliance involves the management practices of verification and grid operations. Verification management is involved because the entity failed to implement the necessary internal controls to assure that notice that the entity was operating without AVR was provided to the TOP. Grid operations management is involved because the entity failed to communicate important operational information to the TOP. This noncompliance started on January 15, 2018, when the entity inadvertently turned off the Control Loop for MW2 and ended on September 5, 2018, when the entity reactivated the Control Loop.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by failing to notify the TOP of a change in the status of the AVR is that if deviations from the prescribed and coordinated scheduled voltage occurred, the TOP may be delayed in taking action in a timely manner to restore the system to the prescribed voltage levels. The risk here is minimized because the entity was monitoring real time voltage levels for the duration of the noncompliance, which is why the voltage for MW2 never departed from the voltage target range at the point of interconnection. Further minimizing the risk, an entity operating at approximately 16 MW has a limited ability to substantially impact voltage. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) reactivated the AVR and returned it to service; 2) summarized the AVR issue in an email to ITC, and confirmed that operation was within the voltage target from January 15, 2018 to September 5, 2018; 3) collaborated with Vestas in order to bring the Control Loop visibility into entity operations; 4) updated operations procedures to add a step to confirm Control Loop was active; 5) provided training to operations personnel regarding notification to transmission operators for loss of AVR; 6) installed notification capability to notify when the Control Loop is not active at MW1 and MW2; and 7) installed a notification capability to notify when the Control Loop is not active at another generating facility.

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019021647	VAR-002-4.1	R2	FirstEnergy Utilities as agent for etc.	NCR11315	5/12/2018	5/27/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On May 30, 2019, the entity submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with VAR-002-4.1 R2. On two occasions, the entity did not notify the Transmission Local Control Center (LCC) within the 30 minute notification requirement for voltage schedule deviations. (Per PJM Manual 3, section 3.11, note 1, Generator Operators are expected to maintain their assigned voltage schedule and notify the LCC when a generator is outside of the specified voltage schedule limits continuously for thirty minutes unless otherwise specified by the Transmission Owner.) The first occurred at the Yards Creek generation plant on May 12, 2018 and the second occurred at the Yards Creek generation plant on May 27, 2018. Real-Time Dispatch Operators (Operator) use the Generation Management System (GMS) to monitor the Yards Creek generation plant's adherence to the voltage schedule that is assigned by the Transmission LCC. A 30 minute rolling average voltage value is used for voltage schedule monitoring. The GMS alarms the Operator when the thirty-minute rolling average voltage value is outside of the assigned voltage schedule upper and lower bands so that notification to the LCC is made within the 30 minute notification requirement. During planned GMS maintenance activities, the automatic population of the upper and lower voltage schedule bands was temporarily disabled. During this time, the Operator was instructed to scan tag (set manually) the upper and lower voltage schedule bands to 228.5 kV and 235.5 kV respectively in order to ensure proper monitoring continued. The Operator inadvertently scan tagged the 30-minute rolling average voltage value instead of the upper voltage schedule band (235.5 kV). This action resulted in GMS alarms not activating for voltage excursions due to the thirty-minute rolling average voltage value being inadvertently manually entered. As a result, the Operator did not receive an alarm on two different occasions and did not notify the LCC within the thirty-minute notification requirement. The entity identified this issue through a detective control report completed by entity staff which found two instances where the Yards Creek plant deviated from its voltage schedule for 30 minutes or more and where the entity did not make proper notification to the transmission LCC for the referenced deviations. The entity conducted a full extent of condition review. The entity evaluated generation unit outputs for all units that could have been outside of their voltage schedule that required notification to the LCC during the timeframe in question and found no other instances. This noncompliance involves the management practices of workforce management, reliability quality management, and verification. The root cause of this noncompliance was that the Operator inadvertently scan tagged the 30-minute rolling average value instead of the upper voltage schedule band (235.5 kV) which resulted in the Operator not being aware when the upper voltage schedule band was exceeded. The entity did not have an effective internal control in place to ensure that the Operator scan tagged the correct value. This noncompliance started on May 12, 2018, when the entity first deviated from its voltage schedule at the Yards Creek generation plant for more than 30 minutes without notifying its Transmission LCC and ended on May 27, 2018 when the entity returned to compliance with its voltage schedule at the end of the second instance.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed is not maintaining a voltage schedule could allow for detrimental generator voltage levels. The risk is minimized because the 30-minute rolling average for the May 12, 2018 incident deviated from the schedule limit on average by 0.5 kV, which is just 0.21%, for 4 hours and 21 minutes. The 30-minute rolling average for the May 27, 2018 incident deviated from the schedule limit on average by 1.5 kV, which is just 0.64%, for 2 hours and 19 minutes. The small deviations and short durations help minimize the risk. Additionally, the entity self-identified the instances and thereafter implemented a control to prevent recurrence. No harm is known to have occurred. The entity has relevant compliance history. However, ReliabilityFirst determined that the entity's compliance history should not serve as a basis for applying a penalty because while the result of some of the prior noncompliances were arguably similar, the prior noncompliances arose from different causes.
Mitigation	To mitigate this noncompliance, the entity: 1) removed the scan tag that was inadvertently placed on the incorrect point in the GMS and the thirty-minute rolling average voltage excursion alarm was activated; 2) established a process where Real-time Dispatch Operations personnel will verify "scan tagged" points at shift change; 3) conducted refresher training for Operators regarding the voltage schedule monitoring process as well as reminders on the use and monitoring of scan tagged points in the GMS; and 4) provided greater on-screen visibility to operators that will emphasize when the thirty-minute rolling average voltage value is scan tagged in the GMS.

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019022399	PRC-006-2	R9	PPL Electric Utilities Corporation	NCR00884	2/10/2016	12/18/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On March 31, 2019, the entity submitted a self-log stating that, as a Distribution Provider and Transmission Owner, it was in noncompliance with PRC-006-2 R9. While reviewing relay protection settings for unrelated work, an engineer identified protection relays where the automatic underfrequency load shedding (UFLS) settings were disabled and questioned if the entity was satisfying its UFLS requirements. Upon further review, the entity identified UFLS settings that were disabled on February 10, 2016, for 59.3 Hz and April 11, 2016, for 58.5 Hz, which dropped entity load shedding below 10% for each frequency bandwidth. The settings were disabled per entity policy because vital facilities were being served by the respective feeders. Per PRC-006, the Planning Coordinator (PJM) notified the entity of its UFLS requirement of 10% for each frequency bandwidth. The entity notified PJM of the discrepancy and correction. The root cause of this noncompliance was that responsible personnel failed to follow the entity's procedure relating to changing settings to disable UFLS. The procedure required verification of the UFLS calculation, but the entity did not implement sufficient controls to prevent or detect this noncompliance. This noncompliance implicates the management practices of implementation and workforce management. When an organization decides to implement a change, it is important for the organization to ensure that that the change does not compromise the reliability and resilience of the bulk power system (BPS). Through effective workforce management, including the development and communication of clear, thorough, and executable procedures, an entity can minimize issues typically encountered when implementing changes. This noncompliance started on February 10, 2016, when the entity initially disabled UFLS settings and ended on December 18, 2018, when the entity updated the settings and frequency schemes.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious and substantial risk to the reliability of the BPS. Having incorrect settings could impair an entity's ability to (a) assist in arresting declining frequency, (b) assist in recovery of frequency following underfrequency events, and (c) provide last resort system preservation measures. Here, the risk was minimized because the UFLS capacity was minimally below the 10% required at the referenced levels and the automatic tripping of load would have shed load as needed during an event. The following factors also reduced the risk. The load shed for 58.9 Hz was 23 MW over the required 10%. While the entity was short on load shedding capacity at 59.3 Hz and 58.5 Hz, each of the three steps of their UFLS would have resulted in a combined total load shed of 29.2% (i.e., 2,085.7 MW) rather than the required 30% (i.e., 2,142 MW) if frequency dropped to 58.5 Hz. Lastly, the entity has only needed to operate the UFLS once in the prior 22 years (1996). No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, the entity: 1) updated relay settings and frequency schemes for UFLS to meet required MW levels; 2) updated its relevant procedure with detail on roles and responsibilities and new controls to ensure UFLS requirements are met; and 3) communicated the updated procedure to all stakeholders.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019022025	PRC-005-6	R3	Arkansas Electric Cooperative Corporation (AECC)	NCR01060	07/01/2019	07/31/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On August 5, 2019, AECC submitted a Self-Report stating that, as a Transmission Owner (TO), it was in noncompliance with PRC-005-6 R3. AECC failed to maintain its communications Protection System components, which are included within the time-based maintenance program, in accordance with four-month interval required within Table 1-2. On February 11, 2019, AECC verified that the communication systems for the Pinnacle and Morrilton East 161 kV lines, which connect to the Whillock HS9 Plant, were functional per Table 1-2. AECC had scheduled its next communications testing for May 26, 2019 through May 31, 2019. However, on May 24, 2019, the access road to the Whillock HS9 Plant and Switching Station flooded causing the Plant and the Switching Station to be inaccessible. On the same day, AECC took the Morrilton East Line Terminal out of service at Whillock HS9. Four days later, on May 28, 2019, the Whillock HS9 Switching Station flooded and AECC took the Pinnacle Line Terminal out of service at Whillock HS9. After the flood waters receded, AECC completed the repairs on the transmission lines on July 19, 2019. AECC completed the testing for the Morrilton East and the Pinnacle 161 kV lines on July 31, 2019. This noncompliance started on July 1, 2019, when AECC exceeded the four-month interval to complete the communications system testing, and ended on July 31, 2019, when AECC completed the communications system testing. The root cause of this noncompliance was flooding at the Whillock HS9 Switching Station. The flooding caused damage to the Pinnacle Transmission Line and the Whillock HS9 Switching Station, which made it impossible for AECC to perform the required testing within the defined four-month interval.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The failure to perform communications systems tests has the potential to increase the risk of misoperations. However, in this instance, the Whillock HS9 plant was unavailable during this flooding period, and the Whillock HS9 to Morrilton East and the Whillock HS9 to Pinnacle lines were out of service prior to exceeding the four-month maximum maintenance testing interval. Impact was limited to single station and radial 161 kV lines. No harm is known to have occurred. SERC considered AECC's PRC-005-6 R3 compliance history in determining the disposition track. AECC's relevant prior noncompliance with PRC-005-6 R3 includes: NERC Violation ID SPP2012010432. SERC determined that AECC's PRC-005-6 R3 compliance history should not serve as a basis for aggravating the penalty. The underlying cause of the instant noncompliance is completely unrelated to the prior instances of noncompliance, and the associated mitigation plans could not have prevented the instant noncompliance.
Mitigation	To mitigate this noncompliance, AECC: 1) performed all required maintenance and testing activities on the unmonitored communication devices at Whillock HS9; and 2) as part of its preventative control, had its Compliance Service and Power Delivery's Subject Matter Experts schedule and conduct Quality Evidence Reviews (QERs). AECC conducts a minimum of four reviews in a calendar year. AECC checks a random sampling of protection system and UFLS system evidence for completion and being in an "audit-ready" conduction.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019022184	VAR-002-4.1	R1	Cypress Creek O&M, LLC (InnSol46)	NCR11867	07/22/2019	07/23/2019	Self-Report	Complete

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 9, 2019, InnSol46 submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with VAR-002-4.1 R1. InnSol46 did not operate its generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the Transmission Operator (TOP). On July 22, 2019, while performing testing of the plant controller, the operator switched the Automatic Voltage Regulator (AVR) into manual control mode at approximately 12:00 pm. Following the testing, the operator failed to return the AVR to service. On July 23, 2019, at 10:00 a.m. (approximately 22 hours after the plant controller was initially removed from AVR mode), another operator discovered that the AVR was not enabled and immediately re-enabled the AVR and notified the TOP as required. This noncompliance started on July 22, 2019, at 12:30 p.m. when InnSol46 failed to return the unit's AVR back to the automatic mode following the maintenance activities, and ended July 23, 2019, at 10:00 a.m., when the plant operator returned the unit to AVR mode. The causes of the noncompliance were: 1) the operator was using a single-use testing procedure that had only been reviewed by one person and did not have adequately specific instructions for notifying the TOP of the change in AVR status and returning the unit back to AVR mode. 2) The pre-job brief was not effective to ensure the operator understood how the testing would affect the AVR functionality, and there was a lack of oversight and peer-check during the performance of the testing. 3) There was a lack of situational awareness tools to alert operators that the AVR mode was disabled.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Failure to maintain the AVR in automatic mode could result in uncontrolled voltage transients. However, InnSol46 maintained its voltage schedule throughout the noncompliance, the TOP did not require or request any corrections or changes, and the transmission system maintained the normal operation. The operator took corrective action as soon as the identifying the discrepancy and the AVR was in manual operation mode for less than 24 hours. InnSol46 is a single solar facility with a capability of 79 MVA / 26 MVAR and a capacity factor of 21.5%. No harm is known to have occurred. SERC considered InnSol46 compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, InnSol46: 1) returned the AVR to service and notified the TOP as required; 2) implemented an alarm into SCADA, which alerts operators if a facility is not operating in AVR mode; 3) implemented a new protocol requiring operators to verify the AVR status for facilities during start of shift and end of shift checklists; 4) held a meeting with the control center management team to review the incident. Based on the discussion, the proper process for procedure review was reinforced with operations leadership team and the plant operations team to ensure procedures address items like notification to the TOP when required. The expectation was set by management that all procedures, including single use procedures, would be reviewed by minimum of two people and that any procedure potentially involving compliance with NERC standards would be reviewed by the Operational Compliance team. Additionally, expectations for pre-job briefs and oversight of activities were reinforced to ensure that non-routine activities are properly communicated to the operators, they understand the activity, and have adequate oversight or resources if questions arise; 5) completed a refresher training with the operators on the AVR functionality and TOP notification protocol; and 6) completed an extent-of-condition by reviewing operator logs and SCADA data from the past year (since GOP registration 7/1/18) to determine if any other potential non-compliance instances exist. No additional instances of non-compliance were found.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019022185	VAR-002-4.1	R3	Cypress Creek O&M, LLC (InnSol46)	NCR11867	07/22/2019	07/23/2019	Self-Report	Complete

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 9, 2019, InnSol46 submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with VAR-002-4.1 R3. InnSol46 failed to notify its Transmission Operator (TOP) of a status change on the Automatic Voltage Regulator (AVR) within 30 minutes of the change. On July 22, 2019, while performing testing of the plant controller the operator switched the AVR into manual control mode at approximately 12:00 pm. The operator, however, failed to notify the TOP of this initial change in status of the AVR within 30 minutes of the status change as required by VAR-002-4.1 R3. On July 23, 2019, at 10:00 a.m. (approximately 22 hours after the plant controller was initially removed from AVR mode), another operator discovered that the AVR was not enabled and immediately re-enabled the AVR and notified the TOP as required. Again, the TOP notification at the conclusion of testing did not include that the AVR was out of service. This noncompliance started on July 22, 2019, at 12:30 p.m., when InnSol46 failed to notify the TOP that the AVR was out of service and in manual mode, and ended July 23, 2019, at 10:00 a.m., when the plant operator returned the unit to AVR mode and notified the TOP. The causes of the noncompliance were: 1) the operator was using a single-use testing procedure that had only been reviewed by one person and did not have adequately specific instructions for notifying the TOP of the change in AVR status and returning the unit back to AVR mode. 2) The pre-job brief was not effective to ensure the operator understood how the testing would affect the AVR functionality and there was a lack of oversight and peer-check during the performance of the testing. 3) There was a lack of situational awareness tools to alert operators that the AVR mode was disabled.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The risk posed by the AVR being in manual mode without timely informing the TOP is that the TOP could make decisions which impact the BPS based on faulty or incomplete information. However, InnSol46 maintained its voltage schedule throughout the noncompliance, the TOP did not require or request any corrections or changes, and the transmission system maintained normal operation. The operator took corrective action as soon as the identifying the discrepancy. The AVR was in manual operation mode for less than 24 hours. InnSol46 is a single solar facility with a capability of 79 MVA / 26 MVAR and a capacity factor of 21.5%. No harm is known to have occurred. SERC considered InnSol46 compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, InnSol46: 1) returned the AVR to service and notified the TOP as required; 2) Implemented an alarm into SCADA which alerts operators if a facility is not operating in AVR mode; 3) implemented a new protocol requiring operators to verify the AVR status for facilities during start of shift and end of shift checklists; 4) held a meeting with the control center management team to review the incident. Based on the discussion, the proper process for procedure review was reinforced with operations leadership team and the plant operations team to ensure procedures address items like notification to the TOP when required. The expectation was set by management that all procedures, including single use procedures, would be reviewed by minimum of two people and that any procedure potentially involving compliance with NERC standards would be reviewed by the Operational Compliance team. Additionally, expectations for pre-job briefs and oversight of activities were reinforced to ensure that non-routine activities are properly communicated to the operators, they understand the activity, and have adequate oversight or resources if questions arise; 5) completed a refresher training with the operators on the AVR functionality and TOP notification protocol; and 6) completed an extent-of-condition by reviewing operator logs and SCADA data from the past year (since GOP registration 7/1/18) to determine if any other potential non-compliance instances exist. No additional instances of non-compliance were found.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017018468	PRC-005-6	R3	Duke Energy Carolinas, LLC (DEC)	NCR01219	12/01/2016	04/05/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 12, 2017, Duke Energy Carolinas (DEC) submitted a Self-Report stating that, as a Transmission Owner, it was in noncompliance with PRC-005-6 R3. DEC reported that it failed to perform the required maintenance on two carrier communication systems in accordance with its Protection System Maintenance Program (PSMP). On September 15, 2016, DEC completed the installation of the Mauldin Black Transmission Line between the Cane Creek Tie and the Greenbriar Switching. The completion of the line added network connectivity to multiple stations and also caused the stations' protective equipment to become subject to PRC-005 maintenance. The protective equipment included a battery supply at Laurens EC Delivery 25 (Laurens), as well as, new carrier sets at the Greenbrier Switching Station, Cane Creek Tie and Laurens. The Contract Relay Technician failed to submit the carrier test data and Terminal Activity Report Form (TAR) for the completed installation of the equipment. Because the Contract Relay Technician did not submit the TAR, the carrier systems at the Greenbrier Switching Station, Cane Creek Tie and Laurens were not identified in the PSMP database, therefore, DEC failed to initiate work orders to perform the maintenance on the equipment. Maintenance was due on all of the carrier systems on January 31, 2017 and maintenance was due on the battery at Laurens on November 30, 2016 and February 28, 2017. On March 4, 2017, DEC began an investigation into the relay operation on the Cane Creek Tie and discovered that it was missing commission test data at the Greenbriar Switching Station and Laurens and, subsequently, that it failed to add the stations' protective equipment to the PSMP database, which was in noncompliance with DEC's internal process, the BES Checklist. On November 9, 2017, DEC submitted an expansion of scope identifying the two additional instances where it failed to perform the required quarterly battery maintenance at Laurens and maintenance on the carrier system at Cane Creek Tie. DEC completed maintenance on the battery at Laurens on April 4, 2017 and completed maintenance on the carrier systems at Cane Creek Tie, Greenbrier Switching Station, and Laurens on April 5, 2017. This noncompliance started on December 1, 2016, when DEC should have performed its battery maintenance at Laurens, and ended on April 5, 2017, when DEC performed its carrier functional check at Cane Creek Tie, Greenbriar and Laurens. The root causes of this noncompliance were a lack of training and ineffective internal controls. The Technician failed to submit the TAR form after the installation of the equipment and the Entity did not have an adequate process to flag the missing form.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The potential impact to the BPS was minimal because this carrier is only 1 of 258 carriers within the DEC system. Additionally, DEC discovered this noncompliance as a result of an internal control used following an actual operation of this carrier system. When DEC reviewed the equipment database, it discovered that the test data was missing for this equipment. DEC scheduled the crews to return and validate that the equipment was set and tested properly. When tested, DEC found the equipment to be set properly and it tested well with no documented issues. No harm is known to have occurred. SERC determined that DEC's compliance history should not serve as a basis for applying a penalty. DEC's relevant compliance history with PRC-005-1 R2 involves one 2010 instance, and the underlying cause for the prior instance is different; therefore, the mitigation plan for the prior instance did not address and could not have prevented the instant issue. SERC reviewed the posted violations of PRC-005 for affiliates of DEC, Duke Energy Corporation (DECorp), Duke Energy Progress (DEP), and Duke Energy Florida (DEF) and did not identify circumstances similar to that of the instant issue. Each Duke Energy affiliate is responsible for its own maintenance and testing program and the completed mitigation plans would not have addressed the instant issue.
Mitigation	To mitigate this noncompliance, DEC: 1) sent the Construction, Maintenance, and Vegetation (CMV) Relay Crew to test the carrier system on the Mauldin Black 100kv Transmission Line at the Greenbriar Switching Station and saved NERC PRC- 005 data; 2) submitted a TAR and completed: a. quarterly battery inspection at Laurens EC Delivery 25 and saved NERC PRC-005 data; b. a work order for quarterly carrier inspection at the Greenbriar Switching Station on the Mauldin Black 100kv Transmission Line and saved NERC PRC-005 data; 3) communicated with DEC, DECorp, DEP, and DEF CMV Relay Teams the expectation of submitting paperwork weekly that supports NERC compliance; 4) updated the current BES Checklist (STDF-PJM-TRM-00002) to the updated draft version (noted in appendix) that will need to be reviewed and approved as deemed appropriate by Transmission Compliance Coordination; 5) communicated the updated BES Checklist (STDF-PJM-TRM-00002) to the appropriate functional groups; and 6) developed and delivered a training package for affected work groups that participate in the BES checklist process to promote awareness of the form and process.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019022041	PRC-002-2	R12	Duke Energy Carolinas, LLC (DEC)	NCR01219	05/15/2019	05/30/2019	Self-Report	01/22/2020

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On August 12, 2019, Duke Energy Carolinas (DEC) submitted a Self-Report stating that, as a Transmission Owner, it was in noncompliance with PRC-002-2 R12. DEC failed to restore the recording capability or submit a Corrective Action Plan (CAP) to the Regional Entity and implement the CAP within 90 days of discovering a failure on a Digital Fault Recorder (DFR). DEC has a process where a subject matter expert (SME) tracks the status of failed Disturbance Monitoring Equipment (DME) to ensure that DEC repairs or submits a CAP to SERC within 90 days. On February 13, 2019, the DFR at Belews Creek Station failed, and, on May 14, 2019, the 90 day window of the Standard concluded for DEC to submit a CAP to SERC and or restore the recording capability. On May 30, 2019, DEC submitted a CAP to SERC and sent the failed DFR to the manufacturer for repair. The delay for these actions was due to the SME tracking the issue being on an extended absence due to illness. The missed deadline and delay were discovered as part of the existing process when the SME returned from the absence. On June 24, 2019, DEC reinstalled, tested, and confirmed the DFR to be operational. This noncompliance started on May 15, 2019, when DEC failed to repair the recording capability or submit a CAP to SERC within 90 calendar days of discovering the failed DFR, and ended on May 30, 2019, when DEC submitted a CAP to SERC. The cause of the noncompliance was a deficient procedure. The procedure in place, a preventative control, did not account for the likely possibility that the responsible SME could be unavailable for an extended period of time. Additionally, the reminder, a secondary preventative control, also failed when it did not appropriately inform the SME of the urgency and deadline required by the Standard.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). DEC's failure to restore the recording capability or submit a CPA to SERC and implement it within 90 calendar days of the discovery of the failure could have put the long-term health of the BPS at risk. However, the equipment in question is for post-event analysis only. Additionally, the loss of such equipment could not lead to transmission or generation loss on its own. Furthermore, the window of noncompliance lasted a total of 15 days further, and thus, limiting potential harm. No harm is known to have occurred. SERC considered DEC's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, DEC: 1) submitted the CAP for the failed DFR, and repaired, reinstalled, tested and confirmed that the faulty equipment was operational. To mitigate this noncompliance, DEC will complete the following mitigation activities by January 22, 2020: 1) review, update, and implement a formal DEC process for PRC-002-2 R12 to include definition of roles and responsibilities related to DME failure tracking, creation and classification of work orders, and track status and trigger CAP submittal; and 2) implement process changes by identifying all process stakeholders and training all stakeholders on the revised process. DEP has not been able to complete its Mitigation Plan because it is still in the process of updating their internal procedures and needs sufficient time to roll out the updates in a training module.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SPP2017018290	PRC-005-6	R3	Louisiana Energy & Power Authority (LEPA)	NCR01116	05/16/2017	11/9/2018	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted on August 29, 2017, Southwest Power Pool Regional Entity (SPP RE) determined that LEPA, as a Generator Owner (GO), was in noncompliance with PRC-005-6 R3. LEPA failed to provide evidence that it met the maintenance and testing requirements of PRC-005-6 R3 for all devices. Upon dissolution of SPP RE, the Alleged Violation was transferred to SERC. LEPA 1 was a new 69 MW combined cycle unit and is the only generation unit for LEPA. On November 15, 2015, LEPA 1 connected to the grid to begin testing. During the first quarter of 2016, the plant became commercial. The contractor was to complete the LEPA 1 commissioning tests, which included those required for PRC-005-6. LEPA did not receive all of the test reports because the contractor performing the testing did not provide all test reports to LEPA. LEPA 1 had experienced many problems since initial operation and had yet to reach a stable operating state. The SPP audit team found that LEPA was unable to provide documented evidence of commissioning testing for two out of 17 protective relays, four out of four battery banks, 41 out of 48 current transformers, and five out of nine potential transformers. SERC determined that, in accordance with FERC Order 793, LEPA was not required to provide commissioning data to show compliance during the SPP audit. As a result, the LEPA batteries were the only Protection System devices that did not meet the requirements of PRC-005-6 R3. LEPA failed to complete the 18-month resistance testing that was due on May 16, 2017, 18-months after LEPA's unit 1 connected to the grid. The audit team reported a noncompliance for four sets of batteries, but after further review of the batteries, one set of the batteries was determined not to be a Bulk Electric System (BES) element because it did not supply power to BES protection systems. This noncompliance started on May 16, 2017, when LEPA failed to perform the 18-month battery resistance testing, and ended on November 9, 2018, when LEPA completed the battery resistance testing. The cause of this noncompliance was LEPA's failure to include the 18-month resistance testing in the work-order for the contractor.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. LEPA's failure to perform testing activities upon commissioning could cause Protection System relays to operate prematurely, which would cause the unit to trip unnecessarily. Alternatively, LEPA'S failure to perform testing activities upon commissioning could cause Protection System relays to fail to operate, which would cause the next upstream Protection System relay to operate to clear the fault and impact more of the BPS than necessary. However, neither LEPA nor its Transmission Planner (TP) considered LEPA 1 to be a critical resource. Additionally, the impact of the 69 MW unit was minuscule compared to the total generation in the TP's footprint. Furthermore, because LEPA 1 had yet to reach a stable operating state, LEPA was not relying on LEPA 1 to meet load requirements. No harm is known to have occurred. SERC considered LEPA's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, LEPA: 1) created a spreadsheet of all elements and the associated test records; 2) identified all protective relays, battery banks, current transformers, and potential transformers with missing test records; 3) completed the protective relay, current transformer, and potential transformer maintenance and testing activities; 4) created a testing schedule for all the equipment to ensure maintenance is performed within the testing intervals of PRC-005-6; 5) communicated to staff and plant manager the updated testing schedule; 6) installed new batteries and performed the required testing; and 7) updated the maintenance schedules for the batteries.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019022100	PRC-024-2	R1	Orlando Utilities Commission (OUC)	NCR00057	07/01/2018	09/17/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On August 21, 2019, OUC submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R1. OUC failed to set its protective relaying such that the generator frequency protective relaying did not trip the applicable generating units within the "no trip zone" of PRC-024 Attachment 1, in accordance with the NERC Implementation Plan. OUC owns and operates two coal fired units at the Stanton Energy Complex (SEC), with a total generation capacity of 1,032 MVA nameplate, which connects at 230 kV. The net MVA rating for Unit 1 is 516 MVA with a capacity factor of 56.9%. The net MVA rating for Unit 2 is 516 MVA with a capacity factor of 64.5% On April 15, 2019, during an internal review, OUC discovered that Stanton Unit 1 and Stanton Unit 2 had frequency relays that were set in the "no trip zone." After this discovery, OUC first verified with Siemens that the set point could be moved without causing damage to the generators and, after receiving verification from Siemens, OUC changed the set point for Stanton Unit 1 from 59.4 Hz to 59.0 Hz at 360 seconds on August 2, 2019. OUC changed the set points for Stanton Unit 2 on September 17, 2019. OUC performed an extent-of-condition (EOC) and determined that six out of its eight generating units (75%) met the July 1, 2017, 60% Implementation Plan date. The two generating units, Stanton Unit 1 and Unit 2, caused OUC to miss the July 1, 2018, 80% Implementation Plan date and July 1, 2019, 100% Implementation Plan date. This noncompliance started on July 1, 2018, when OUC was required and failed to meet the 80% Implementation Plan, and ended on September 17, 2019, when OUC set Stanton Unit 2's generator frequency protective relaying to not trip the applicable generating units within the "no trip zone". The root cause of this noncompliance was a lack of internal control to track compliance dates. Specifically, OUC did not delegate a specific person to track and follow up on compliance activities required by the business units.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because of the short duration of this noncompliance, which was approximately 10 weeks. Additionally, the two facilities at issue in this noncompliance have not experienced any trips due to the applicable settings either during the implementation period or prior to the existence of the Standard. No harm is known to have occurred. SERC considered OUC's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, OUC: 1) completed under-frequency set point settings from 59.4Hz to 59.0Hz at 360 seconds on Stanton Unit 1; 2) completed under-frequency set point from 59.4Hz to 59.0Hz at 360 seconds during the Stanton 2 Outage; 3) performed extent-of-condition review finding no additional instances of noncompliance; and 4) identified Program Managers (PM) to be responsible for specific standards and requirements that will work closely with the business units to track and follow up on compliance activities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021981	COM-002-4	R2	Owensboro, KY Municipal Utilities (OWENSB)	NCR01290	07/01/2016	07/07/2016	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from July 8, 2019 to July 12, 2019, SERC determined that OWENSB, as a Transmission Operator, was in noncompliance with COM-002-4, R2. OWENSB failed to conduct initial communication protocol training for one system operator before the system operator was in a position to issue an Operating Instruction. OWENSB has five system operators. OWENSB trained four of the system operators on the required communication protocol (Version 7) prior to July 1, 2016, during the Reliability Coordinator (RC) Restoration Drills. However, the fifth system operator did not participate in a RC Restoration Drill until after July 1, 2016. The system operator in question had been trained on Version 6 of the OWENSB Communication Protocols. However, Version 6 did not contain at a minimum Requirement R1, P1.4, as required by COM-002-4. On July 7, 2016, six days late, the system operator at issue received the required OWENSB Communication Protocols training. During the period in question, the system operator performed Operating Instructions correctly and did not issue any Operating Instructions during an emergency. This noncompliance started on July 1, 2016, when the system operator was on-shift and in a position to give an Operating Instruction the required communication protocol training, and ended July 7, 2016, when the operator completed the training. The cause of this noncompliance was a lack of an effective internal control to verify and track required system operator training.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. OWENSB's failure to ensure all applicable operating personnel completed initial training for OWENSB's Communications Protocols could limit the operators' awareness of communication protocols, which could increase the possibility of miscommunication. However, this issue concerned a single, experienced operator who had completed the prior version (Version 6) training for OWENSB's Communication Protocols prior to implementation of COM-002-4. For the period of time in question, the operator issued Operating Instructions correctly and did not issue any Operating Instructions during an emergency. Additionally, OWENSB is a relatively small system consisting of three interconnections, which are owned by another registered entity. OWENSB has never issued a written or oral single-party to multiple-party burst Operating Instruction, nor does it ever expect to issue a written or oral Operating Instruction due to the small size of the system. Furthermore, the OWENSB substation and its associated transmission lines operate at more than 100kV, but the substation and its associated transmission lines meet the criteria for exclusion from the Bulk Electric System, per exclusion E3 – Local networks. No harm is known to have occurred. SERC considered OWENSB's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, OWENSB: 1) trained the system operator on the OWENSB Communication Protocols, Version 7, (which includes multi-party instructions per COM-002-4 R1.4) on July 7, 2016, during the RC Restoration Drill; 2) modified the system operator training to include annual OWENSB Communication Protocols Training; 3) conducted system operator retraining on OWENSB Communication Protocols; 4) developed an internal control to track system operator training task that included a routing and approval process with reminder e-mails that escalate as the training due date approaches; and 5) revised its Internal Compliance Program to require quarterly meetings with topic experts to discuss recently revised OWENSB communication procedures and training requirements.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021993	TPL-001-4	R8	Owensboro, KY Municipal Utilities (OWENSB)	NCR01290	03/22/2017	04/10/2018	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from July 8, 2019 to July 12, 2019, SERC determined that OWENSB, as a Transmission Planner (TP), was in noncompliance with TPL-001-4, R8. OWENSB failed to distribute its 2016 Planning Assessment results to adjacent Planning Coordinators (PC) and adjacent TPs within 90 calendar days of completing its Planning Assessment. On December 21, 2016, OWENSB completed and signed its 2016 Planning Assessment. On March 22, 2017, OWENSB was required to have distributed its Planning Assessment to its adjacent PCs and TPs. Because OWENSB participated in the 2016 SERC PC modeling groups and study activities, OWENSB did provide Planning Assessment data as needed to its adjacent PCs and TPs. However, OWENSB could not provide the documentation (an e-mail confirmation receipt) proving that it provided the 2016 assessment to the adjacent PCs and TPs. On April 10, 2018, OWENSB provided the approved 2017 OWENSB Planning Assessment to the adjacent PCs and TPs. This noncompliance started on March 22, 2017, 91 days after completion of the 2016 Planning Assessment, and ended on April 10, 2018, when OWENSB distributed its 2017 Planning Assessment results to adjacent PCs and TPs. The cause of the noncompliance was that the applicable procedure did not clearly define the approval process for distributing annual Planning Assessments.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. OWENSB's failure to distribute its Planning Assessment within 90 days of completion could result in adjacent PCs and TPs lacking awareness of changes planned for the OWENSB transmission system, and therefore, the Entities could not properly assess the potential implications of those changes on the adjacent systems. However, as a registered TP, OWENSB shares information regarding its system, including planned changes, through joint modeling and study activities it participates in with adjacent PCs and TPs. These joint model development and study reports provide methods of information sharing with neighboring PCs and TPs pre-date the January 1, 2016 enforceable date of TPL-001-4 R8, and continue to serve as an effective means of informing adjacent entities of future plans. No harm is known to have occurred. SERC considered OWENSB's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, OWENSB: 1) distributed the 2017 Planning Assessment to adjacent PCs and TPs; 2) implemented a routing and approval process with reminder emails. OWENSB requires management approval of the Planning Assessment beginning with the 2017 Planning Assessment. The approved Assessment is routed to the Transmission and Distribution (T&D) Operations System Supervisor to be filed. Receipt of the approved Assessment prompts the T&D Operations System Supervisor to notify the Senior Operations Engineer to provide an approved copy to neighboring PCs and TPs. These tasks provide management oversight and formalize the approval and distribution processes; 3) trained all applicable employees on new routing and approval process; and 4) revised its Internal Compliance Program to require quarterly meetings of topic experts to discuss completed and pending transmission planning and modeling activities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021033	MOD-027-1	R4.	Tennessee Valley Authority (TVA)	NCR01151	10/10/2017	07/24/2018	Self-Report	02/06/2020

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On February 6, 2019, TVA submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-027-1 R4. TVA failed to provide revised model data or plans to perform model verification for an applicable unit to its Transmission Planner (TP) within 180 calendar days of making changes to the turbine/governor control systems that altered the equipment response characteristic. On July 12, 2018, a Power Operations (PO) NERC Compliance Manager was updating the Design Change Notice (DCN) Tracking Database and noted some MOD-027-1 Governor Models that TVA failed to revise and validate. TVA replaced the turbine/governor controls systems for Caledonia Unit 2, Southaven Unit 2, and Southaven Unit 3. Caledonia Unit 2 is a 271 MW unit with an annual average capacity factor of 68%. Southaven Unit 2 is a 274 MW unit with an annual average capacity factor of 60%. Southaven Unit 3 is a 261 MW unit with an annual average capacity factor of 55%. On April 12, 2017, Caledonia Unit 2 returned to service, TVA should have provided the revised model data to its TP by October 9, 2017. On July 8, 2017, Southaven Unit 3 returned to service, and TVA should have provided the revised model data to its TP by January 4, 2018. On January 12, 2018, Southaven Unit 2 returned to service, and TVA should have provided the revised model data to its TP by July 11, 2018. On July 24, 2018, TVA submitted a Model Revision and Verification Plan to its TP for each of the three units. TVA provided the required data to its TP 288 days late for Caledonia Unit 2, 13 days late for Southaven Unit 2, and 201 days late for Southaven Unit 3. This noncompliance started on October 10, 2017, when TVA failed to provide its TP updated model information, and ended on July 24, 2018, when TVA submitted a Model Revision and Verification Plan to its TP for each of the three units. The cause of the violation was a procedural deficiency, specifically, undocumented roles and responsibilities, which caused confusion as to who was responsible for communication the discovered possible compliance issues. The compliance review of the work identified possible compliance impacts associated with the system changes; however, the compliance group did not ensure that the project leads were aware of the requirements. TVA's NERC Compliance Groups misunderstood who had responsibility for notifying the project lead.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The risk posed by TVA's failure to provide accurate generator model information to the TP could potentially have led to inefficient planning of future generation interconnections or caused inaccuracies in long term capacity and outage planning. However, the generation capability associated with the three generation units was less than 2% of the total TVA MVA generation capability, which reduced the likelihood of either potential harm. In addition, TVA is improving its MOD-027-1 models of generators tied to the TVA Transmission System based on the requirements of MOD-027-1 R2. The TVA Transmission System reliability improves with each accepted submitted MOD-027-1 R2 generator model data. TVA as a Generator Owner has submitted the R2 requirement for 59% of its applicable units, which is in advance of the July 1, 2020 Implementation Plan requirement of 50%. No harm is known to have occurred. SERC considered TVA's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, TVA will complete the following mitigation activities by February 6, 2020: 1) submit a plan to verify MOD-027 Models for Caledonia Combined Cycle Units 2 and Southaven Combined Cycle Units 2 & 3 to the TP; 2) coordinate with Caledonia Combined Cycle Site Management and the performing vendor for MOD-027-1 Model verification Testing on Unit 2; 3) coordinate with Southaven Combined Cycle Site Management and the performing vendor for MOD-027-1 Model verification Testing on Units 2 & 3; 4) submit MOD-027-1 Model of Caledonia Combined Cycle Unit 2 to Transmission Planning; 5) submit MOD-027-1 Model of Southaven Combined Cycle Unit 2 & 3 to Transmission Planning; 6) determine the list of PO Design Change Notice DCNs in the PO NERC Compliance Design Change Notice Tracking Database for DCNs marked as having possible MOD-026-1 and MOD-027-1 impacts since May 1, 2016; 7) document the instructions on how to identify and address DCNs potentially impacting NERC MOD-026-1 and MOD-027-1: a. define clear roles and responsibilities for those involved in the DCN review; b. ensure adequate tracking of NERC impacts identified by the reviews; c. communicate/train the groups and individuals with roles in the DCN reviews; and 8) review each DCN of the list from action 6 to determine extent of condition: a. identify the NERC MOD-026-1 &-027-1 impacts associated with each DCN; and b. take the necessary actions to maintain/ensure NERC Compliance.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018020787	EOP-005-2	R17	Tenaska Gateway Partners LTD (TGCCS)	NCR04137	01/01/2018	02/22/2018	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted per an existing multi-region registered entity agreement from October 29, 2018, through December 11, 2018, Texas RE determined that Tenaska Gateway Partners LTD (TGCCS) TGCCS, as Generator Operator (GOP), was in noncompliance with EOP-005-2 R17. In particular, TGCCS did not provide sufficient evidence to show that each of its operating personnel responsible for the startup of its Blackstart Resource generation units received two hours of training prior to January 1, 2018, which is the date when two of TGCCS's generation units became Blackstart Resources. Electric Reliability Council of Texas, Inc.'s (ERCOT ISO) Blackstart Resource designation for two of TGCCS's generation units became effective on January 1, 2018. While TGCCS's change management documentation does indicate that some training was provided to TGCCS's operating personnel as part of the implementation of the Blackstart Resource designation and while TGCCS did perform a successful test of its generation units' Blackstart capability, TGCCS was unable to provide evidence reflecting the content of the training or evidence demonstrating that the training had been conducted for two hours for each of the four applicable operating personnel, as required by EOP-005-2 R17. On February 22, 2018, TGCCS's operating personnel attended training provided by ERCOT ISO regarding the Blackstart program, ending the noncompliance. The root cause of this issue is that TGCCS did not have a sufficient process to document the completion of trainings as part of its change management process. In particular, TGCCS's change management form indicates that training was required and provided, but TGCCS did not retain documents sufficient to demonstrate that the training it provided met the requirements of EOP-005-2 R17. This noncompliance started on January 1, 2018, when TGCCS's Blackstart Resource designation became effective, and ended on February 22, 2018, when TGCCS's operating personnel attended training provided by ERCOT ISO regarding the Blackstart program.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk posed by this noncompliance is that, if the operating personnel responsible for implementing the system restoration plan did not receive adequate training, those personnel may not be able to effectively execute the system restoration plan, which could lead to delayed system restoration following an event. However, the risk posed by this issue was reduced by the following factors. First, the duration of the noncompliance was short, lasting less than two months. Second, ERCOT ISO did not experience any events during the noncompliance that required TGCCS to perform its Blackstart procedure. Third, although TGCCS did not retain documentation to show that all four of its applicable operating personnel received two hours of training, three out of four of TGCCS's applicable operating personnel participated in a Blackstart exercise in coordination with ERCOT ISO personnel to demonstrate that TGCCS's generation units were capable of serving as a Blackstart Resource. No harm is known to have occurred. Texas RE considered TGCCS's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, TGCCS: 1) provided training to its operating personnel consistent with the requirements of EOP-005-2 R17; and 2) implemented new compliance management software to track tasks and documentation requirements for compliance with EOP-005-2.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017756	BAL-005-0.2b	R17	Avista Corporation (AVA)	NCR05020	1/1/2017	5/25/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible or confirmed violation.)	On June 16, 2017, AVA submitted a Self-Report stating that, as a Balancing Authority, it was in noncompliance with BAL-005-0.2b R17. Specifically, AVA did not complete its annual check and calibration of its GPS clock at the System Operations Primary Control Center (PCC) and the GPS clock at the System Operations Backup Control Center (BCC) at least annually in 2016. This issue began on January 1, 2017, when the did not annually test two, time error and frequency devices and ended on May 25, 2017, when AVA completed the check and calibration test on is time error and frequency devices for the GPS clock at the System Operation PCC and the GPS Clock System Operations BCC for a total of 145 days. The root cause of the issue was attributed to lack of a documented verification process before removing task schedules from the automated compliance tracking system. The personnel responsible for this task incorrectly believed that this Standard and Requirement were no longer mandatory and removed the reminder from the automated compliance tracking system without verifying the retirement date of the Standard and Requirement.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, AVA failed to at least annually check and calibrate its time error and frequency devices against a common reference for the GPS clock at the System Operation PCC and the GPS Clock System Operations BCC. Such failure could have resulted in an incorrect calculation of the frequency component of the Area Control Error (ACE). An incorrect ACE value could lead to over or under generation, thus affecting the frequency of the interconnection. However, as compensation, AVA’s frequency bias is 1.2% of the regional frequency bias, which is a small part of ACE, reducing the risk. In addition, the digital Frequency Time and Deviation Monitor within the GPS clocks is accurate and previous tests showed that the accuracy was within the precision of the smallest incremental capability of the test equipment, therefore it is unlikely calibration of these devices is ever needed. WECC considered AVA's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this issue, AVA has: 1) completed the check and calibration of the time error and frequency devices of the GPS clock at the System Operation PCC and the GPS Clock System Operations BCC; 2) updated internal user guide for creating, completing and retiring review of Standard and Requirement to require review before any tasks are removed; 3) added a task reminder for BAL-005-0.2b R17 to be added into the automated compliance tracking system; WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019836	PRC-005-6	R1	Avista Corporation (AVA)	NCR05020	1/2/2017	12/22/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On June 12, 2018, AVA submitted a Self-Report stating that, as a Generator Owner and Transmission Owner, it was in noncompliance with PRC-005-6 R1. Specifically, AVA did not update its Protection System Maintenance Program (PSMP) to include two component types, both Automatic Reclosing and Sudden Pressure Relaying before the effective date of the Implementation Plan for R1. This issue began on January 2, 2017, when the Implementation Plan R1 became mandatory for Automatic Reclosing and Sudden Pressure Relaying and ended on December 22, 2017, when AVA updated its PSMP for a total of 355 days. The root cause of the issue was attributed to lack of tracking by AVA to ensure compliance with effective dates of the Implementation Plan.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, AVA failed to establish a Protection System Maintenance Program (PSMP) for its Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying identified in Section 4.2, Facilities, as required by PRC-005-6 R1. Failure to establish a PSMP that includes Automatic Reclosing and Sudden Pressure Relaying could potentially result in not having Automatic Reclosing and Sudden Pressure Relaying in working order, which could potentially result in the loss of portions of the entity's transmission and generation system. However, as compensation, AVA had a PSMP that it was using when this instant issue was discovered. In addition, the instant issue was a documentation error. AVA's relevant prior compliance history with PRC-005-1 R2 and PRC-005-1b R2 includes NERC Violation IDs: WECC2013011979, WECC200700417 and WECC200901813. WECC determined AVA's compliance history should not serve as a basis for pursuing an enforcement action and/or applying a penalty. The instant issue relates to AVA's PSMP not being updated according to the Implementation Plan, rather than the implementation of the PSMP, thus the instant issue and previous violations have different facts and circumstances.
Mitigation	To mitigate this issue, AVA has: 1) updated to PSMP to include the required information for Automatic Reclosing and Sudden Pressure Relays; 2) launched Implementation Plan task schedules to include the task schedules for the remaining effective dates associated with PRC-005-6 Implementation Plan have entered into AVA's software tracking system; and 3) implemented an Internal Compliance Program (ICP) control to ensure future Standards will have formal implementation plans and are properly maintained; WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2019021249	PRC-005-1.1b	R2	Avista Corporation (AVA)	NCR05020	3/5/2016	1/8/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On March 18, 2019, AVA submitted a Self-Report stating that, as a Transmission Owner, it was in noncompliance with PRC-005-1.1b R1. Specifically, AVA did not provide evidence that Protection System devices were maintained and tested within the defined intervals according to PRC-005-1.1b R2. AVA did not maintain and test three monitored microprocessor relays within the maintenance and testing interval defined in its Protection System Maintenance Program (PSMP). This issue began on March 5, 2016, when the first of three microprocessor relays were not maintained according to its intervals and ended on January 8, 2019 when the three microprocessor relays were maintained for a total of 1,040 days. The root cause of the issue was attributed to an error in a manually scripted query in its software database that caused the three microprocessor relays to be omitted from the yearly work plans, resulting in AVA missing the maintenance interval for these three relays.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, AVA failed to provide documentation of its PSMP that all Protection System devices were maintained and tested within the defined intervals, specifically three microprocessor relays, as required by PRC-005-1.1b R2. One relay is at a 115 kV switching station and protects two 115kV transmission lines, another relay is at a different 115 kV switching station that is associated with parts of a WECC Major Transfer Path and protects a 115kV transmission line, and the last relay is at a 115/13 kV substation and protects the 115kV transmission line. Failure to maintain Protection System devices within the defined intervals could reasonably result in the three relays failing to operate properly in the event of a fault. However, as compensation, AVA implemented redundant independent Protection Systems that perform the detection and operation for faults. These redundant Protection Systems would have operated to clear a fault. In addition, the three relays operated properly during the period of the instant issue, and all three relays did not have deficiencies when they were tested. In addition, the relays are monitored microprocessor relays. As well, the actual and defined maintenance intervals for these three relays were less than the 12-year maximum maintenance interval for monitored microprocessor relays of the requirements of the current Standard. AVA's relevant prior compliance history with PRC-005-1 R2 and PRC-005-1b R2 includes NERC Violation IDs: WECC2013011979, WECC200700417 and WECC200901813. WECC determined AVA's compliance history should not serve as a basis for pursuing an enforcement action and/or applying a penalty. NERC Violations WECC2013011979 and WECC200700417 were both minimal risk violations related to different devices that followed a different facts and circumstances pattern. The NERC Violation WECC200901813 was a minimal risk, documentation error that have different facts and circumstances than the instant issue.
Mitigation	To mitigate this issue, AVA has: 1) tested and maintained the three microprocessor relays; and 2) improved functionality within its software database to build standard queries using improved functionality that does not require the user to manually script queries to prevent human error.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2019021441	PRC-004-5(i)	R5	Avista Corporation (AVA)	NCR05020	8/23/2017	Present	Compliance Audit	11/30/2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible or confirmed violation.)	During a Compliance Audit conducted from April 22, 2019 through April 26, 2019, WECC determined that the entity, as a Transmission Owner, was in noncompliance with PRC-004-5(i) R17. Specifically, AVA did not complete an evaluation of its Corrective Action Plan (CAP) for three Misoperations. AVA had three Misoperations: the first on June 16, 2017, the second on October 3, 2017 and a third on October 3, 2017, as well. For each Misoperation, AVA developed a CAP for each within 60 of identifying the cause, the first Misoperation was identified on June 23, 2017, the second Misoperation was identified on October 3, 2017 and the third Misoperation was also identified on October 3, 2017. However, AVA did not include an evaluation of the CAP’s applicability to AVA’s other Protection Systems including other locations. This issue began on August 23, 2017 60 days after AVA identified the cause of the first Misoperation and is still ongoing. The root cause of the issue was attributed to a lack of understanding of the requirements of the Standard. AVA incorrectly only documented the evaluation of the CAP’s was applicable to other Protection System devices, instead of documenting that the evaluation was performed, and the results of the evaluation were included.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, AVA failed to include in its CAP for the Misoperation of the identified Protection System components, an evaluation of the CAP’s applicability to AVA’s other Protection Systems including other locations, within 60 calendar days of first identifying a cause of the Misoperation as required by PRC-004-5(i) R5. Failure to evaluate the CAP's applicability to the entity's other Protection Systems could reasonably result in corrective actions not being taken for other applicable Protection Systems, potentially resulting in subsequent Misoperations with the same cause. The first Misoperation occurred at a 230kV switchyard, and the second and third Misoperations occurred at a 115kV substations. AVA owns and maintains 2,250 miles of 115kV and 230kV transmission. However, as compensation, AVA developed and implemented the CAP within the appropriate timelines for all Misoperations where the cause had been identified, reducing the risk of recurrence of the Misoperations. WECC considered AVA’s compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To remediate and mitigate this issue, AVA will complete the following by November 20, 2019: 1) perform an evaluation of the CAP’s applicability to AVA’s other Protection Systems including other locations; 2) restore compliance for second and third Misoperations: a) perform a fault study to determine source and direction of sequence quantities; b) characterize the devices; c) identify BPS Facilities with same characteristics; d) evaluate the Protection Systems at Facilities for CAP applicability; and e) implement CAP. 3) restore compliance for first Misoperation: a) develop the criteria to define a short transmission line for AVA; b) identify AVA’s short transmission line Facilities based on the criteria; c) evaluate the Protection Systems at Facilities eligible for CAP applicability; and d) implement the CAP. 4) modify the Misoperations evaluation procedure to include all required actions and documentation to evaluate applicability of a CAP; 5) modify the Protection System Operations database to include a section specific to the CAP applicability evaluation that will record a date/time stamp when completed; 6) establish a weekly report for review by the Manager that identifies the status of the misoperation for root cause analysis, CAP development and CAP applicability evaluation; and 7) implement an automated monthly recurring data request from AVA's compliance management system to identify the dates of any Misoperations that have occurred and issue a compliance task to ensure that a CAP applicability evaluation is completed within the required timeline. All mitigation activities must be completed within 12 months of the date of this notice.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017018879	TOP-001-3	R13	Portland General Electric Company (PGE)	NCR05325	10/5/2017 10/7/2017 10/7/2017 12/11/2017	10/5/2017 10/7/2017 10/7/2017 12/11/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On December 22, 2017, PGE submitted a Self-Report stating that, as a Transmission Operator (TOP), it had a potential noncompliance with TOP-001-3 R13. PGE is a vertically integrated company. As such, PGE had four issues with TOP-001-3 R13 that it did not ensure that a Real-time Assessment (RTA) was performed at least once every 30 minutes. All four instances were discovered during PGE's monthly review of its Real-time Contingency Analysis tool's (RTCA) activities. The first instance occurred on October 5, 2017, at 9:08 PM when the RTA was due and ended at 9:47 PM, when the RTA was performed, for a total of 39 minutes, 9 minutes over the 30-minute requirement of the Standard. The second instance occurred on October 7, 2017, at 3:28 PM and ended at 4:02 PM, for a total of 34 minutes, 4 minutes over the 30-minute requirement of the Standard. The third instance occurred on October 7, 2017, at 4:40 PM and ended at 5:20 PM, for a total of 40 minutes, 10 minutes over the 30-minute requirement of the Standard. The fourth instance occurred on December 11, 2017, at 11:50 PM and ended at 1:50 AM, for a total of 120 minutes, 90 minutes over the 30-minute requirement of the Standard. The root cause was attributed to the System Operator not being trained properly to perform an RTA in response the RTCA alarms. Specifically, the cause of the first three instances was due to the System Operator's incomplete training on how to react to an RTCA alarm that indicated the RTCA failed to converge. In the fourth instance, the same System Operator was unable to distinguish the failure-to-converge alarm due because it was only a visual alarm, not auditory like the previous instances.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, PGE failed on four occasions, to ensure that a RTA was performed at least once every 30 minutes, as required by TOP-001-3 R13. Such failure could have resulted in PGE not being completely aware of the state of its system for contingent conditions which could cause an exceedance of an System Operating Limit (SOL), instability, uncontrolled separation, or cascading outages, as required by TOP-001-3 R13. However, PGE implemented strong detective controls. Specifically, PGE's transmission operations engineers analyzed a monthly report to determine how well the Transmission Operators are performing with the RTCA tool which discovered the issues above. As compensation, if there had been an SOL exceedance during the period when the RTCA tool was not converging, other control alarms would have alerted the Transmission Operators of the situation, reducing the likelihood of the instant violation causing risk to the BPS. In addition, each instance of RTCA not converging was relatively short in duration. WECC determined PGE had no prior relevant instances of noncompliance.
Mitigation	To mitigate this issue, PGE has: 1) its RTCA converged after all four instances; 2) the Transmission and Distribution manager issued an email to the System Operators explaining the importance of the RTCA non-converged alarms; 3) reissued the procedure for the System Operators to review to minimize the likelihood of further issues; 4) during a System Control Center staff meeting, the Transmission and Distribution Manager discussed the importance of monitoring the RTCA tool, including the non-converged alarm, as a training; 5) configured the RTCA tool to automatically reset each day at midnight. By resetting the alarm at midnight, the number of false alarms has been substantially reduced; 6) changed the non-converged alarm to a different audible sound than the other system control center alarms so that the System Operators are better able to distinguish it; 7) reconfigured the EMS alarm code so that the alarm remains visible on the screen beyond the acknowledgement stage until the Operator manually clears the alarm. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019708	PRC-023-2	R1	Western Area Power Administration – Rocky Mountain Region (WACM)	NCR05464	9/23/2014	10/3/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible or confirmed violation.)	On May 18, 2018, WACM submitted a Self-Report stating that, as a Transmission Owner, it was in potential noncompliance with PRC-023-2 R1. Specifically, during a review of relay settings, WACM discovered that it had not applied one of the criteria from PRC-023-2 R1 to a specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System (BES) for all fault conditions. The specific relay's overcurrent setting was set to 3.8 amps, but the correct setting was 6.8 amps. The root cause was attributed to a lack of internal controls. Specifically, the aforementioned relay setting was manually entered incorrectly during a project in 2014 that changed the settings. WACM used a word file to define the settings and transferred them to a relay database and then applied the settings to the relay. In the process of transferring the information from the word file to the relay database, there was a typo in the relay setting, which resulted in the wrong setting being applied to the device. WACM did not validate that the relay setting was applied correctly between documentation and to the actual device. This issue began on September 23, 2014, when WACM did not correctly set its phase protective relay settings from limiting transmission system loadability and ended on October 3, 2017, when WACM updated the settings on the relay, for a total of 1,107 days.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, WACM failed to use one of the criteria for a specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions, for one relay. WACM was required to evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees, as required by PRC-023-2 R1. The relay associated with this issue was at a substation at one end of a 230 kV line that is not part of a WECC Major Transfer Path and was also part of the Switch-on-to-Fault (SOTF) protective function. The minimum pickup value without voltage supervision would be 4.16 amps, such failure could prevent restoration of the line after a fault. However, as compensation, the average historical load on this line had been lower than the correct relay setting and no Misoperations occurred as a result of this relay setting error. WECC determined WACM had no prior relevant instances of noncompliance.
Mitigation	To mitigate this issue, WACM has: 1) corrected the relay setting associated with this issue; 2) performed a review to ensure that the PRC-023 control worksheet provided accurate information; and 3) changed the process for setting relays to update the PRC-023 control worksheet with the proposed settings before making changes to ensure the changes meet the criteria of the Standard. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019709	IRO-017-1	R2	Western Area Power Administration – Rocky Mountain Region (WACM)	NCR05464	4/10/2017 4/11/2017 4/17/2017	4/10/2017 4/13/2017 4/17/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible or confirmed violation.)	On May 18, 2018, WACM submitted a Self-Report stating that, as a Balancing Authority and Transmission Operator, it had a potential noncompliance with IRO-017-1 R2. Specifically, WACM did not enter two planned outages and one Forced outage into its Reliability Coordinator’s (RC’s) outage system, as defined in the RC’s outage coordination process. The first planned outage began and ended on April 10, 2017. The second planned outage began on April 11, 2017 and ended on April 13, 2017. The Forced outage began and ended on April 17, 2017, for a total of five days, for the three instances. The root cause of the issue was attributed to a lack of planning for unexpected situations during a project. Specifically, there were delays in the updates that WACM was making to its Coordinated Outage System (COS), which was in progress during the period of noncompliance, which required WACM to enter the outages manually. However, the entity did not have a plan in place to address such situations.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, WACM failed to perform the functions specified in its RC’s outage coordination process on three occasions, as required by IRO-017-1 R2. The planned and Forced outages were on WACM’s 115 kV system and are not part of a WECC Major Transfer Path. Such failure could result in outages that are not properly coordinated, and therefore could potentially result in an overload and loss of transmission and/or generation on the 115 kV system. Though WACM was aware of the updates to the RC’s and its own outages systems, it did not implement effective preventative controls to prevent the issue. However, as compensation, the RC was also notified in real-time about the Forced Outage. WECC determined WACM had no prior relevant instances of noncompliance.
Mitigation	To mitigate this issue, WACM has: 1) returned to compliance when each of the outages ended and were the details were logged in the system; and 2) implemented its Total Outage Application (TOA) which automatically processes between TOA and the RC’s COS to send outage information from WACM to the RC. TOA includes a field showing the COS outage number that coincides with the TOA outage program number. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019742	BAL-005-0.2b	R3	Western Area Power Administration – Rocky Mountain Region (WACM)	NCR05464	8/24/2017	8/25/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On May 18, 2018, WACM submitted a Self-Report stating that, as a Balancing Authority (BA), it was in potential noncompliance with BAL-005-0.2b R3. Specifically, on August 24, 2017 at 11:31 PM, one of the Western Area Power Administration (WAPA) regions and neighbor BA, requested that WACM begin Regulation Service because the other WAPA region had experienced a loss of generation. WACM then followed its process by programing its Supervisory Control and Data Acquisition (SCADA) to provide Regulation Service for the other WAPA region, but it failed to remove a scan inhibit tag. WACM's BA Operator correctly injected the pseudo tie data point with the other WAPA region into WACM's area control error (ACE), however the scan inhibit tag on that data point prevented it from entering into the WACM BA's ACE, which also prevented WACM from providing Regulation Service for the other WAPA region. The next morning on August 25, 2017 at 6:15 AM, the WACM BA Operator discovered the mistake and immediately removed the scan inhibit tag and was able to perform the required tasks. This issue began on August 24, 2017, when WACM did not provide Regulation Service and ended on August 25, 2017, when WACM began providing Regulation Service for the other WAPA region, for a total of six hours and 44 minutes. The root cause of the issue was attributed to less than adequate check of work. The WACM BA Operator did not check all data points for scan inhibit tags and after removing the tags should have verified that the data was still valid.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, WACM failed to ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a burden on the Interconnection or other BA Areas, when it did not remove a scan inhibit tag, as required by BAL-005-0.2b R3. The affected WAPA regions BA footprint mentioned above was 160 MW. Failure to provide regulation of the neighboring BA's ACE could have led to an imbalance in the neighboring BA area and a loss of the neighboring BA footprint totaling 160 MW. WACM did not have effective detective or preventative controls in place. However, as compensation, 160 MW is not significant to the BPS. As well, the WAPA region's System Operator monitored and took manual actions with its BA footprint to keep the ACE within +/- 5 MW for the period that the Regulation Service was not provided. There were no System Operating Limit exceedances nor contingency reserve requests during the period of noncompliance. WECC determined WACM had no prior relevant instances of noncompliance.
Mitigation	To mitigate this issue, WACM has: 1) removed the scan inhibit tag and began regulating the ACE; 2) conducted a staff meeting during which it reconstructed the incident, the root causes, and reviewed the defenses that would have mitigated each root cause' 3) created a lessons learned document; 4) brought new primary and alternate data source for entering ACE into WACM's SCADA via Inter-Control Center Communications Protocol (ICCP). This new data source would reduce the number of scan inhibit tags that the operator must remove; and 5) conducted a staff meeting to deliver the lessons learned presentation. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020398	COM-002-4	R1, R1.3, R1.4, R1.5, R1.6	Western Area Power Administration – Rocky Mountain Region (WACM)	NCR05464	7/1/2016	9/21/2018	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	During a Compliance Audit conducted from August 20, 2018 through August 31, 2018 WECC determined that WACM, as a Balancing Authority (BA) and Transmission Operator, was in potential noncompliance with COM-002-4 R1. WACM's documented communications protocols for its operating personnel that issued and received Operating Instructions did not specifically include all applicable field operating personnel. Specifically, WACM had Power Systems Operation Manuals that established procedures for the operation and maintenance of WACM's system. While these documents describe three-part communication aspects for receivers, they do not serve as a documented protocol and only included three-part communication protocols for certain Operating Instruction scenarios, such as switching, which did not account for all Operating Instructions. The Power Systems Operation Manual also does not include necessary details that are specified in the COM-002-4, specifically it did not include all operating personnel that receive Operating Instructions. WACM's definition for operating personnel that can receive Operating Instructions excluded field operating personnel, which are required in R1.3; it did not address burst Operating Instructions, as required by R1.4; it did not address the instances that required time identification, as required by R1.5; nor did it specify the nomenclature for Transmission interface elements and Facilities are specified. This issue began on July 1, 2016, when the Standard became mandatory and enforceable and ended on September 21, 2018, when WACM updated all its documented protocols to include all requirements of the Standard, for a total of 813 days. The root cause of the issue was attributed to WACM's misunderstanding about the definition of Operating Personnel which both receive and issue Operating Instructions, which led to incomplete documented communications protocols.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, WACM failed to appropriately include all applicable field operating personnel in its documented communications protocols for its operating personnel that issue and receive Operating Instructions that require its operating personnel that receive an oral two-party, person-to-person Operating Instruction to repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct or request that the issuer reissue the Operating Instruction; require its operating personnel that issue a written or oral single-party to multiple-party burst Operating Instruction to confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction, specify the instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification and specify the nomenclature for Transmission interface Elements and Transmission interface Facilities when issuing an oral or written Operating Instruction, as required by COM-002-4 R1. WACM operates 5,146 miles of transmission lines with voltages from 115 kV to 345 kV. WACM has 9,266 MW of generation in its BA footprint and 10,178 MW of load and transfers. A failure to develop required communication protocols could result in a miscommunication between the operator issuing an Operating Instruction and the receiver of the Operating Instruction, which could then result in an action or inaction on WAMC's system that could cause harm to the BPS. WACM did not implement preventative or detective controls. However, as compensation, this issue was largely administrative in nature. WACM performed extensive trainings on three-part communications, as required by COM-002-4 R2. WACM had a detailed manual for its trainings that addressed three-part communication and specified that WACM's Operators were instructed to only issue Operating Instructions to authorized personnel, which required additional training on three-part communications. WACM had certain documents that correctly addressed three-part communication, though its documented communications protocols did not meet the requirements of the Standard. WACM has trained the required personnel on how to correctly perform three-part communications, reducing risk of misunderstandings when issuing and receiving Operating Instructions, thereby reducing the risk to the BPS. WECC determined the entity had no prior relevant instances of noncompliance.
Mitigation	To mitigate this issue, WACM has: 1) updated its documentation for verbal communications protocols to addresses the requirements of the Standard, including: a. operating personnel that can receive Operating Instructions including field operating personnel; b. address burst Operating Instructions; c. address the instances that required time identification; d. specify the nomenclature for Transmission interface elements and Facilities are specified; and e. defined the term Operating Personnel, to include those that receive Operating Instructions and included three-part communications as those who can receive Operating Instructions. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2019021626	VAR-501-WECC-3.1	R2	Northern States Power (Xcel Energy) (NSP)	NCR01020	10/16/2018	10/18/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 10, 2019, PSCO, a Coordinated Oversight Program participant, submitted a Self-Log stating that, as a Generator Operator, it was in noncompliance with VAR-501-WECC-3.1 R2. NSP, Public Service Company of Colorado (PSCO) (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program and processed under Northern States Power (Xcel Energy) (NSP) (NCR01020). Xcel Energy reported that on October 16, 2018, Cherokee Unit #7 tripped due to loss of cooling water. Approximately, three minutes after the trip, the Power System Stabilizer (PSS) was disabled and an alarm was triggered. The Control Specialist on duty failed to recognize and acknowledge the PSS alarm due to an abnormally large number of alarms at the time, and assumed that the PSS was still enabled. While Unit #7 was restarted, the Control Specialist assumed that the PSS was enabled and due to an atypical startup process (that is not covered in an existing startup procedure), a step in the Cherokee Normal Operation Startup Procedure to verify the PSS status was omitted. The PSS remained disabled until another Control Specialist was reviewing the settings at the plant and discovered the disabled PSS. The Control Specialist immediately enabled the PSS, notified the PSCO Control Center, and logged the issue. The cause of the noncompliance was that Xcel Energy did not have sufficient internal controls in place for the Control Specialist to verify the status of the PSS after generation unit synchronization during normal operations or shift change. The noncompliance began on October 16, 2018, when PSS alarm was not recognized and enabled, and ended on October 18, 2018, when the PSS was enabled, the Control Center was notified, and the issue was logged.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Xcel Energy reported there was no equipment or reliability impact observed during period of noncompliance. The unit of issue is not a Blackstart resource and the plant reviewed log entries and plant historian data. Additionally, there was no unusual power oscillations observed during the time the PSS was disabled and the issue was detected by an internal control to review the PSS setting, limiting the period of noncompliance to 44 hours. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, Xcel Energy: 1) enabled and activated the disabled PSS; 2) reconfigured the current PSS status alarm to alert the Control Specialist that the PSS is disabled when the unit becomes synchronized; the modified alert will say "PSS NOT ENABLED AND UNIT SYNCHRONIZED"; 3) created plant startup procedure to cover the startup procedure used in this instance. This new procedure contains a step to verify that the PSS is enabled and active during synchronization. 4) added a new alarm to alert the Control Specialist that the PSS is enabled, but not active if the predetermined MW threshold is crossed after synchronization. The alarm will say "PSS ENABLED BUT NOT ACTIVE"; and 5) added a new process step to require a check of AVR/PSS status during shift changes.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019022097	PRC-005-6	R3.	Astoria Energy II LLC	NCR11112	04/01/2017	04/24/2019	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During an Off-site Compliance Audit conducted from March 20, 2019 through August 20, 2019, NPCC determined that Astoria Energy II LLC ("the Entity"), as a Generator Owner (GO), was in noncompliance with standard PRC-005-6 R3. More specifically, the Entity failed to perform the 18-month test of battery terminal connection resistance as prescribed by Tables 1-4(a-c) of the standard. The Entity owns four (4) applicable battery banks at its generating facilities: two (2) VRLA battery banks and two (2) NiCad battery banks, all of which were not specifically tested for their terminal connection resistance as prescribed by Table 1-4(b) and Table 1-4(c), respectively. Per the Implementation Plan, the Entity should have been 100% compliant by April 1, 2017. This noncompliance started on April 1, 2017, when the Entity failed to achieve 100% compliance for all its battery banks with respect to the aforementioned 18-month testing of terminal connection resistance, and ended on April 24, 2019, when the missed test was completed for all of the Entity's battery banks. The root cause of this instance of noncompliance is the Entity's belief that performing a battery discharge testing on an 18-month frequency obviated the need for performing the 18-month testing of battery terminal connection resistance.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The Entity owns four battery banks that operate the protection systems for its three generating facilities: two Combustion Turbines and one Steam Turbine, all of which are normally operated as a single Combined Cycle plant. The facilities are interconnected to a 345 kV substation owned by its host Transmission Owner (TO). The noncompliance consisted in the Entity's failure to achieve 100% compliance for its four battery banks with respect to the aforementioned test within the phase-in implementation timeline established by the standard. Failure to test battery terminal connection resistance may hinder detection of high connection resistance, which can cause abnormal voltage drop or physical damage from excessive heating during periods of high rates of discharge of a station battery. This noncompliance may in turn result in deterioration of battery performance and/or lack of proper DC voltage at a substation, which could cause protection systems to mis-operate or fail to operate when required in order to isolate electrical faults. However, the Entity reduced the risk of the noncompliance by performing battery discharge tests every 18 months, which is more frequent than the 3-6 years maximum intervals allowed by the standard for this test. Discharge tests consistently indicated that the batteries have been operating satisfactorily. The Entity's host TO designs and maintains its BES system in accordance with robust second contingency criteria. These criteria ensure that its system can sustain the non-simultaneous occurrence of two contingency events without violating established performance standards (i.e. thermal/voltage/stability) as well as preventing non-consequential load loss, all of which minimizes the potential degrading impact of noncompliance on the reliability of the interconnected system. The Entity's three generating facilities have a combined rated capacity of 570 MW. The combined average annual capacity factors for these generating units have been 57% (in 2016), 50% (in 2017) and 53% (in 2018). By comparison, the Entity's Reliability Coordinator (NYISO) carries required Operating Reserves of approximately 1965 MW and could have adequately compensated for potential unnecessary generation outages arising from this instance of noncompliance during normal operation or system contingency event for the duration of the noncompliance period. No harm is known to have occurred as a result of this instance of noncompliance. NPCC considered the Entity's compliance history and determined there are no prior relevant instances of noncompliance.
Mitigation	To mitigate the noncompliance, the Entity: 1. started performing the required testing of battery terminal connection resistance for all its applicable four (4) battery banks at the prescribed maximum intervals of 18 months; and 2. updated its battery inspection checklist to reflect the standard's time-based testing activity regarding measurements of battery terminal connection resistance.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019022098	PRC-019-2	R1.	Astoria Energy II LLC	NCR11112	07/01/2016	09/28/2016	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from March 20, 2019 through August 20, 2019, NPCC determined that Astoria Energy II LLC ("the Entity"), as a Generator Owner (GO), was in noncompliance with standard PRC-019-2 R1. The Entity failed to timely coordinate the voltage regulating system controls with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. Per the phased-in implementation plan of the Standard and Requirement, the above coordination was required by July 1, 2016 for two of the Entity's three generating facilities and by July 1, 2018 for the one remaining generating facility. This noncompliance started on July 1, 2016, when the Entity failed to perform the required coordination of voltage regulating system controls for two of its three generating facilities, and ended on September 28, 2016, when coordination activities were completed to bring these two units into compliance. On that same date, coordination of voltage controls for the Entity's third generating facility were also completed, ahead of its aforementioned July 1, 2018 deadline. The root cause of this instance of noncompliance was unforeseen long lead-times associated with securing the services of an engineering consultant to perform coordination of voltage regulating system controls as well as the complexity of required activities, which resulted in exceeding the completion timelines prescribed by the phased-in implementation plan of the Standard/requirement.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The Entity owns three generating facilities that are in scope of the standard: two Combustion Turbines and one Steam Turbine, all of which are normally operated as a single Combined Cycle plant. The facilities are interconnected to a 345 kV substation owned by its host Transmission Owner (TO). Failure to verify the coordination of voltage regulating system controls (to limit generator support within applicable equipment capabilities) and settings of the applicable Protection System devices and functions could cause an unnecessary trip thus reducing the amount of generation resources necessary to serve customer load under normal operation or contingency events. The coordination studies, when completed, did not result in any changes to existing settings of voltage regulating system controls for any of the Entity's generating units. Additionally, it is noted that the Entity's host TO designs and maintains its BES system in accordance with robust second contingency criteria. These criteria ensure that its system can sustain the non-simultaneous occurrence of two contingency events without violating established performance standards (i.e. thermal/voltage/stability) as well as preventing non-consequential load loss, all of which minimizes the potential degrading impact of noncompliance on the reliability of the interconnected system. The Entity's three generating facilities have a combined rated capacity of 570 MW. The combined average annual capacity factors for these generating units have been 57% (in 2016), 50% (in 2017) and 53% (in 2018). By comparison, the Entity's Reliability Coordinator (NYISO) carries required Operating Reserves of approximately 1965 MW and could have adequately compensated for potential unnecessary generation outages arising from this instance of noncompliance during declining system voltage events for the duration of the noncompliance period. No harm is known to have occurred as a result of this instance of noncompliance. NPCC considered the Entity's compliance history and determined there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1. completed the required coordination of voltage regulating system controls at its three generating facilities; and 2. incorporated work orders into its Maintenance Management System as reminders to ensure that future five-year verification of voltage regulating system controls are completed in accordance with the phased-in Implementation Plan of the Standard and Requirement.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019021019	MOD-032-1	R2.	NRG Northeast	NCR11709	10/28/2018	01/08/2018	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from July 12, 2018 through February 4, 2019, NPCC determined that NRG Northeast (NRG), as a Generator Operator (GOP) and Generator Owner (GO), was in noncompliance with MOD-032-1 R2. NRG failed to submit the required modeling data for all of its New York units to the NYISO, its Planning Coordinator (PC) and Transmission Planner (TP). NYISO requested modeling data in 2016 and 2017 and NRG failed to provide the data by the required dates. In 2016, NYISO requested modeling data by October 28, 2016, but did not receive the data until November 10, 2016 (nearly two weeks late). The following year, NYISO made a similar request for modeling data to be sent by October 27, 2017. NRG failed to provide the data until January 8, 2018 (more than two months late). The 2017 issue was partially the result of confusion surrounding data previously sent in a separate submittal made to the NYISO for Bowline Point generation (formerly in NRG Northeast) in September 2017. It was mistakenly believed that the Bowline Point email contained the data for all the NRG plants in NYISO, but it did not include the Arthur Kill, Astoria, or Oswego generators. The missing information was sent when NRG was notified of the missed information in January 2018. The two instances of this noncompliance occurred during two separate windows roughly a year apart. The first instance of noncompliance started on October 28, 2016, when NRG failed to submit the 2016 modeling data and ended on November 10, 2016, when the modeling data was sent to the TP and PC. The second instance of noncompliance started on October 27, 2017, when NRG failed to send modeling data to its TP/PC again the following year and ended on January 8, 2018, when data for all the NRG plants was submitted. The root cause of this noncompliance was a lack of internal controls to track data requests to ensure timely data submittals.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Specifically, the noncompliance could affect the Transmission Operator and Transmission Planner's ability to analyze the reliability of the system by failing to report modeling data in a timely and complete manner. The data has been requested annually since 2010. Between 2016 and 2018 (the years in question in this noncompliance), there were no changes to the modeling data submitted. Additionally, the plants involved had low capacity factors and were geographically dispersed. No harm is known to have occurred as a result of this noncompliance. NPCC considered NRG's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) submitted the 2016 and 2017 modeling data to its TP and PC; 2) changed the practice of tracking and tasking to focus on individual plant submissions instead of bundled into a single ISO submission task.

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019021050	MOD-025-2	R2	American Electric Power Service Corporation as agent for etc.	NCR00682	9/27/2018	10/1/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On February 3, 2019, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R2. The entity failed to submit a completed report to the Transmission Planner within 90 days of a Reactive Power verification as required by MOD-025-2 R2.2. On October 1, 2018, the entity discovered that the Reactive Power testing performed on June 28, 2018, at Flint Creek Unit 1 had not been sent to the Transmission Planner within 90 days. The entity discovered this noncompliance during a weekly review of the Reactive Power testing schedule which the entity used to confirm status of Reactive Capability verification testing. The 90 day period for notification of the Transmission Planner ended on September 26, 2018. The Flint Creek Unit 1 Reactive Power testing forms were submitted to the Transmission Planner on October 1, 2018. The root cause of this noncompliance was insufficient preventative controls to verify that all Reactive Power testing forms were submitted to the Transmission Planner within the 90 day requirement in MOD-025-2 R2.2. This noncompliance involves the management practices of verification and grid operations. Verification management is involved because the noncompliance arose from the entity's failure to ensure that certain testing information was shared with the Transmission Planner. Grid operations is involved because the failure to transmit Reactive Power testing forms impacts the Transmission Planner's situational awareness. This noncompliance started on September 27, 2018, when the entity was required to submit the Reactive Power testing form to the Transmission Planner and ended on October 1, 2018, when the entity submitted the Reactive Power testing form to the Transmission Planner.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by this noncompliance is that the Transmission Planner would not have accurate information on Reactive Power capability to use for its planning models to assess BPS reliability. The risk is minimized because of the short duration of the noncompliance; the Reactive Power testing form was submitted just four days late. Further minimizing the risk, the noncompliance was discovered as a result of a weekly internal review of reactive capability testing forms. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) executed the initial corrective action when they submitted the Reactive Power testing forms to the Transmission Planner on October 1, 2018; 2) performed an extent of condition by reviewing the entire reactive testing schedule throughout the MOD-025-2 phased implementation plan. At the end of the 2018 reactive capability testing season which was September 31, 2018, the entity had tested 76 out of 79 generating units per the MOD-025-2 implementation plan, with Flint Creek Unit 1 being the only incident where submittal to transmission planner exceeded 90 days; and 3) defined primary and secondary roles and responsibilities for MOD-025 to prevent recurrence. Roles were clarified and implemented which resulted in comprehensive oversight of all day to day operations involving MOD-025. The execution of this preventative control ensures that dedicated and qualified primary and support roles receive operational data, schedule updates and has access and authority to review and submit test forms electronically to the transmission planner. ReliabilityFirst has verified the completion of all mitigation activity.

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019021103	PRC-004-5(i)	R5	American Electric Power Service Corporation as agent for etc.	NCR00682	10/20/2018	11/15/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On February 14, 2019, the entity submitted a Self-Report stating that, as a Transmission Owner, it was in noncompliance with PRC-004-5(i) R5. The entity discovered that a Corrective Action Plan (CAP) had not been evaluated for applicability to other protection systems on November 15, 2018. The CAP was completed on October 10, 2018, 51 days following the Misoperation cause date of August 20, 2018. PRC-004-5 R5 requires that the entity shall determine a CAP and its applicability to other protection systems within 60 calendar days of determining the Misoperation cause. Although the CAP was completed on October 10, 2018, the entity did not evaluate the CAP for applicability to other protection systems until November 15, 2018, 87 days after the cause date, and 27 days later than required by the 60 day requirement in the standard. The root cause of this noncompliance was inadequate communication to verify that the CAP was being evaluated for applicability and insufficient internal transition processes to assure that PRC-004-5(i) compliance was not impacted by an employee transitioning between roles. Specifically, the individual that created the CAP report was transitioning into a new role. Additionally, the entity relied on a single employee to track this 60 day deadline. This noncompliance involves the management practices of workforce management and verification. Workforce management is involved because the entity failed to properly construct and manage a succession plan resulting in the CAP applicability evaluation being missed during an employee transition. Verification management is involved because the entity did not have an adequate internal control to assure that personnel executed the requirements of PRC-004-5(i) R5. This noncompliance started on October 20, 2018, the day after the entity was required to evaluate the CAP for applicability to other protection systems and ended on November 15, 2018, when the entity evaluated the CAP for applicability to other protection systems.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is the increased likelihood of future Misoperations of a similar nature due to the entity's failure to develop and evaluate applicability of a CAP. The risk is minimized because upon evaluating the applicability of the CAP to other protection systems, the entity determined that no other protection systems were impacted. Further minimizing the risk, the duration was limited to just 26 days, less than half of a cycle for the requirement. Lastly, the entity timely performed a misoperation analysis of the operation in question; the entity failed to timely document and evaluate the CAP. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) completed the CAP evaluation and determined that it was not applicable to other Protection Systems. Per the entity misoperation analysis policy, fault analysis personnel host weekly meetings with engineering to discuss CAPs involving settings, design or relay failure issues. The collaborative meetings are used to introduce, discuss and provide pertinent information necessary to engineering for determining whether a CAP is applicable elsewhere; 2) instituted a weekly meeting with all the fault analysts to review Automatic Equipment Investigation Report (AEIR) data to make sure that the database was up to date. AEIR provides fields for the description, a proposed completion date and actual completion date for each corrective action. AEIR is also utilized as an internal control to monitor and notify of upcoming due dates for CAPs. This control is a report that utilizes AEIR data and is ran on a bi-weekly basis that automatically calculates the CAP due dates as well as the evaluation due dates. That report is distributed to all Transmission fault analysts responsible for documenting all CAPs in AEIR; as well as their leadership to keep them apprised of open investigations and CAPs. The weekly meetings were a continuous extent of condition to review all PRC-004 reportable events going back to September 1, 2017 across the entity footprint to ensure no other reportable events missed the CAP development and applicability 60 calendar day window. These meetings began on November 19, 2018 and are ongoing. To date, no other events warranting PRC-004 investigation have been found to be late in the CAP evaluation phase; and 3) enhanced an existing control. Fault analysis personnel utilize SharePoint during weekly meetings with P&C Engineering to document CAPs and the subsequent evaluations of those CAPS to determine applicability. That SharePoint site will be exported into an excel file that can be then manually cross checked with an existing automated control report that utilizes data within AEIR to ensure both databases are updated in a timely manner. SharePoint is utilized so that cross department collaboration is easily achieved during the weekly meetings between fault analysts and engineering. There is also a SharePoint workflow process that allows managers to approve each CAP evaluation. The evaluation data is also imported into a word document form and saved into the corresponding AEIR record. The SharePoint site lists all open CAP evaluations with their unique AEIR ID numbers. Those ID numbers are subsequently populated in the automated control report that is ran on a bi-weekly basis to track upcoming due dates for CAPs and CAP evaluations. By comparing the two reports, the entity will be able to verify all CAPs have been accounted for and are up to date. This cross verification will also be communicated to all Transmission fault analysts and their leadership along with the bi-weekly control that is already distributed on a bi-weekly basis.

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019021103	PRC-004-5(i)	R5	American Electric Power Service Corporation as agent for etc.	NCR00682	10/20/2018	11/15/2018	Self-Report	Completed
			ReliabilityFirst has verified the completion of all mitigation activity.					

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019020979	MOD-025-2	R1	Delaware City Refining Company LLC	NCR11173	7/1/2018	6/7/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On January 17, 2019, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R1. The entity did not complete MOD-025-2 R1 verification of the real power capability and submission of results to the Transmission Planner (TP) for at least one of its two generators by July 1, 2018. During a 2018 internal audit, the entity reexamined the applicability of the Standard/Requirement to these two generators. This reexamination concluded that the Standard/Requirement was applicable to these generators because the 13.8 kV bus where the generators are connected and feed the oil refinery loads is also connected through transformers to the entity's 138 kV substation, and therefore, there is a potential for the generators to have an impact on the bulk power system's real and reactive power capability. Upon making this determination, the entity concluded that it should have completed the testing for at least one of these two generators before July 1, 2018. The root cause of this noncompliance was the entity's misinterpretation of the applicability of the Standard/Requirement. This root cause involves the management practices of grid maintenance because the substance of the requirement involves testing and maintenance, and workforce management, which includes providing education, training and awareness to employees. This noncompliance started on July 1, 2018, when the entity was required to verify and submit the real power capability for one of these two generators, and ended on June 7, 2019, when the entity verified and submitted the real power capability of Generator 2 (G2) to PJM.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by failing to timely provide data regarding generating capacity is that it could lead to inaccurate information in the generating models potentially causing a loss of generation. The risk is minimized in this case based on the following factors. First, the entity has a capacity factor of 38% and provides approximately 83 MVA to the directly connected oil refinery and just 60 MVA to the BPS, minimizing the potential impact of the risk. Second, the entity's nameplate capacity for G2 was already included in the TP's model and there was approximately an 8 MVA discrepancy between the nameplate capacity and the tested real power capability, further minimizing the potential impact of the risk in this case. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) updated the entity's NERC Compliance Tracking Tool to include scheduling and tracking for G2 real and reactive power testing; 2) completed real and reactive power testing that meets the requirements of MOD-025 3) updated the entity's procedure for Maintaining the Reliability Compliance Program for broader organizational focus on establishing the applicability of new and revised standards and requirements; and 4) submitted the real and reactive test data for the entity's G2 to PJM.

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019020980	MOD-025-2	R2	Delaware City Refining Company LLC	NCR11173	7/1/2018	6/7/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On January 17, 2019, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R2. The entity did not complete MOD-025-2 R2 verification of the reactive power capability and submission of results to the Transmission Planner (TP) for at least one of its two generators by July 1, 2018. During a 2018 internal audit, the entity reexamined the applicability of the Standard/Requirement to these two generators. This reexamination concluded that the Standard/Requirement was applicable to these generators because the 13.8 kV bus where the generators are connected and feed the oil refinery loads is also connected through transformers to the entity's 138 kV substation, and therefore, there is a potential for the generators to have an impact on the bulk electric system's real and reactive power capability. Upon making this determination, the entity concluded that it should have completed the testing for at least one of these two generators before July 1, 2018. The root cause of this noncompliance was the entity's misinterpretation of the applicability of the Standard/Requirement. This root cause involves the management practices of grid maintenance because the substance of the requirement involves testing and maintenance, and workforce management, which includes providing education, training and awareness to employees. This noncompliance started on July 1, 2018, when the entity was required to verify and submit the reactive power capability of at least one of its generators, and ended on June 7, 2019, when the entity verified and submitted the reactive power capability of G2 to PJM.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by failing to timely provide data regarding generating capacity is that it could lead to inaccurate information in the generating models potentially causing a loss of generation. The risk is minimized in this case based on the following factors. First, the entity has a capacity factor of 38% and provides approximately 83 MVA to the directly connected oil refinery and just 60 MVA to the BPS, minimizing the potential impact of the risk. Second, the entity's nameplate capacity for G2 was already included in the TP's model and there was approximately an 8 MVA discrepancy between the nameplate capacity and the tested reactive power capability, further minimizing the potential impact of the risk in this case. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) updated the entity's NERC Compliance Tracking Tool to include scheduling and tracking for G2 real and reactive power testing; 2) completed real and reactive power testing that meets the requirements of MOD-025; 3) updated the entity's procedure for Maintaining the Reliability Compliance Program for broader organizational focus on establishing the applicability of new and revised standards and requirements; and 4) submitted the real and reactive test data for the entity's G2 to PJM.

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019021239	PRC-019-2	R1	Delaware City Refining Company LLC	NCR11173	7/1/2016	7/30/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On March 11, 2019, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2 R1. During an internal audit in 2018, the entity discovered that it did not completely and appropriately document the coordination of voltage regulating controls, limit functions, equipment capabilities and protection system settings for four of its generators. Although the entity had these various pieces of information available, it did not document the relationships between these various pieces of information in the way described in Section G of PRC-019-2. (Section G describes acceptable forms of documented evidence to include various types of diagrams depicting the relationships between these settings.) Rather, the entity essentially relied on the vendors' expertise to ensure that these factors were appropriately coordinated. The root cause of this noncompliance was inadequate training and insufficient technical staff attention resulting in an incorrect interpretation of NERC PRC-019-2 requirements. Specifically, the entity did not effectively integrate subject matter experts into its process for producing compliant documentation. This noncompliance involves the management practice of workforce management. Workforce management is involved because the entity did not sufficiently involve subject matter experts in NERC Compliance implementation. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-019-2 R1 and ended on July 30, 2019, when the entity completed, documented, and dated the coordination of generator parameters as provided in PRC-019-2.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by failing to fully coordinate voltage regulating system controls with the applicable equipment capabilities and settings of the applicable Protection System devices and functions is that it could result in a generator falsely tripping or potential damage to the generator. The risk is minimized in this case based on the following factors. First, the entity's gross nameplate capacity is 378 MVA with a capacity factor 38%, providing MVA primarily to the directly connected oil refinery. Second, although the entity did not properly document the requisite coordination, the protective system studies by Schweitzer Engineering laboratories and the upfront Excitation System engineering by GE Exciter Engineers reduces the likelihood that the relevant settings were not properly coordinated. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) updated its NERC Compliance Tracking Tool to include the scheduling and tracking of the review and update of the voltage regulating controls, limit functions, equipment capabilities and protection system settings for the applicable generators so that the review and update occurs every five years; 2) updated its procedure for Maintaining the Reliability Compliance Program to get broader subject matter expert involvement in defining activities and proof of compliance documentation required for new and revised NERC Standards and Requirements; and 3) documented information for voltage regulating controls, limit functions, equipment capabilities and protective system settings for the applicable generators to show that the settings are appropriately coordinated.

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019021238	VAR-002-4.1	R2	NAES Corporation – Middletown Energy Center	NCR11831	2/7/2019	2/7/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On March 11, 2019, the entity submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with VAR-002-4.1 R2. During a monthly VAR-002 compliance check, the entity discovered that on February 7, 2019, at its Middletown Energy Center, it returned from a forced outage and synchronized the combustion turbine generator to the Bulk Electric System at 12:29 a.m. However, starting at 2:13 a.m. and ending at 4:33 a.m., the entity's system was above the 355 kV voltage schedule limit. Additionally, the entity failed to transmit the necessary communication required by VAR-002-4.1 R2. The entity failed to identify the voltage excursion in part because entity staff did not recognize a high voltage alarm which activates when voltage hits 354 kV, or 1 kV under the schedule limit. Entity staff were unable to recognize the alarm, which occurred at 12:22 a.m. on February 7, 2019, because it occurred 7 minutes prior to synchronization of the generator. During this time prior to synchronization and during startup, a number of other alarms occur as a product of the startup process, making it difficult to identify the high voltage alarm. Further, the alarm never reset because the voltage did not drop back below 354 kV, which allowed the alarm to remain active without signaling. Since the high voltage alarm had been previously acknowledged prior to synchronization, operations did not identify the elevated voltage and thus, did not adjust the generators or notify PJM accordingly. The root cause of the noncompliance was an insufficient startup process and inadequate employee training on synchronization following startup resulting in a failure to adjust the generator or notify PJM of the voltage excursion. Specifically, the entity's employees were unprepared to address and monitor the high voltage alarm during the startup process. This noncompliance involves the management practices of grid operations and workforce management. Grid operations management is involved because entity staff did not maintain situational awareness of operations during the startup process. Workforce management is involved because entity employees were not adequately prepared to handle synchronization during the startup process. This noncompliance started at 2:43 a.m. on February 7, 2019, the time by which the entity either had to bring the voltage back within the schedule or make the requisite notifications. The noncompliance ended at 4:33 a.m. on February 7, 2019, when the entity brought the voltage back into schedule.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by an entity failing to adhere to its voltage schedule is that it could increase the likelihood that the entity would be unable to respond to changes in voltage caused by reactive power demands and fail to provide voltage support to the BPS. This risk is minimized in this case based on the following factors. First, the voltage excursions above the scheduled limit of 355kV were small in magnitude, never exceeding PJM's Generator Default 345kV system limit of 357 kV. Second, the duration of the noncompliance was just one (1) hour and fifty (50) minutes, minimizing the amount of time that the potential harm could occur. No harm is known to have occurred. The entity has relevant compliance history. However, ReliabilityFirst determined that the entity's compliance history should not serve as a basis for applying a penalty because while the result of the prior noncompliance was arguably similar, the prior noncompliance arose from different causes.
Mitigation	To mitigate this noncompliance, the entity: 1) brought the voltage back within schedule; and 2) enhanced the alarm setpoints so that alarms will activate every 5 minutes if voltages are within 2kV of the schedule limit. This will ensure that this alarm will reinitiate if the voltage continues to stay outside of the voltage schedule until corrected. ReliabilityFirst notes that training was not necessary even though insufficient training was a contributing cause. Although insufficient training was noted as a contributing cause, the entity's solution to reinitiate the alarms will require the employee to acknowledge and address each alarm, resolving the issue of multiple alarms occurring during startup and ensure the voltage schedule is set and AVR is re-engaged.

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019021253	PRC-001-1.1(ii)	R3	New Covert Generating Company, LLC	NCR10295	12/18/2018	2/19/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On March 13, 2019, the entity submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with PRC-001-1.1(ii) R3. In June 2017, the entity contracted with Mitsubishi Hitachi power Systems (MHPS) to perform a turbine major inspection and upgrade for all three generating units, starting in October 2018. As part of preliminary checks, the entity asked MHPS if there would be any changes to relay settings during the project. MHPS assured the entity that there would be none. However, in February 2019, the entity received a report from MHPS detailing automatic voltage regulator (AVR) and relay parameter changes. MPHS had not coordinated these changes with PJM per the Standard/Requirement, nor had it made the entity aware that changes were being made. The root cause of this noncompliance was the lack of communication between MHPS and the entity during the upgrade work. This root cause involves the management practice of external interdependencies because MHPS was a contractor for the entity and the entity failed to appropriately manage risks associated with contracting the work. This noncompliance started on December 18, 2018, when the entity made the changes to relay settings without coordinating them and ended on February 19, 2019, when the entity notified both PJM and ITC Interconnection (ITCI) of the changes.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by failing to properly coordinate protection system changes is that the facilities could trip in unexpected ways or at unexpected times. The risk was mitigated in this case by the following factors. First, the changes to the relay settings were minor and had little to no impact on operations. Second, the entity coordinated the changes in a relatively short time after they were made, reducing the amount of time that the risk could have been realized. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) submitted the protective system changes to ITCI (Transmission Owner). ITCI replied that these changes were acceptable and understood that the same changes will occur on Unit 3 and Unit 1 during the upcoming major inspections; 2) sent another notification to PJM's Regional Compliance Manager (Transmission Operator and Balancing Authority). The entity also notified PJM the same settings changes would occur on Unit 3 and Unit 1; 3) requested that MHPS provide a Management of Change (MOC) program to prevent future incidents like this from occurring; and 4) implemented a process where MHPS will be required to complete the entity's MOC form where relay changes will not be implemented without entity management sign off of the applicable changes. This program will be implemented as part of the remaining two turbine and hot major inspections and upgrades.

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019022202	PRC-005-6	R3	Public Service Electric & Gas Company	NCR00896	3/1/2018	3/27/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On February 1, 2019, the entity submitted a self-log stating that, as a Distribution Provider and Transmission Owner, it was in noncompliance with PRC-005-6 R3. This possible violation was discovered during an entity NERC Standards and Compliance Group (NS&C) internal controls review of all entity Power Line Carrier System maintenance activities. Entity power line carrier systems which are part of the Bulk Electric System (BES) are maintained as per the NERC requirements specified in PRC-005-6 under Table 1-2 communication systems. The entity currently has a total of 36 power line carriers which have component attributes which either meet the definition of monitored or unmonitored and are maintained as per the specific requirements prescribed for each attribute. The potential violation occurred on the entity's 230kv tie line J-2210 which runs from the entity's Essex Switching Station to the Newark Bayonne Cogeneration Facility. The power line carrier communication system on this line met the attributes associated with an unmonitored communication system described in Table 1-2. Entity NERC Standard and Compliance Group (NS&C) performed an internal audit of all communication system NERC required maintenance and observed that on one occasion the J-2210 blocking carrier check maintenance was not tested within the specified NERC interval as outlined below: 1) Carrier check maintenance was performed on October 2, 2017 and again on March 27, 2018 which is outside the required 4 calendar month interval. Testing was due to be performed no later than February 28, 2018. This noncompliance involves the management practices of work management and reliability quality management as Newark Bay Cogeneration had a change of ownership during the noncompliance which resulted in a change in personnel who were responsible for the testing. This contributed to a communication lapse resulting in a loss of testing coordination between Newark Bay Cogeneration and the entity. That communication failure is a root cause of this noncompliance. This noncompliance began on March 1, 2018 when the entity was required to have performed the 4 calendar month interval testing on the power line carrier communication system, and ended on March 27, 2018, when the entity performed the overdue testing.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The potential risk of not timely testing the power line carrier communication system is the failure of that system which could negatively impact the BPS. The risk is minimized because of the short duration of the noncompliance. And, although the testing interval was exceeded, the carrier system was found to be fully functional when tested on March 27, 2018. The entity Relay Department continues to perform a full scheduled maintenance on this communication system which includes verification of proper equipment voltages and signal levels. This equipment had been tested within accepted specifications on the full maintenance schedule which was performed on October 10, 2017. The J-2210 230 kv line is a radial feed which solely provides an outlet for Newark Bay Cogen to export power and thus does not play a major role in the integrity of the BPS. It should be noted that during the time frame that the maintenance interval was exceeded, no misoperation of the J-2210 line occurred. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, the entity: 1) developed a coordinated testing schedule between Newark Bay Cogeneration and entity Relay Department which will not exceed the prescribed NERC testing interval. This coordinated testing schedule will help prevent recurrence by ensuring that the entity Relay Department confirms that testing is being done even in situations where plant ownership has changed; and 2) monitors the testing of the J-2210 line and places the testing dates on the NS&C Carrier log spreadsheet.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019022109	VAR-002-4.1	R1	Raven FS Property Holdings LLC	NCR11308	2/18/2018	2/19/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On September 30, 2018, the entity submitted a self-log stating that, as a Generator Operator, it was in noncompliance with VAR-002-4.1 R1. The Host Transmission Owner (TO) requested on February 19, 2018 that the Brandon Shores unit 2 control room operator (CRO) adjust the MVAR value, but when the CRO attempted to do so the reactive output kept coming back to its previous value. The TO was advised that the Automatic Voltage Regulator (AVR) prevented making the requested MVAR change, thereby satisfying R2.2 of VAR-002, and notification (an eDART ticket) was sent to the Transmission Operator (TOP) (PJM) within 30 minutes of discovering the AVR unresponsiveness, in compliance with R3 of VAR-002. Further investigation revealed that the AVR had inadvertently been put in the automatic-VAR control mode, instead of automatic-voltage control, when the unit was started-up several hours earlier at 19:08:50 on February 18, 2018. The automatic-voltage control mode was then selected and the eDART ticket was closed at 06:53:40 on February 19, 2018. This noncompliance involves the management practices of validation and verification. Raven did not validate and verify that the unit had been placed into automatic-voltage control when it started up on February 18, 2018. That failure to verify is a root cause of this noncompliance. This noncompliance began on February 18, 2018 when Raven started Brandon Shores unit 2 in automatic-VAR control mode instead of automatic-voltage control mode, and ended on February 19, 2019 when Raven put the unit back into automatic-voltage control mode.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk posed by failing to timely notify the TOP of a change in AVR status is that the TOP may assume that AVR is still automatically controlling voltage leaving it unaware of any abnormal system voltages that may have occurred. The risk is minimized because the violation existed for less than one day, the unit remained within its assigned voltage schedule the entire time, and there were no disturbances on the grid while the unit was in automatic-VAR control during the noncompliance. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, the entity operationally prevented the automatic VAR control mode on the day of the event, and it was permanently disabled in the scheduled outage of May, 2018. The AVR of Brandon Shores unit 1 (the sister unit) was checked, and it was found that the auto-VAR control mode had been disabled properly years ago.

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019021030	PRC-005-6	R3	Rolling Hills Generating, LLC	NCR00420	4/1/2017	4/1/2019	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On January 25, 2019, ReliabilityFirst determined that the entity, as a Generator Owner, was in noncompliance with PRC-005-6 R3 identified during a Compliance Audit conducted from November 26, 2018 through January 17, 2019. During the audit, ReliabilityFirst determined that the entity failed to provide evidence that it had performed certain maintenance and testing activities on (a) protection system station dc supply using vented lead-acid (VLA) batteries (Table 1-4a); and, (b) control circuitry associated with protective functions (Table 1-5). First, regarding the VLA batteries, ReliabilityFirst reviewed 12 samples. For two of those samples, the entity did not provide evidence that it completed all of the 18 calendar month activities. Specifically, the entity did not provide evidence that it (a) verified battery continuity; or, (b) verified battery terminal connection resistance. Additionally, the entity provided work orders for the following 18 calendar month activities, but did not provide sufficient evidence that these activities were actually completed: (a) verify float voltage of battery charger; and (b) inspect physical condition of battery rack. Second, regarding the control circuitry with protective functions, ReliabilityFirst reviewed 12 samples. For all 12 samples, the entity failed to provide evidence that it completed the following 6 calendar year activities: (a) verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device; and (b) verify electrical operation of electromechanical lockout devices. Notably, according to the Standard Implementation Plan, the entity was required to have completed these activities for only 30% of these components. The root cause of this noncompliance was insufficient maintenance practices by contractors and insufficient maintenance documentation by staff. This root cause involves the management practice of grid maintenance. This noncompliance started on April 1, 2017, when the entity was required to complete these activities and ended on April 1, 2019, when the entity completed the requisite maintenance and testing activities.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by failing to maintain and test protection system components is that those components may not operate properly when required. This risk was mitigated in this case by the following factors. First, despite having inadequate documentation for several required maintenance activities, the entity was still performing some regular maintenance, which mitigates some of the risk. Specifically, with respect to VLA batteries, the entity was performing the 4 calendar-month maintenance activities including verifying station dc supply voltage, inspecting electrolyte levels, and inspecting for unintentional grounds. Furthermore, the entity was performing some of the 18 calendar-month maintenance activities including verifying battery intercell or unit-to-unit connection resistance, and inspecting the cell condition of all individual battery cells where cells are visible, or measuring battery cell/unit internal ohmic values where the cells are not visible. Additionally, with respect to two other 18 calendar-month activities (i.e., verifying float voltage of battery charger and inspecting physical condition of battery rack), the entity had work orders including these activities as tasks to be completed. The work orders had an overall completion date listed, but did not have explicit indicators that these specific activities were completed. These facts support the entity's claim that this issue was primarily a documentation issue. Second, with respect to the control circuitry, the entity only missed one implementation interval because, at the time of the audit, the entity was required to have completed the 6 year maintenance activities on only 30% of its components. (The entity subsequently completed the maintenance activities for all of its control circuitry 2 years ahead of schedule.) Third, based on the entity's size and interconnections, the likelihood that the risk in this case would have anything more than a minimal impact on the BPS is low. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) retested control circuitry and documented testing results; 2) updated battery testing forms to include all required checks and a method to confirm completion; 3) completed the 18 month battery testing; 4) implemented compliance tracking software with escalation abilities; and 5) implemented an internal control process to verify that contractors' test reports adequately document all required testing.

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019022108	PRC-024-2	R1	Sapphire Power Marketing LLC	NCR00838	7/1/2017	9/12/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On September 30, 2018, the entity submitted a self-log stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R1. The Talen Energy NERC Group updates implementation plan progress monthly for all new NERC standards, and the Sapphire fleet reported 100% completion for PRC-024-2 in 2016. It was noticed when reviewing test reports on July 12, 2018 in preparation for a PRC-005 audit, however, that a frequency relay test report showed an over-frequency trip setting within the no-trip zone of PRC-024-2 Attachment 1. An investigation revealed that the Sapphire PRC-024-2 study had inadvertently been based on under-frequency settings only. Sapphire initially hired a contractor for PRC-024, but their work was unsatisfactory, and the work was taken in-house. This noncompliance involves the management practices of validation, verification, and external interdependencies. Talen hired a contractor to perform the review for PRC-024 but the contractor did not review over-frequency trip settings as part of that review. Talen's lack of oversight of the contractor performing the PRC-024 review is a root cause of this noncompliance. This noncompliance began on July 1, 2017 when Sapphire failed to timely review over-frequency trip settings as part of its PRC-024 review and ended on September 12, 2018 when Sapphire corrected all of the relay settings to become compliant with PRC-024.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk posed by failing to ensure that the frequency trips are outside of the no trip zone is that the units could be tripped early and not available to provide frequency support when necessary. This risk was minimized because Sapphire does not have blackstart capability and has an average net capacity factor of just 19%. Sapphire a 300 MW facility. Additionally, Sapphire had timely conducted the analysis for under-frequency settings pursuant to PRC-024. No under-frequency settings needed to get changed. Sapphire had just failed to conduct the analysis for over-frequency trip settings and only four over frequency settings needed changed. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, the entity: 1) confirmed that all Sapphire under-frequency relays (81U) are compliant with R1 of PRC-024-2 (no issues existed with under-frequency relays); 2) confirmed that Sapphire is compliant with R2 of PRC-024-2 (voltage protective relay settings). This exercise included reviewing NERC's proposed guidance document on the subject, which if issued by NERC will not affect the original analysis; 3) confirmed relay settings with GE; and 4) corrected all relay settings for Sapphire to meet PRC-024-2 requirements (four over frequency relay settings were changed).

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NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019022110	PRC-005-6	R3	Sapphire Power Marketing LLC	NCR00838	3/1/2018	3/28/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On September 30, 2018, the entity submitted a self-log stating that, as a Generator Owner, it was in noncompliance with PRC-005.6 R3. Table 1-2 of PRC-005-6 requires that a functionality test of unmonitored communications systems be performed at least every four calendar months. The directional comparison blocking (DCB) communications system at Sapphire's Newark Bay plant for their phase-distance (21) protection function is unmonitored and was tested on October 11, 2017, and next on March 28, 2018. The four-calendar-months deadline for the second test was February 28, 2018. The root cause of this situation was lack of clarity in the work order (W/O) for the communications system functional test. The W/O was programmed to be issued at the beginning of each quarter, to leave suitable margin to the 4-months deadline, but it stated that the work must be performed within 90 days. The task in question was performed near the beginning of Q4 2017, and the next time near the end of Q1 2018 to take advantage of an outage scheduled for that period. Plant personnel met the 90-day time-frame in both cases, but unknowingly exceeded the NERC-specified periodicity limit. This noncompliance involves the management practice of work management. The work order for the communications system functional test was poorly designed and allowed for plant personnel to miss timely completing a functional test. This noncompliance began on March 1, 2018, the date Sapphire was required to complete the functionality test of the unmonitored communications system per the four month interval, and ended on March 28, 2018 when Sapphire completed the overdue test.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The risk posed by this noncompliance is the unexpected failure of unmonitored communications systems which could reduce the reliability of the BPS. The risk is minimized because of the short duration of just seven days in comparison to a four month testing interval. Additionally, the communications system did not fail and functioned properly for the entire noncompliance, there were no faults in the neighboring PSEG system, and the plant did not trip when it should have kept running. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, the entity 1) completed the overdue test; and 2) committed to performing functional tests monthly in the future. Sapphire and Talen's NERC group met on August 14, 2018 with PSEG (the TO, which owns the opposing side of the communications system) to obtain their approval, since coordinated Sapphire-PSEG activity is needed for testing the Newark Bay side of the DCB system.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021841	MOD-025-2	R1	Alabama Power Company (APC)	NCR01166	07/01/2019	07/24/2019	Self-Log	Complete

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 16, 2019, APC submitted a self-log stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R1. APC failed to provide its Transmission Planner (TP) with verification of the Real Power capability for one applicable generating facility in accordance with the NERC Implementation Plan. On May 22, 2019, APC determined that it would be unable to meet the July 1, 2019 requirement for compliance with 100% of its applicable generating facilities for NERC Reliability Standard MOD-025-2, as specified in the NERC Implementation Plan. With 81 generators, APC successfully completed staged real power capability verification testing, according to MOD-025-2 Attachment 1, on all but one applicable generating facility, Lowndes County. Lowndes County is a co-generation facility comprised of one combustion turbine generator (CTG) and one steam turbine generator with a total facility rating of 112 MVA. APC planned to complete the required staged testing at Lowndes County following a planned outage in the spring of 2019. APC selected this testing schedule to ensure that the testing for MOD-025 would accurately capture and reflect the facility's real power capabilities following completion of the major generator outage work. APC's experience over the past 4 years of scheduling and performing similar tests indicated that two months was more than sufficient time to accommodate scheduling issues. On May 22, 2019, testing of the CTG at Lowndes County at the conclusion of the planned outage and prior to return to service indicated failure of the stator winding necessitating an extended outage through August 2019. On May 24, 2019, APC notified SERC Enforcement that a non-compliance would occur on July 1, 2019. This noncompliance started on July 1, 2019, when APC was required to be 100% compliant, and ended on July 24, 2019, when APC transmitted the results of testing to its TP. The root cause of the noncompliance was unanticipated equipment failure, which extended the outage past the NERC Implementation Plan 100% requirement on July 1, 2019.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. APC's failure to provide its TP with the Real Power Capability of the Lowndes County facility could have resulted in inaccurate long-term planning models thus impacting transmission planning requirements. However, this issue impacts long-term transmission planning models, which the TP updates annually, rather than real-time operations. Further, there was no reliability risk in the near-term horizons for having unverified Real Power capability for a unit that was not operating. Lowndes County has not been operational since April 2019. Lowndes County primarily serves the power and steam needs of an individual end-user. While the facility is included in day-ahead commitment models, APC does not consider the unit as dispatchable, and it is not considered a significant contributor to load or reactive support in the APC transmission system based on TP studies. No harm is known to have occurred. SERC considered APC's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, APC: 1) completed the required real power capability verification testing; and 2) transmitted the results of the testing to the Transmission Planner.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021842	MOD-025-2	R2	Alabama Power Company (APC)	NCR01166	07/01/2019	07/24/2019	Self-Log	Complete

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 16, 2019, APC submitted a Self-Log stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R2. APC failed to provide its Transmission Planner (TP) with verification of the Reactive Power capability for one applicable generating facility in accordance with the NERC Implementation Plan. On May 22, 2019, APC determined that it would be unable to meet the July 1, 2019 requirement for compliance with 100% of its applicable generating facilities for NERC Reliability Standard MOD-025-2, as specified in the NERC Implementation Plan. Lowndes County is a co-generation facility comprised of one combustion turbine generator (CTG) and one steam turbine generator with a total facility rating of 112 MVA. APC planned to complete the required staged testing at Lowndes County following a planned outage in the spring of 2019. APC selected this testing schedule to ensure that the testing for MOD-025 would accurately capture and reflect the facility's reactive power capabilities following completion of the major generator outage work. APC's experience over the past 4 years of scheduling and performing similar tests indicated that two months was more than sufficient time to accommodate scheduling issues. On May 22, 2019, testing of the CTG at Lowndes County at the conclusion of the planned outage and prior to return to service indicated failure of the stator winding necessitating an extended outage through August 2019. On May 24, 2019, APC notified SERC Enforcement that a noncompliance would occur on July 1, 2019. This noncompliance started on July 1, 2019, when APC was required to be 100% compliant and ended on July 24, 2019 when APC transmitted the results of testing to their TP. The primary cause of the noncompliance was unanticipated equipment failure which extended the outage past the July 1, 2019 100% NERC Implementation Plan requirement.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. APC's failure to provide its TP with the Reactive Power Capability of the Lowndes County facility could result in inaccurate long term planning models thus impacting transmission planning requirements. However, this issue impacts long-term transmission planning models, which the TP updates annually, rather than real-time operations. With 81 generators, APC successfully completed staged reactive power capability verification testing, according to MOD-025-2 Attachment 1, on all but one applicable generating facility, Lowndes County. Further, there is no reliability risk in the near-term horizons for having unverified Reactive Power capability for a unit that is not operating. Lowndes County has not been operational since April 2019. Lowndes County primarily serves the power and steam needs of an individual end-user. While the facility is included in day-ahead commitment models, APC does not consider the unit as dispatchable nor is it considered a significant contributor to load or reactive support in the APC transmission system based on TP studies. No harm is known to have occurred. SERC considered APC's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, APC: 1) completed the required reactive power capability verification testing; and 2) transmitted the results of the testing to the Transmission Planner. APC believes that current philosophy regarding the scheduling of tests to meet staged implementation thresholds for NERC Reliability Standards is valid, and that the issues experienced with Lowndes County that resulted in a delay in testing are unique, unusual and do not warrant a change in this philosophy. This assertion is supported by the successful completion of tests for 253 other generators across Southern affiliates in accordance with the threshold dates established in the implementation plan for MOD-025-2.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021996	PRC-002-2	R12	Dominion Energy South Carolina, Inc. (DESC)	NCR00915	02/27/2019	02/27/2019	Self-Report	Complete

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On August 1, 2019, DESC submitted a Self-Report stating that, as a Transmission Owner, it was in noncompliance with PRC-002-2 R12. DESC failed to, within 90-calendar days of the discovery of a failure of the recording capability for the fault recorder, either restore the recording capability, or submit a Corrective Action Plan to the Regional Entity and implement it. On June 6, 2019 during an internal audit, DESC discovered that a fault recorder at a substation was out-of-service for 91 days. During the internal audit, the audit team used a date calculator and determined that it took 91 days to repair and reinstall the equipment. On November 28, 2018, a fault recorder computer failed. DESC sent the fault recorder back to the vendor for repair. DESC did not inform SERC of a Corrective Action Plan because DESC intended to have the equipment received and reinstalled in time to meet the 90-day reinstallation deadline. Due to an error in calculating the required completion date, technicians believed they had until February 27, 2019 to reinstall the equipment, which was actually 91 days from the identification date. The business unit did not initially recognize the compliance issue. This noncompliance started on February 27, 2019, when DESC was required to return the fault recorder to service, and ended on February 27, 2019, when DESC returned the fault recorder to service. The primary cause of the noncompliance was a human error in mentally calculating the deadline.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. DESC's failure to restore the recording capability of the fault recorder within 90-calendar days of the discovery of the failure of the recording capability could have resulted in DESC's inability to conduct a forensic evaluation after a fault occurred. However, the fault recorder was out-of-service only one day longer than allowed by the Standard. DESC identified the performance issue with the fault recorder but simply miscalculated the required date to return the fault recorder to service. No harm is known to have occurred. SERC considered DESC's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, DESC: 1) returned the fault recorder to service; 2) provided reinforcement training to the Relay Applications and Relay Field Operations groups, which included a review of the Standard and emphasizing the importance of using a date calculator when determining prescriptive due dates; and 3) distributed an awareness "lessons learned" presentation to its Subject Matter Experts for ERO Standards to remind them to use a date calculator to determine prescriptive due dates.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021041	MOD-032-1	R2	Duke Energy Carolinas, LLC (DEC)	NCR01219	11/02/2018	02/08/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On February 8, 2019, Duke Energy Carolinas (DEC) submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-032-1 R2. DEC did not send a written notice that modeling data had not changed to its Transmission Planner (TP) and Planning Coordinator (PC) within the designated timeframe. During 2018, DEC compiled model changes for 68 units out of a total of 76 units applicable to the Standard. Prior to the deadline set by its TP and PC, DEC submitted a whole and complete record for the 68 units. Eight units out of the 68 units had no data changes for 2018. November 1, 2018, was the deadline to submit modeling data and/or written confirmation that data had not changed. However, DEC did not submit a notice that the eight units had no modeling data changes to its TP and PC. On February 2, 2019, DEC began a routine compliance review wherein this instance was discovered. On February 8, 2019, DEC sent written notification to its TP/PC that the eight units missing from its original submission had no data changes. This noncompliance started on November 2, 2018, when DEC failed to send its written notice of no changes to the modeling data for eight of its units to the TP/PC, and ended on February 8, 2019, when DEC sent written notification to its TP/PC that the eight units missing from its original submission had no data changes. The cause of this noncompliance was an inadequate procedure. DEC's procedure did not contain a requirement for DEC to send written notice to its TP and PC when modeling data had no changes since the last submission.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. DEC's failure to send written notification of no change for unchanged generators units could have led to delays in creating new models or model patches. However, DEC submitted all modified data, which minimized risk to system models. No harm is known to have occurred. SERC considered DEC compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate the noncompliance, DEC: 1) created a PlantView event reminder for each of the data submission dates to remind FHO that they should be receiving a request for data submission; 2) added a requirement to have a Compliance Action Program (CAP) item (CAP item added when a request is received and CAP item closed when data is sent); 3) revised Duke Energy Fossil Hydro Operation Technical Program for MOD-032 to add statement of "no change" to Fossil Hydro Operators (FHO) process; and 4) added the revised procedure to the document control program, which has a two year review cycle; a communication was made to all applicable staff; and training on the revised procedure was built into the training cycle for the future.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019020897	FAC-013-2	R4	Duke Energy Progress, LLC (DEP)	NCR01298	01/01/2018	10/15/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 2, 2019, Duke Energy Progress (DEP) submitted a Self-Report stating that, as a Planning Coordinator, it was in noncompliance with FAC-013-2 R4. DEP failed to 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. On November 1, 2017, DEP failed to conduct simulations, and thus, was unable to document simulation results. DEP primarily relies on the SERC Annual Summer Future Year Study Report as the basis for its analysis, which DEP then combines with internal studies results for its final reports. In 2017, the Transmission Planning Lead Engineer failed to notice that SERC had published the Annual Summer Future Year Study Report. The publishing of the SERC report was the trigger for DEP to begin its process, and by missing the trigger, the process never started. On October 8, 2018, while preparing for the 2018 Transfer Capability process, DEP discovered that the 2017 Transfer Capability report did not exist. On October 15, 2018, DEP completed its 2017 Transfer Capability report, and, on October 16, 2018, DEP distributed the 2017 report to all applicable parties. This noncompliance began January 1, 2018, when DEP failed to complete its 2017 Transfer Capability assessment, and ended on October 15, 2018, when DEP completed its 2017 Transfer Capability report. The cause of this noncompliance was a combination of a human error issue and a lack of internal control. Specifically, the Transfer Capability process relied entirely on a single individual to recognize the notice from SERC, and, when the individual failed to recognize the notice, there was no internal control to catch the error.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. DEP's failure to conduct simulations and document an assessment based on those simulations as required, could have caused a transfer limit to have been ignored, which could burden a neighbor's system. However, DEP had secondary mechanisms, such as using the SERC studies, to track and limit transfer for all but one of its neighbors. Moreover, for the one neighbor without secondary mechanisms, DEP had historical transfer limits which it respected, further limiting the possible impact. No harm is known to have occurred. SERC considered DEP's and its affiliates' compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, DEP: 1) completed DEP's FAC-013-2 2017 Transfer Capability Assessment; 2) sent DEP's completed FAC-013-2 2017 Transfer Capability Assessment to appropriate stakeholders; and 3) established a DEP annual Recurring Evidence Schedule in DEP's Enterprise Compliance Application to remind the DEP Transmission Planning SME (functioning as the Planning Coordinator) to complete the FAC-013-2 R4 and R5 activities by November 1 of each calendar year.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017016742	FAC-009-1	R1	Entergy	NCR01234	03/16/2011	06/02/2016	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 3, 2017, Entergy submitted a Self-Report stating that, as a Transmission Owner, it was in noncompliance with FAC-009-1 R1. Entergy did not rate one line conductor in accordance with its Facility Rating Methodology (FRM). On March 16, 2011, Entergy approved and released the Facility Rating Workbook for the dual circuit 230 kV Carlyss to Rose Bluff transmission line. Entergy determined the conductor Rating using a basis of 130 degrees Celsius, which would have been acceptable for slack lines or used to determine the emergency Rating; however, the conductor should have been determined using a basis of 100 degrees Celsius. Entergy incorrectly determined that the conductor Rating was 797 MVA, but the limiting element (line bay bus), limited the Facility Rating to 405 MVA, which was the figure Entergy entered into its operational models. On May 20, 2011, Entergy upgraded the Facility's line bay bus and revised the Facility Rating Workbook to show the conductor as the most limiting element. Therefore, Entergy adopted the recorded conductor Rating of 797 MVA as the Facility Rating. On May 31, 2016, in connection with a modification project, Entergy processed an energization notice for a derate of the 230kV Carlyss to Rose Bluff transmission line. Upon reviewing the Facility Rating Workbook, Entergy discovered that it had not determined the Rating of the 230kV circuit in accordance with its FRM. Entergy found it had established the normal Rating of the Carlyss to Rose Bluff line to be equal to the emergency Rating. As a result, Entergy had previously determined the normal Rating as 1035 Amps (797 MVA) rather than 860 Amps (685 MVA), an error of 16%. Entergy conducted an extent-of-condition assessment by reviewing Facility Ratings for 68 Facilities that were identified to have an Aluminum Conductor Alloy Reinforced (ACAR) or an All-Aluminum type conductor with a Rating temperature of 130 Celsius or no Rating temperature listed. Entergy reviewed all of those Facility Rating Workbooks to determine if the Rating temperature used to calculate the normal conductor Rating was correct and identified no incorrect Ratings. This noncompliance started on March 16, 2011, when Entergy approved the incorrect Facility Rating Workbook, and ended on June 2, 2016, when the conductor Rating was corrected. The root cause of this noncompliance was a lack of training and experience, and a contributing cause was an internal control failure, both of which led to the incorrectly documented Facility Rating. An employee chose the wrong Rating from a list of alternate ACAR conductor Ratings and the reviewer and approver did not identify the incorrect conductor Rating.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Failure to establish correct Facility Ratings could result in improper operational planning and operation of equipment causing damage or reduced lifetime of Facilities. However, in this case, Entergy failed to properly calculate the normal Rating of one transmission line, but did correctly determine an emergency Rating. Entergy used the correct emergency Rating in its planning and in its Energy Management System, so operators were aware of any exceedances of the emergency Rating and would have taken corrective action. Maximum load in the last year did not exceed 292 MW, less than 47% of the corrected normal Rating. In addition, normal power flow places the Carlyss to Rose Bluff line downstream of the PPG to Rose Bluff line. Entergy had determined the correct Facility Rating for the PPG to Rose Bluff line and it is more limiting than the Carlyss to Rose Bluff line. Under normal operation, the PPG to Rose Bluff line limits the power flow through the Carlyss to Rose Bluff line. No exceedance occurred. No harm is known to have occurred. SERC determined that Entergy's FAC-009-1 R1 and FAC-008-3 R6 compliance history should not serve as a basis for aggravating the penalty. One was a 2009 issue, and the other six issues would have been consolidated into two separate issues (one 2013 and one 2014) had they been processed today. Entergy's compliance history with FAC-008-3 R6 and FAC-009-1 R1 does not represent conduct such that it warrants a penalty.
Mitigation	To mitigate this noncompliance, Entergy: 1) corrected the Facility Rating Workbook; 2) performed the extent-of-condition assessment, which revealed that the condition was isolated to the one incident; and 3) coached and trained personnel on reporting Rating discrepancies and when to apply the 130 degree Celsius temp rating. Entergy mitigated the internal control failure in relation to a later violation (NERC ID SERC2017016879). Specifically, Entergy: 1) formalized the review/approval process into a full procedure; 2) tracked the review/approval process in a ticketing system; and 3) performed after-the-fact reviews to ensure the Facility Rating Workbook Ratings were accurate.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021979	PRC-005-6	R5	Owensboro, KY Municipal Utilities (OMU)	NCR01290	10/05/2017	06/18/2019	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from July 8, 2019 to July 12, 2019, SERC determined that OMU, as a Generation Owner and Transmission Owner, was in noncompliance with PRC-005-6, R5. OMU failed to demonstrate efforts to correct identified Unresolved Maintenance Issues. On October 5, 2017, the test record for the 138kV circuit breaker 150-766 current transformer (CT) showed an 11% deviation on the C-phase 2, 4, 6 Y/2, 4, 6 X components and a 6% deviation on the C-phase 1, 3, 5 Y/1, 3, 5 X components. OMU's documented procedure required that deviations exceeding +/-5% receive further investigation. On June 18, 2019, upon learning from the SERC audit team of the failing test record, OMU dispatched a crew to retest the C-phase 2, 4, 6 Y/2, 4, 6 X components and found the CT had a 1.01% deviation. The OMU Delivery Operations Manager determined C-phase 1, 3, 5 Y/1, 3, 5 X components to be a rounding error within the excel document due to the cells in the document rounding to two decimal places instead of three. On September 12, 2019, OMU completed an extent-of-condition evaluation by performing an inventory of all BES protection system elements and found no additional instances of noncompliance with PRC-005-6, R5. This noncompliance started on October 5, 2017 when OMU failed to demonstrate efforts to correct identified Unresolved Maintenance Issues, and ended on June 18, 2019, when OMU resolved the maintenance issue. The primary cause of this noncompliance was the lack of an effective internal control to verify data before acceptance.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. OMU's failure to correct identified Unresolved Maintenance Issues concerning the 150-766 C-phase CT could have caused the relay protection system to misoperate. However, OMU's substation and its associated transmission lines operate at more than 100kV, but the substation and its associated transmission lines meet the criteria for exclusion from the BES, per exclusion E3 – Local networks. Therefore, a misoperation would have minimal impact on the BES. Additionally, OMU did not experience a loss of load, generation or transmission elements, and did not experience any system disturbances, protection system operations or misoperations prior to, during, or as a result of the Unresolved Maintenance Issue. No harm is known to have occurred. SERC considered OMU's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, OMU: 1) retested CT 150-766 and verified (1.01%) that it was within +/- 5% tolerance; 2) performed an extent-of-condition evaluation of all BES test records to determine if required minimum maintenance and testing activities were completed within the maximum intervals specified in PRC-005-6; 3) trained substation and plant maintenance personnel on Protection System Maintenance Program maintenance activities; 4) modified test sheets to include supervisory and management approval. If an unresolved maintenance activity is identified, supervisory approval will be withheld and a trouble order is submitted in the mobile management system. The test record will not be approved until the maintenance activity is resolved. All unresolved tickets will be forwarded to the Operations Manager for review. Any maintenance activities remaining unresolved for more than 15 business days will be forwarded to the Director of Delivery for review. Status updates on all resolved and unresolved tickets will be reviewed quarterly at OMU's SERC team meeting. Following the Operation Manager's approval of a BES test record, the record will be sent to the Operations System Supervisor for document retention; and 5) revised its Internal Compliance Program to require quarterly meetings with topic experts to discuss completed and pending unresolved maintenance activities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021980	PRC-005-2	R3	Owensboro, KY Municipal Utilities (OMU)	NCR01290	04/01/2015	07/18/2019	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from July 8, 2019 to July 12, 2019, SERC determined that OMU, as a Generation Owner and Transmission Owner, was in noncompliance with PRC-005-6 R3. OMU failed to provide sufficient evidence to show that it maintained its Vented Lead Acid (VLA) batteries that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-4(a) of PRC-005-6, R3. SERC later determined that the noncompliance extended back to PRC-005-2. OMU failed to perform resistance testing, per PRC-005-2 Table 1-4(a), for the VLA batteries installed in the OMU Plant 2 Relay House at the Elmer Smith Station (ESS). All other battery checks were completed, such as voltage and water level. OMU also failed to meet the 18 month maintenance interval for resistance testing on the VLA batteries installed inside the ESS. OMU has 224 Bulk Electric System (BES) components and only two BES batteries. These two instances equated to a 100% failure rate. OMU owns and operates two coal units at the ESS with a total generation capacity of 505.5 MVA nameplate that connect at 138 kV. The net MVA rating for unit 1 is 135 MVA with a previous 12-month capacity factor of 55.28%. The net MVA rating for unit 2 is 261 MVA with a previous 12-month capacity factor of 50.36%. On July 26, 2016, the ESS batteries 18 month inter-cell resistance readings were performed and documented. The batteries were due for their next 18-month test no later than January 27, 2018. However, the 18-month inter-cell resistance test did not occur until July 10, 2018 (164 days late). No issues were identified on the 2016 or 2018 tests. The plant control room monitors the ESS batteries for alternating current, main and reserve charger trouble, ground condition, and under-voltage. On July 18, 2019, the Plant 2 Relay House batteries were tested. No previous resistance readings had been recorded. The test revealed that connections between cells 5 and 6 had high resistance readings. Substation electricians disconnected, cleaned the connections, and then retested the batteries. Cleaning the connections resolved the high resistance issue. The Plant 2 Relay House battery voltage was continuously monitored by OMU system operators 24 hours a day seven days a week via Supervisory Control and Data Acquisition (SCADA) with priority alarming for low voltage alarms. Further investigation determined the batteries' last connection resistance test was performed on February 7, 2001. On September 12, 2019, OMU completed an extent-of-condition (EOC) evaluation of all BES test records to determine if the required minimum maintenance and testing activities were completed within the maximum intervals specified in PRC-005-6. The EOC determined there were no additional instances of noncompliance. This noncompliance started on April 1, 2015, when OMU failed to maintain its VLA Batteries within the time-based maintenance program, and ended on July 18, 2019, when OMU completed the resistance testing. The causes of this noncompliance were the lack of an effective internal control, e.g., a secondary reviewer and approver, to verify Protection System Maintenance Plan (PSMP) maintenance activities were completed and verified, and the lack of training at the substation electrician level.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. OMU's failure to complete all the required battery testing could have caused its Protection System devices to not operate properly. However, the battery voltage was continually monitored by OMU personnel via SCADA. Additionally, the voltage alarms were set as a priority and required immediate notification to substation personnel, which have a 30 minute response time requirement. No harm is known to have occurred. SERC considered OMU'scompliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, OMU: 1) completed battery terminal connection resistance testing at Plant 2 Relay House; 2) completed battery intercell or unit-to-unit connection resistance testing at ESS; 3) performed an EOC evaluation of all BES test records to determine if required minimum maintenance and testing activities were completed within the maximum intervals specified in PRC-005-6; 4) completed training for Substation and Plant Electricians on PSMP maintenance activities; 5) modified test sheets to include supervisory and management approval. If an unresolved maintenance activity is identified, supervisory approval will be withheld. The test record will not be approved until the maintenance activity is resolved. All unresolved tickets will be forwarded to the Operations Manager for review. Any maintenance activities remaining unresolved for greater than 15

	business days will be forwarded to the Director of Delivery for review. Status updates on all resolved and unresolved tickets will be reviewed quarterly at OMU's SERC team meeting. Following the Operation Manager's approval of a BES test record, the record will be sent to the Transmission and Distribution Operations System Supervisor for document retention; and 6) revised its Internal Compliance Program to require quarterly meetings of topic experts to discuss completed and pending BES maintenance and testing activities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019022192	TOP-001-4	R13	South Carolina Public Service Authority (SCPSA)	NCR01312	08/12/2019	08/12/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 9, 2019, SCPSA submitted a Self-Report stating that, as a Transmission Operator, it was in noncompliance with TOP-001-4, R13. SCPSA failed to ensure that it performed a Real-time Assessment (RTA) at least once every 30 minutes. SCPSA schedules its Real-time Contingency Analysis (RTCA) to execute every 10 minutes. On August 12, 2019, at 11:08 a.m., the RTCA solved successfully. Ten minutes later, at 11:18 a.m., the RTCA failed to solve. The system issued a visual alarm that noted "diverged" to the System Operators via the Energy Management System (EMS) alarm display, which indicated the RTCA had failed to solve for 10 minutes. The System Operator did not notice the visual alarm until 11:52 a.m. Once the visual alarm was detected, the System Operator initiated the backup process that included notification to the Reliability Coordinator (RC) and the EMS Engineering Support Staff. The System Operator also initiated a manual execution of RTCA at 11:54 a.m., which resulted in a successful solved solution. Thus, SCPSCA failed to complete a RTA for approximately 46 minutes. SCPSA also has paging notifications to alert personnel when the RTCA fails to solve. The pages rely on non-redundant servers that were unavailable during the period of noncompliance due to planned maintenance activities. As a result, Energy Control Center (ECC) supervision and EMS support personnel were also unaware of the failure until 11:52 am. This noncompliance started on August 12, 2019, at 11:39 a.m., when SCPSA failed to conduct a RTA within 30 minutes of its last successful RTA completion, and ended on August 12, 2019, at 11:54 a.m., when SCPSA conducted a RTA. The root cause of this noncompliance was inadequate internal controls. Specifically, SPCSA did not have an audible alarm to alert the System Operator when the RTCA failed to solve, and the servers were unavailable for paging notifications.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Failure to ensure that a RTA is completed may result in instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection. However, immediately after the event, SCPSA contacted the RC to verify it conducted a RTA of the entire VACAR system during the time of SCPSA's RTA failure, which the RC confirmed. The RC's RTCA monitors for loss of lines, transformers, and generating facilities. SCPSA's RTCA monitors for loss of lines, single bus, transformers, and generating facilities. Also, SCPSA successfully completed the RTA only 16 minutes after the expiration of the allowed 30 minute period to conduct a RTA. No harm is known to have occurred. SERC considered SCPSA's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, SCPA: 1) implemented an audible EMS alarm for RTCA failures; 2) developed a Quick Reference Guide for the System Operators that outlines the operating process for what to do in the event of an RTCA failure; 3) changed the paging notifications to by-pass the non-redundant servers and continue to send the notifications to ECC supervision and EMS support personnel when the servers are down for maintenance; 4) included all System Operators in the paging notifications; and 3) conducted training for all its System Operators on the RTA process and actions required when the RTCA fails.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019022111	MOD-025-2	R1, P1.2	Tampa Electric Company	NCR00074	08/23/2016	11/09/2018	Self-Report	Complete

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On August 26, 2019, TEC submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R1.2. TEC failed to submit the results of seven staged Real Power capability tests to the Transmission Planner (TP) within 90 days as required. On July 23, 2018, during a documentation review, TEC discovered that it failed to meet the July 1, 2018 deadline to complete MOD-025 R1, P1.2 Real Power capability testing of at least 80% of TEC's applicable Facilities. TEC performed staged tests on the seven combustion turbines (Bayside CT1A, CT1B, CT1C, CT2A, CT2B, CT2C, and CT2D) between May 24, 2016 and October 14, 2016. However, TEC did not formally communicate the test results to the TP until November 9, 2018, 808 days late. TEC performed an extent of condition review of all 23 generators, and only found it had not submitted the seven Real Power capability tests to the TP within 90 days. The seven combustion turbines represent 30 percent of the total fleet of generators that are subject to MOD-025. This noncompliance started on August 23, 2016, when TEC failed to notify its TP with the Real Power capability test results, and ended on November 9, 2018, when TEC notified the TP of the Real Power capability test results. The cause of this noncompliance was that the procedure did not adequately define individual roles and responsibilities when conducting tests, tracking the evidence, and reporting test results.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). TEC's failure to notify the TP of the Real Power capability test results could have caused the TP to have improper data in the TP planning models, which could have impacted the reliability of the BPS. This risk was reduced because TEC's differences between the MOD-025 Real Power capability test results and the data used in planning models for the seven generators were minimal and had no material impact on the planning studies. The seven combustion turbines represent 30 percent of the total fleet of generators that are subject to MOD-025. No harm is known to have occurred. SERC considered TEC's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, TEC: 1) emailed TP the Real Power capability test results for BPS CT1 (A, B, C) and BPS CT2 (A, B, C, D); 2) performed an extent-of-condition review; 3) updated the Energy Services (ES) Compliance Handbook to clarify the timing requirement and handling of the notification to the TP; 4) performed a preventative control review of the Compliance Plan and future schedule; and 5) performed preventative control communication and training to Station Engineers regarding changes to MOD-025 procedure in the ES Compliance Handbook.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019022112	MOD-025-2	R2 Part 2.2	Tampa Electric Company	NCR00074	08/23/2016	11/09/2018	Self-Report	Complete

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On August 26, 2019, TEC submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R2.2. TEC failed to submit the results of seven staged Reactive Power capability tests to the Transmission Planner (TP) within 90 days as required. On July 23, 2018, TEC discovered during the review of data that it gathered to meet the July 1, 2018 deadline to complete MOD-025 R2.2 Reactive Power capability testing of at least 80% of TEC's applicable Facilities, that it did not submit the results of seven staged Reactive Power capability tests to the Transmission Planner (TP) within 90 days as required by MOD-025-2, R2 Part 2.2. TEC performed staged tests on the seven combustion turbines (Bayside CT1A, CT1B, CT1C, CT2A, CT2B, CT2C, and CT2D) between May 24, 2016 and October 14, 2016. However, TEC did not formally communicated the results to the TP until November 9, 2018, 808 days late. TEC performed an extent of condition review of all twenty-three generators, and only found it had not submitted the seven Reactive Power capability tests to the TP within 90 days. The seven combustion turbines represent 30 percent of the total fleet of generators that are subject to MOD-025. This noncompliance started on August 23, 2016, when TEC failed to notify the TP with the Reactive Power capability test results and ended on November 9, 2018, when TEC notified the TP of the Reactive Power capability test results. The cause of this noncompliance was that the procedure did not adequately define individual roles and responsibilities when conducting tests, tracking the evidence, and reporting test results.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). TEC's failure to notify the TP of the Reactive Power capability test results would cause the TP to have improper data used in the TP planning models potentially impacting the reliability of the BPS. This risk was reduced because TEC's differences between the MOD-025 Reactive Power capability test results and the data used in planning models for the seven generators were minimum and had no material impact on the planning studies. The seven combustion turbines represent 30 percent of the total fleet of generators that are subject to MOD-025. No harm is known to have occurred. SERC considered TEC's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, TEC: 1) emailed TP the Reactive Power capability test results for BPS CT1 (A, B, C) and BPS CT2 (A, B, C, D); 2) performed an extent of condition review; 3) updated the Energy Services (ES) Compliance Handbook to clarify the timing requirement and handling of the notification to the TP; 4) performed a preventative control review of the Compliance Plan and future schedule; and 5) performed preventative control communication and training Station Engineers regarding changes to MOD-025 procedure in ES Compliance Handbook.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
FRCC2019021671	TOP-001-4	R9.	Tampa Electric Company (TEC)	NCR00074	5/10/2019	5/10/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed noncompliance.)	On June 11, 2019, TEC submitted a Self-Report stating that, as a Balancing Authority (BA) and Transmission Operator (TOP), it was in noncompliance with TOP-001-4 R9. This noncompliance started on May 10, 2019, when TEC failed to provide advance notification to the Reliability Coordinator (RC) and known impacted interconnected entities of a planned outage and ended on May 10, 2019, when the planned outage was over. The instance was limited to a single 84-minute period in which data from the remote terminal unit (RTU) was interrupted three times: once for 19 minutes, and twice for 17 minutes as the RTU was removed from service to perform the outage work. This instance of noncompliance was discovered on May 13, 2019 when the Grid Operations engineer performed a meter error check and noticed some inconsistent data points from the Bayside #1 RTU. Follow-up conversations with both the Bayside Generator Operator (GOP) and TEC's RTU group revealed that the Bayside RTU had been removed from service to support the outage maintenance of Bayside #1 on May 10, 2019. An extent of condition was performed, and this was identified as a single incident in which TEC as the BA and TOP did not notify the RC and known impacted interconnected entities of a planned outage as required. The cause for this noncompliance was a miscommunication among all internal groups involved that the scope of work to be performed would require an outage of one of four Bayside RTUs; therefore, the procedure was not applied.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. TEC's failure to notify the RC of the planned outage could have caused the RC to take actions based on the loss of telemetry data from the RTU's during the outage impacting the reliable operation of the BES. The risk was reduced because the Energy System Operator (ESO) was in contact with the GOP and the units involved were intentionally removed from automatic generation control (AGC) before the planned outage so the work could not affect unit outputs. Furthermore, the scope was limited to three short interruptions of data from a single RTU (once for 19 minutes and twice for 17 minutes), and the data quality codes of the Inter-Control Center Protocol (ICCP) used to transmit the RTU data provided adequate notice to the RC and interconnected entities that the data was invalid during these periods. ICCP provides quality codes to alert data users when data points are not valid. These quality codes by themselves are the accepted means of communicating telemetry data interruptions during unplanned outages. Therefore, even though TEC did not formally communicate the planned outage, the RC and all the interconnected entities had notice during the brief outages that the data was not valid. The Region determined that the Entity's compliance history should not serve as a basis for applying a penalty. No harm is known to have occurred as the RTU outage had no impact on unit output or on system operations.
Mitigation	To mitigate this noncompliance, TEC: 1) Performed an Extent of Condition analysis 2) Performed a Root Cause Analysis; 3) Updated the BES Outage Notification Procedure for increased clarity on the notification and communication of planned RTU outages; 4) Trained ESO and Grid Ops Next Day Planner on the BES Outage Notification Procedure; 5) Created a procedure for RTU Outages which will be shared with field personnel annually; 6) Shared Substation Operations group's procedure with field personnel; and 7) Created an internal control via an event driven task to all TEC GOs/GOPs to clearly communicate if the planned work will result in an RTU outage to the TOP.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019022208	VAR-002-4.1	R2	Tilton Energy, LLC's (Tilton)	NCR11014	06/10/2019	06/10/2019	Self-Report	12/31/2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 13, 2019, Tilton submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with VAR-002-4.1 R2. Tilton failed to maintain the generator voltage schedule provided by the Transmission Operator (TOP), or otherwise meet the conditions of notification for deviations from the voltage schedule provided by the TOP. On June 10, 2019, Tilton was online from 5:46 a.m. through 7:25 a.m. During this time, Tilton had issues maintaining its voltage schedule of 142 kV – 144.9 kV. The voltage schedule allows Tilton one hour following unit synchronization before the unit needs to follow the schedule. As a result, Tilton should have met the voltage schedule starting at 6:46 a.m. Tilton's hourly average for the first counting hour was 141.34 kV, which was below the minimum required voltage level per the voltage schedule. Tilton went off-line approximately 10 minutes into the next hour. Tilton called the TOP to notify the TOP of Tilton's trouble maintaining the voltage schedule after Tilton completed the run, which is a delay in notification. This noncompliance started on June 10, 2019 at 6:46 a.m., when Tilton failed to meet its voltage schedule or notified the TOP and ended on June 10, 2019 at 7:25 a.m., when Tilton went off-line. The cause of the noncompliance was that the procedure did not clearly define the individual roles and responsibilities, which created confusion as to the expectations and ownership of specific tasks. Specifically, the GOP monitoring the voltage schedule monitors several different facilities at the same time and the GOP confused the reporting requirement for another facility with Tilton's reporting requirements. The other facilities that the GOP monitors do not have an hourly average.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Tilton's failure to maintain its voltage schedule or to contact the TOP to inform it of excursions from the voltage schedule within a timely manner could have delayed the TOP's ability to respond to deviations in the voltage of the transmission system, potentially resulting in damage to the system or BPS instability. However, the potential impact was minimal, as Tilton was only below the lower level of the schedule by 0.66 kV. In addition, Tilton was only online for 2 hours and 13 minutes, of that, only 1 hour 13 minutes was required to meet the voltage schedule. Tilton is a 92 MW facility with an annual average capacity factor of 5.7% for 2018. No harm is known to have occurred. SERC considered Tilton's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Tilton will complete the following mitigation activities by December 31, 2019: 1) update the GOP procedure. Tilton's previous procedure states the NERC Standard requirements and measures. The updated procedure breaks down the requirements into actionable steps and tells the operators exactly what the operator needs to do to accomplish the requirements; 2) train operators on the updated GOP Procedures including an in-depth review on VAR-002, including the voltage schedule requirement; 3) investigate improved methods to monitor the hourly average; and 4) conduct an internal controls review for VAR-002 to determine if any internal controls can be added to help prevent a reoccurrence.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2019020988	FAC-008-3	R6	Brownsville Public Utilities Board (BPUB)	NCR04018	08/26/2015	08/01/2019	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from December 3, 2018, through January 25, 2019, Texas RE determined that BPUB, as a Distribution Provider (DP), Transmission Owner (TO), and Transmission Operator (TOP), was in noncompliance with FAC-008-3, R6. Specifically, for two transmission lines, the Facility ratings supplied by BPUB were not limited by the most limiting element rating. Additionally, BPUB did not have documentation to support the Equipment Ratings identified for substation conductors at two of its substations. The root cause of this noncompliance was that BPUB did not have a process to ensure accuracy and maintenance of FAC-008-3 R6 documentation, and did not have a process to account for changes to Facilities that would have an impact on Facility Ratings. This noncompliance started on August 26, 2015, the day following the exit briefing of BPUB's previous audit, and ended on August 1, 2019, when BPUB compiled the missing substation documentation, and reviewed and updated all of its Facility Ratings.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Failure to establish accurate Facility Ratings results in the System being operated to incorrect System Operating Limits, and could lead to an unidentified exceedance of the operating capabilities of the Facilities. The risk of this noncompliance was reduced by the fact that BPUB has a relatively small footprint (136 MW of interconnected generation) that does not have an appreciable effect on the BPS. Further, BPUB employs engineers and field personnel with the capability to respond to emergency situations at all times. Texas RE considered the BPUB's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, BPUB: 1) completed an extent of condition review for all Facilities to ensure Facility Ratings were accurate; 2) compiled the missing substation and one line diagrams for Loma Alta and Price Road substations; and 3) revised its Facility Rating procedure to include a process for making changes to applicable Facilities and for saving all documentation in a centralized repository.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018684	VAR-002-4	R1	EDP Renewables North America, LLC (EDPR)	NCR11662	09/06/2016	09/07/2016	Compliance Audit	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted per an existing Multi-Region Registered Entity (MRRE) agreement from September 11, 2017, through September 22, 2017, Texas RE determined that EDPR, as a Generator Operator (GOP), was in noncompliance with VAR-002-4 R1. Specifically, EDPR failed to operate its generator connected to the interconnected transmission system in the automatic voltage control mode. This noncompliance lasted greater than 6 hours and occurred in the Reliability First (RF) Region. EDPR's Headwaters Wind Farm, LLC. (Headwaters) Facility suffered controller issues beginning in August of 2016 and at various times operators coordinated with the Transmission Operator (TOP) to place the AVR in manual mode. A review of the logs indicates that from 18:55 on September 6, 2016, to 01:06 on September 7, 2016, Headwaters was operated with its AVR in manual mode. However, at that particular time, the Facility was not exempted from operating in automatic voltage control mode by the TOP, and no notification was provided to the TOP. This noncompliance lasted 6 hours and eleven minutes. The controller issues at Headwaters were resolved January 3, 2017. The root cause of this noncompliance was a failure by EDPR to follow its applicable Regulatory Compliance Procedure. EDPR has a procedure that provides instructions and this procedure had been implemented and followed on prior occasions. However, due to the on-going nature of the controller issues being experienced at Headwaters, EDPR failed to recognize the need for further coordination with the TOP for each, and every, status change of the AVR. This noncompliance started on September 6, 2016, when EDPR staff placed the AVR at Headwaters in manual mode without notifying its TOP, and ended on September 7, 2016, when EDPR returned that AVR to automatic voltage control mode.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) for the following reasons. This Facility is relatively small with a nameplate rating of 209.3 MW. Due to its small size, this facility would have had only a negligible impact on the system's ability to respond to voltage deviations. Additionally, Texas RE did not identify any unintended voltage controlling actions by the TOP that were related to EDPR's failure to have its AVR in automatic voltage control mode. No harm is known to have occurred. Texas RE considered EDPR's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, EDPR: 1) returned the AVR at the Headwaters Facility to automatic voltage control mode; 2) implemented a procedure requiring the Director of Control Center and HV Operations to review and approve all summary sheets which document that the proper settings have been implemented and that proper documentation and notification has taken place; and 3) implemented a procedure that assigns specific EDPR staff responsibilities for monitoring revisions to the NERC Standards; requires quarterly meetings between key compliance staff; requires periodic monitoring of activities associated with compliance with NERC Standard Implementation Plans and deadlines; and mandates the collection and storage of compliance related evidence. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018687	VAR-002-4	R2	EDP Renewables North America, LLC (EDPR)	NCR11662	07/06/2016	07/10/2017	Compliance Audit	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted per an existing Multi-Region Registered Entity (MRRE) agreement from September 11, 2017, through September 22, 2017, Texas RE determined that EDPR, as a Generator Operator (GOP), was in noncompliance with VAR-002-4 R2. Specifically, EDPR failed to maintain generator voltage and Reactive Power within the assigned schedules. These instances of noncompliance occurred at one Facility in the Western Electricity Coordinating Council (WECC) Region, two Facilities in the Midwest Reliability Organization (MRO) Region, four Facilities in the Reliability First (RF) Region, and one Facility in the Northeast Power Coordinating Council (NPCC) Region. The root cause of this noncompliance was a failure by EDPR to follow its applicable Regulatory Compliance Procedure. EDPR has a procedure that provides instructions and this procedure had been implemented and followed on prior occasions. However, on the occasions identified, EDPR failed to recognize the need for further coordination with the Transmission Operator (TOP) for each, and every, deviation from its generator voltage and Reactive Power schedules. This noncompliance started on July 6, 2016, when the first instance of noncompliance occurred at the Headwaters Facility, continued sporadically occurring at various Facilities, and ended on July 10, 2017, when the last instanced of noncompliance ended also at the Headwaters Facility.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The failure to maintain the TOP's voltage schedule has the potential to affect the reliability of the BPS by causing system voltage to deviate from acceptable levels. However, the average nameplate rating for the wind power plants within EDPR's fleet is 157 MW. Due to their small size, these facilities would have had only a negligible impact on the system's ability to respond to voltage deviations. Additionally, Texas RE did not identify any unintended voltage controlling actions by the TOP that were related to EDPR's failure to follow its generator voltage and Reactive Power schedules. No harm is known to have occurred. Texas RE considered EDPR's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, EDPR: 1) returned voltage and Reactive Power at each of its noncompliant facilities to the assigned schedule; 2) revised its procedure to more specifically identify actions required by EDPR staff; 3) added additional required qualifications for Control Center and HV Operations/ROCC personnel; and 4) implemented a procedure that assigns specific EDPR staff responsibilities for monitoring revisions to the NERC Standards; requires quarterly meetings between key compliance staff; requires periodic monitoring of activities associated with compliance with NERC Standard Implementation Plans and deadlines; and mandates the collection and storage of compliance related evidence. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018019881	PER-005-1	R2	Wind Energy Transmission Texas, LLC (WETT)	NCR11074	08/04/2015	04/16/2018	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from February 26, 2018, through June 12, 2018, Texas RE determined that WETT, as a Transmission Operator (TOP), was in noncompliance with PER-005-1 R2. Specifically, WETT did not have evidence to demonstrate that it had verified, at least once, the capabilities of its System Operators to perform each Bulk Electric System (BES) company-specific reliability-related task performed by its System Operators. WETT stated that all of its System Operators were verified regarding their capability to, in real time, approve or deny system protection outages to ensure system reliability, but WETT was unable to locate or provide evidence that the required verification had occurred. The root cause of the noncompliance was that WETT failed to have an adequate process in place to document that it had verified the capabilities of all System Operators. This noncompliance started on August 4, 2015, the date of the last audit, and ended on April 16, 2018, when WETT verified the capability of its System Operators to perform the BES company-specific reliability-related task at issue.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. WETT did not have evidence to demonstrate that all of its System Operators were trained to identify protective relay failures that reduce system reliability and the actions that would be required if a failure occurred. However, the risk posed by the issue was reduced by the fact that WETT employs NERC certified System Operators located at the primary control center, who are the only WETT employees who have the authority to operate or direct the operation of all of WETT-owned transmission. Further, WETT’s System Operators were trained regarding a similar BES company-specific reliability-related task, regarding approving or denying system equipment outages to ensure system reliability, which WETT indicated contains information that is consistent with the task at issue. Finally, WETT stated that this issue is primarily a documentation retention issue. No harm is known to have occurred. Texas RE considered WETT’s compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, WETT: 1) verified all of its System Operators’ capability to perform the tasks at issue by retraining them on those tasks; and 2) implemented a document management system for storing these records electronically with a dedicated, organized folder structure on its secure document management system. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018019882	PRC-004-5(i)	R1	Wind Energy Transmission Texas, LLC (WETT)	NCR11074	05/16/2017	11/30/2018	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from February 26, 2018 through June 12, 2018, Texas RE determined that WETT, as a Transmission Owner (TO), was in noncompliance with PRC-004-5(i) R1. Specifically, WETT did not, within 120 days of the January 2017 BES interrupting device operations at the Cottonwood and Sand Bluff stations, determine whether its Protection System components caused a Misoperation. For the Sand Bluff incident, WETT sent an email to its adjacent Transmission Operator with the trip record in order to solicit information on whether a Misoperation occurred, and for the Cottonwood incident, WETT stated that an undocumented phone call confirmed that no Misoperation occurred, yet there was no formal documented conclusion that no Misoperation had occurred for either incident until WETT responded to Texas RE information requests as part of this Compliance Audit. The root cause was a lack of a process through which WETT could demonstrate that it analyzed all BES interrupting device operations within 120 days to determine whether its Protection System Components caused a Misoperation. Although WETT states that it took steps after each BES interrupting device operation to determine whether a Misoperation occurred, WETT did not have a sufficient process to ensure that it formally documented its conclusions in order to ensure compliance with PRC-004-5(i). This noncompliance started on May 16, 2017, the first day after the 120-day deadline following a January 15, 2017 BES interrupting device operation at Sand Bluff station, and ended on November 30, 2018, when WETT confirmed that there was not a Misoperation and that all protection devices operated as intended for the January 2017 Sand Bluff incident.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Specifically, although WETT did not timely formally document its investigation to identify whether or not its Protection System components caused a Misoperation, WETT states that it took steps within the 120 day period to determine the cause of the BES interrupting device operations for the Sand Bluff and Cottonwood instances. Additionally, WETT's analysis determined that no Misoperations occurred. No harm is known to have occurred. Texas RE considered the WETT's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, WETT: 1) made the required determinations for the Sand Bluff and Cottonwood incidents; and 2) adopted a procedure whereby WETT has implemented a new tracking mechanism through which WETT analyzes all BES interrupting device operations within 120 days to determine whether its Protection System Components caused a Misoperation. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020146	MOD-027-1	R5	Arizona Public Service Company (AZPS)	NCR05016	6/25/2018	6/28/2018	Self-log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible or confirmed violation.)	On July 31, 2018, AZPS submitted a Self-log stating that, as a Transmission Planner, it was in noncompliance with MOD-027-1 R5. AZPS reported that on June 28, 2018, it discovered that on March 27, 2018 it received reported changes to its turbine/governor and load control verified model information from a Generator Owner (GO), it did not provide a written response within 90 calendar days that the model was usable or not usable, as required by the Standard. On March 27, 2018, a GO sent its MOD-027 verified turbine/governor and load control model information and its MOD-026 modeling information for two generators by email to AZPS. However, the MOD-027 model information email was erroneously sent to an AZPS individual employee’s email account and the MOD-026 model information email was sent to the Transmission Planning department email account. This caused AZPS personnel to mistakenly believe that the MOD-027 related email in the employee email account was a duplicate of the MOD-026 email sent to the department email account and therefore did not forward the email to the department email account. As a result, the MOD-027 email notification was disregarded as a duplicate, resulting in AZPS not providing a written response within 90 calendar days, as required by the Standard. This issue began on June 25, 2018, when AZPS missed the 90 calendar days response deadline and ended on June 28, 2018, when AZPS provided a written response to the GO notifying it that AZPS received its verified turbine/governor and load control model and that it was usable according to MOD-027-1 R5, for a total of 3 days. The root cause of this issue was attributed to gaps in AZPS’s existing processes and gaps in controls for performing the requirements of MOD-027-1 R5.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System. In this instance, AZPS failed to provide a written response to the Generator Owner, within 90 calendar days of receiving turbine/governor and load control verified model information in accordance with Requirement R2, that the model is usable or is not usable, in accordance with MOD-027-1 R5. Failure to incorporate new models could have resulted in an inaccurate representation of the generators in planning models or dynamic simulations. However, as compensation, a previously validated model for the generators was already in place and functioning properly for use in transmission studies. Additionally, the changes that were made were immaterial and did not affect the outcome of other transmission studies.
Mitigation	To mitigate this issue, AZPS has: i. provided a written response to the GO that its model was usable; ii. resent communication to all GOs directing them to send all MOD-026-1 and MOD-027-1 model validation data and reports to the designated department email; iii. established outlook calendar reminders to resend GO communication every six months; iv. instructed Transmission Planning personnel that all communication regarding compliance issues should be sent to and received from the designated department email; v. created a process diagram for MOD-027-1 to ensure recognition of all critical steps; and vi. monthly quality assurance check to ensure that emails in individual inbox and designated department inbox have been logged prior to the monthly sign off on MOD-027-1.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2019021168	MOD-001-1a	R3; R3.5.	Arizona Public Service Company (AZPS)	NCR05016	5/1/2018	12/27/2018	Self-log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On February 1, 2019, AZPS submitted a Self-log stating that, as a Transmission Service Provider, it was in noncompliance with MOD-001-1a R3. AZPS reported that on December 27, 2018, during a compliance related self-assessment, AZPS discovered that it did not update its Available Transfer Capability Implementation Document (ATCID) to reflect the May 1, 2018 commencement commercial operation date of a jointly owned 500kV line, as required by MOD-001-1a R3.5. Once AZPS made the discovery that its ATCID had not been updated as required by the Standard, AZPS updated its ATCID to reflect that the jointly owned 500kV line is in service. This issue began on May 1, 2018, when the jointly owned 500kV line commenced commercial operation and ended on December 27, 2018, when AZPS updated its ATCID to reflect the allocation process for the jointly owned 500kV line, for a total of 241 days. The root cause of this issue was attributed to a lack of formal procedural documentation governing the revision and enhancement of AZPS's ATCID, coupled with staff turnover in the position responsible for revising and updating the ATCID.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System. In this instance, AZPS failed to prepare and keep its Available Transfer Capability Implementation Document (ATCID) current, in accordance with MOD-001-1a R3. Such failure could potentially result in customer's inability to validate the results of the ATC calculations. The inability to validate the ATC might impact a customer's ability to most economically purchase and dispatch power. However, as compensation, AZPS posted a public notice of the commencement of commercial operations for the jointly owned 500kV line on its OASIS home page on April 2, 2018, approximately one month prior to commercial operation. Additionally, the public notice posting provided all potential Transmission Customers with the date of commercial operations, the date that the path would be available for reserving, the date on which scheduling could commence, and all new associated path names among other information. Thus, the information was accessible to Transmission Customers for the entirety of the time between the date of commercial operation of the 500kV line and the update of the ATCID.
Mitigation	To mitigate this issue, AZPS has: i. updated its ATCID to reflect the jointly owned 500kV line; ii. developed procedural documentation to govern future ATCID revisions and updates to provide all current and future team members with written documentation of AZPS's obligations associated with MOD-001-1a R3; iii. communicated the newly developed procedural documentation to applicable personnel to facilitate critical process change management for current team members.; iv. reviewed the current ATCID to correlate its content with the sub-requirements set forth in MOD-001-1a R3 and AZPS's process and methodology for calculating Available Transfer Capability (ATC), to verify that the current ATCID contains all required information and accurately reflects AZPS's methodology for calculating ATC; and v. reviewed the position turnover checklist for the position responsible for AZPS's ATCID to identify whether enhancements are necessary to address the position's responsibilities under AZPS's Internal Compliance Program, to ensure that future team members are apprised of compliance-related responsibilities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019613	EOP-005-2	R11	Arizona Public Service Company (AZPS)	NCR05016	1/1/2018	2/16/2018	Self-log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On April 27, 2018, AZPS submitted a Self-log stating that, as a Distribution Provider (DP), Transmission Owner (TO), and Transmission Operator (TOP), it was in noncompliance with EOP-005-2 R11. AZPS reported that on January 1, 2018, during a compliance related self-assessment, AZPS discovered it did not complete restoration training for 50 of its 250 field switching employees as identified as performing unique tasks associated with AZPS's restoration plan. Specifically, AZPS uses an 18-month interval in its Enterprise Learning Management (ELM) to assign restoration refresher training to field switching personnel, this allows an employee 90 days to complete the training with an additional 90-day recovery period. In this instance, the training links in the ELM system were reset after the original 90-day training window expired resulting in the original due date for the training module being overwritten with a due date that was 90 days in the future. Additionally, the report that AZPS uses to monitor training completion status of all ELM courses for field personnel is generated using data from ELM. Therefore, when the original due date in the ELM was overwritten, the report failed to provide an accurate indicator of the training due date. This issue began on January 1, 2018, when the restoration training was due for 50 personnel and ended on February 16, 2018, when restoration training was completed by the 50 field switching personnel, for a total of 37 days. The root cause of this issue was attributed to AZPS's lack of controls and tools to monitor due dates.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System. In this instance, AZPS failed to provide a minimum of two hours of System restoration training within the two-calendar year due date for 50 of its 250 field switching personnel identified as performing unique tasks associated with the Transmission Operator's restoration plan that are outside of their normal tasks, as required by the Standard. Failure to provide System restoration training to field switching personnel could potentially result in switching personnel being unable to perform, or inadequately performing, the tasks associated with the TOP's restoration plan. However, as compensation, the unique tasks and the associated restoration refresher training course were the same as in 2017 and in 2015. Additionally, all 50 switching personnel subject to this instance successfully completed the restoration training course 2015. Moreover, employees new to an applicable field switching job code in 2016 or 2017 completed the restoration training course as part of their initial training prior to 12/31/2017.
Mitigation	To mitigate this issue, AZPS has: i. provided and completed restoration refresher training to the 50 field switching personnel with outstanding training; ii. developed a 2018 plan to train field switching personnel identified as performing unique tasks associated with AZPS's restoration plan that are outside of their normal tasks including a provision to transition the format from biennial to annual; iii. formalized AZPS's process to train field switching personnel identified as performing unique tasks associated with AZPS's restoration plan that are outside of their normal tasks including: ▪ A delivery schedule with a fixed completion date, whereby the fixed completion date includes a buffer (i.e. recovery) period between the conclusion of the scheduled training and the regulatory non-compliance date; ▪ A method to monitor the status of employees required to complete the training; ▪ Notifications to business unit personnel emphasizing the fixed completion date at pertinent milestones in the process; and ▪ An escalation provision to activate business unit leadership as necessary to ensure employees complete training by the fixed completion date and any make-up training by the required regulatory due date; and ii. implemented AZPS's process to train field switching personnel identified as performing unique tasks associated with AZPS's restoration plan that are outside of their normal tasks in 2018.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020659	BAL-004-WECC-02	R3	Arizona Public Service Company (AZPS)	NCR05016	8/10/2018	9/1/2018	Self-log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On October 31, 2018, AZPS submitted a Self-log stating that, as a Balancing Authority (BA), it was in noncompliance with BAL-004-WECC-02 R3. AZPS reported that on August 13, 2018, it discovered that its Automatic Time Error Correction (ATEC) was not in service; in turn, exceeding the allowable exception period of less than or equal to an accumulated 24 hours per calendar year, as required by the Standard. Specifically, AZPS reported that on August 10, 2018 at 10:57 AM, the Area Control Error (ACE) mode within AZPS's Energy Management System (EMS) switched from "Tie Line Bias + Time" mode, which includes ATEC, to "Tie Line Bias" mode. Although an alarm triggered indicating that the mode had been changed, the System Operator on duty mistakenly believed that the issue was an artifact of the recently issued notice from its Reliability Coordinator that Time Error Correction was indeterminably suspended. The System Operator on duty completed a review of all system indicators and after seeing no adverse system conditions, the alarm was initially discounted as being obsolete. Over the next 3 days, System Operators made multiple attempts to switch back to the "Tie Line Bias + Time" mode, each time the system reverted back to "Tie Line Bias" mode. On August 13, 2018 at 6:30 AM, the issue was reported to AZPS' Information Technology Support and it was determined that the WECC accumulated time error value had exceeded two whole numbers which was halting the calculation when this value was processed by the frequency devices. AZPS'S ATEC was out of service for approximately 75 hours from August 10, 2018 at 10:57 MST until August 13, 2018 at 06:30 MST in Q3 of 2018. This issue began on August 10, 2018, when the 25th hour of its Automatic Time Error Correction (ATEC) was out of service for the calendar quarter and ended on September 1, 2018, when the next calendar quarter started. The root cause of this issue was attributed to AZPS's lack of proper change management for retired Standards.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System. In this instance, AZPS failed to keep its Automatic Time Error Correction (ATEC) in service, with an allowable exception period of less than or equal to an accumulated 24 hours per calendar quarter for ATEC to be out of service. However, as compensation, AZPS reported that operating in the Automatic Time Error Correction (ATEC) ACE mode only serves to payback accumulated Primary Inadvertent Interchange.
Mitigation	To mitigate this issue, AZPS has: iv. reduced the accumulated time error value to less than 100 seconds, allowing the ACE mode to resume operating in ATEC mode; v. reinforced to all BA Operators that the ATEC operating mode remains the nominal condition and must be maintained at all times possible; vi. required all BA Operators to read and acknowledge the Manual Time Error Correction, Activation and Termination/Control Area Time Synchronization procedure; and vii. modified the EMS alarm to clarify the actual condition that has occurred to eliminate confusion with WECC Time Error Correction.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020144	VAR-501-WECC-3.1	R1	Arizona Public Service Company (AZPS)	NCR05016	5/9/2018	6/4/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On July 31, 2018, AZPS submitted a Self-Log stating that, as a Generator Owner, it was in noncompliance with VAR-501-WECC-3.1 R1. AZPS reported that a single Power System Stabilizer (PSS) at one generating unit at a Generating Station was replaced during the generating unit's Fall 2017 refueling outage. The generating unit generation station returned to Commercial Operation on November 11, 2017 with a functioning PSS. Following the installation of the new PSS, AZPS Engineering worked with an external vendor to verify settings and complete start-up testing of the newly installed PSS in accordance with VAR-501-WECC-3.1 R4. This work was concluded on April 9, 2018. On May 15, 2018, while reviewing a monthly VAR report, AZPS identified that it may not have provided an updated Operating Procedure to the Transmission Operator (TOP) for the Generating Station within 180 days as required under VAR-501-WECC-3.1, requirement R1. Since November 9, 2017 was the Commercial Operation date for the generating station, AZPS calculated that it should have provided its Operating Procedure to its TOP by May 9, 2018. This issue began on May 9, 2018 180 days after the Commercial Operation date for the generating station and ended on June 4, 2018 when AZPS provided its updated Operating Procedure to its TOP, for a total of 27 days. The root cause of the issue was attributed to confusion in interpretation of the Standard. AZPS Engineering interpreted the PSS Commercial Operation date in the Standard to mean they had 180 days from the date of completion of R4 (to install and complete start-up testing of a PSS) to complete the action required under R1. Therefore, AZPS believed the due date was October 6, 2018, 180 days following the completion of start-up testing of the PSS on April 9, 2018 to complete this action.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System. In this instance, AZPS failed to provide to its TOP, the GO's written Operating Procedure or other document(s) describing those known circumstances during which the Generator Owner's PSS will not be providing an active signal to the Automatic Voltage Regulator (AVR), within 180 days of the PSS's Commercial Operation date. AZPS identified that if a dynamic disturbance had occurred, the TOP would have had incomplete information related to the PSS installed on this generating station. However, the generating station provided electronic status information for its PSS. In addition, AZPS provided its initial Operating Procedure to the TOP prior to the effective date of the Standard. As well, the generation station utilizes a PSS algorithm executing a digital regulator operating in Automatic Voltage Regulator (AVR) mode, three of four circumstances during which the PSS does not provide an active signal to the AVR remained the same. For the single, remaining circumstance when the PSS turn on level is below the specified limit for the generating unit, the turn on level in per unit and MW is the same for the newly installed PSS and previously installed generating units. The key difference is the previously installed PSS required manual operation to turn on whereas the new unit is automatic. The generation station generating units operate as base loaded units at full load except when starting up or shutting down. Thus, PSS starting level information is immaterial in performing a simulation study. For these reasons, AZPS concluded that the actual and potential risk to the BES was negligible.
Mitigation	To mitigate this issue, AZPS has: i. provided the new PSS operating specifications for the generation station to its TOP; ii. developed and implemented a PSS Commissioning Procedure. This procedure contains a checklist of the steps that must be performed whenever AZPS connects a new generator to the BES or replaces a voltage regulator or PSS on an existing excitation system. It requires PSS operating settings be provided to the applicable Transmission Operator within 180 days of the Commercial Operation Date of the Generator along with any changes to the known circumstances for which the PSS will not be providing an active signal to the AVR. In addition, for PSS installations commissioned by an external vendor, the checklist requires a biweekly calendar reminder to be set to obtain PSS operational settings by the 180-day deadline; and iii. clarified and consolidated its documentation describing those known circumstances during which a PSS would not be providing an active signal to its associated Automatic Voltage Regulator (AVR) and distributed that information to the applicable Transmission Operators for its respective generation unit.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2019021167	VAR-501-WECC-3.1	R2	Arizona Public Service Company (AZPS)	NCR05016	12/08/2018	12/12/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On February 1, 2019, AZPS submitted a Self-log stating that, as a Generator Operator, it was in noncompliance with VAR-501-WECC-3.1 R2. AZPS reported that on December 11, 2018, it discovered it did not have a PSS in service while synchronized during the previous weekend. AZPS performed a generator stator rewind on one generating unit at one generating station, completed in December 2018. AZPS coordinated with its Transmission Operator (TOP) prior to the outage of the Generating Station about the generator stator rewind and associated Design Validation Testing of the excitation system necessary to identify the setting parameters for the Power System Stabilizer (PSS). On December 8, 2018, following a generator stator rewind on the same generating unit, the generating station did not return the PSS to service when the generating unit was synchronized to the Bulk Power System (BPS), due to operational concerns. In this case, AZPS notified its TOP that the PSS on the generating unit was out of service; however, it did not obtain the TOP's agreement. The root cause of the issue was attributed to less than adequate procedure describing the requirements of notifying the TOP that the PSS would be out of service. This issue began on December 8, 2018, when AZPS did not obtain agreement from its TOP that the PSS would be out of service while synchronized and ended on December 12, 2018, when AZPS obtained short-term agreement from its TOP to leave the PSS out of service until the system studies are completed, for a total of 5 days. On December 14, 2018, the TOP completed its system studies and agreed the PSS at the generating unit could be left out of service until mid-January 2019 when the generator vendor could return to complete the excitation system Design Validation Testing necessary to determine the correct settings for the PSS.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, AZPS failed to have its PSS in service while synchronized, except as agreed upon by the Generator Operator, as required by VAR-501-WECC-3.1 R2. As compensation, the effects of one generator out of service on the BPS would not have an impact.
Mitigation	To mitigate this issue, AZPS has: i. obtained a short-term agreement from its TOP to leave the PSS out of service at the generating unit until the system studies were complete; ii. obtained a long-term agreement from the TOP to leave the PSS out of service at the generating unit January 2019 when the vendor would be able to complete PSS testing; iii. completed design validation testing, enabled the PSS for the generating unit and notified the TOP, prior to the end of the agreement between AZPS and the TOP; iv. reviewed all GOP and TOP requirements to clearly identify when the Generating Station Operations personnel need to contact the TOP Power Dispatch Office; v. revised the Main Generator and Excitation Procedure, to more closely align with the Standard, including the requirement to obtain agreement from its TOP to keep a PSS out of service while synchronized; and vi. performed a Training Needs Analysis on the procedure change to Main Generation and Excitation to determine if training is required for the Control Room Operators at the Generating Station.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2019021166	VAR-501-WECC-3.1	R1	Arizona Public Service Company (AZPS)	NCR05016	12/28/2017	10/9/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On February 1, 2019, AZPS submitted a Self-log stating that, as a Generator Owner, it was in noncompliance with VAR-501-WECC-3.1 R1. AZPS reported that in September of 2018, in response to WECC's ongoing Functional Mapping effort, it initiated collaboration efforts to confirm relationships and Transmission Operator (TOP) responsibilities at various generator interconnection locations with neighboring utilities. Following these efforts, on October 9, 2018, AZPS determined that it had incorrectly identified itself as the TOP in the initial VAR-501-WECC-3.1 R1 Implementation Plan for one generation unit which is interconnected into a switchyard that is operated by another TOP. As a result, AZPS, as the Generator Owner (GO) submitted its written PSS Operating Procedures for this generation plant to AZPS's Energy Control Center instead of to the correct TOP. The issue began on December 28, 2017, when the Implementation Plan went into effect, and ended on October 9, 2018 when AZPS, as the GO for this generating unit, provided the respective written PSS Operating Procedures to the correct TOP. The root cause was attributed to a lack of a control document to track and identify the TOP for each of AZPS's generation plants.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, AZPS failed to correctly identify the TOP and did not provide to its TOP, the GO's written Operating Procedure or other document(s) describing those known circumstances during which the Generator Owner's PSS will not be providing an active signal to the Automatic Voltage Regulator (AVR), as required by VAR-501-WECC-3.1 R1. However, as compensation, neither AZPS nor its neighboring entities experienced an actual impact to the BPS due to this violation. The potential impact to the BPS is minimal as the PSS Operating Procedures for the generating plant did not contain any uncommon or unusual information that would require the TOP to modify the operation of their system. Further, there is no impact to any simulation studies because WECC base cases, which are used for all simulation studies in planning and operations horizons, model the generation plant at close to full load with the PSS in service.
Mitigation	To mitigate this issue, AZPS has: i. provided the applicable PSS Operating Procedures to the correct TOP; and ii. developed a control document listing all AZPS owned generation plants with the associated TOPs identified and made this control document available to appropriate personnel.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019431	INT-009-2.1	R1	Bonneville Power Administration (BPA)	NCR05032	1/16/2018	1/16/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On March 23, 2018, BPA submitted a Self-Report stating that, as a Balancing Authority, it was in potential noncompliance with INT-009-2.1 R1. Specifically, on January 16, 2018, BPA experienced technical issues with its scheduling software that resulted in not being able to agree on its Composite Confirmed Interchange with its Adjacent Balancing Authorities (BAs) for three scheduling intervals. The check-outs were not performed at the mutually agreed upon time intervals of 12:10 PM, 12:25 PM, and 12:40 PM on January 16, 2018. The root cause of the issue was attributed to system interactions not considered or identified. Specifically, BPA follows the WECC Interchange Tool (WIT) to check-out, unless the tool is not available. WIT was available during this issue; however, BPA's tag updates were not being sent to WIT because BPA's web Trans Tag Validation process failed to restart after scheduled maintenance by the vendor. Therefore, it was not possible to agree with adjacent Balancing Authorities on the Net Scheduled Interchange value for the three scheduled check-outs. BPA did not use another method to perform check-outs with Adjacent BAs. This issue began on January 16, 2018 at 12:10 PM, when BPA was not able to agree on its Composite Confirmed Interchange with its Adjacent (BAs) for three scheduling intervals and ended on January 16, 2018 at 12:50 PM, when BPA resume scheduled check-outs, for a total of 40 minutes.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, BPA failed to agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent (BAs), for three scheduled check-outs 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 both identical in magnitude to that of the Adjacent (BAs), and opposite in sign or direction to that of the Adjacent (BAs), as required by INT-009-2.1 R1. Failure to agree on the magnitude of Interchange between adjacent BAs could cause the accumulation of inadvertent interchange and incorrect calculation of Net Scheduled Interchange for use in the Area Control Error (ACE) equation. In addition, Interconnection Facilities could become overloaded, however BPA confirmed that any potential overloads would be identified by BPA's RTCA and the operator would be able to curtail any arranged tags. However, as compensation, BPA was in communication with the WIT vendor. In addition, BPA was able to correct the mistakes within the hour, reducing the risk to the BPS. WECC considered BPA's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this issue, BPA has: i. returned to its agreed upon time intervals with its Adjacent BAs with its Composite Confirmed Interchanges. ii. continued to work with its vendor to resolve tag issues within the system. Note: NERC will retire INT-009-2.1 R1 due to its emphasis on transactions and minimal effect to the reliability of the BPS.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020285	INT-009-2.1	R1	Bonneville Power Administration (BPA)	NCR05032	5/17/2018	5/17/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible or confirmed violation.)	On August 28, 2018, BPA submitted a Self-Report stating that, as a Balancing Authority, it was in potential noncompliance with INT-009-2.1 R1. Specifically, on May 17, 2018, BPA experienced technical issues with its scheduling software that resulted in not being able to agree on its Composite Confirmed Interchange with its Adjacent Balancing Authorities (BAs) for three scheduling intervals. The check-outs were not performed at the mutually agreed upon time intervals of 12:10 PM, 12:25 PM, and 12:40 PM on May 17, 2018. During the issue, BPA was able to manually process e-tags, but the e-tags were not being pushed out to the WECC Interchange Tool that is used for check-outs in the region. This issue began on January 16, 2018 at 12:10 PM, when BPA was not able to agree on its Composite Confirmed Interchange with its Adjacent BAs for three scheduling intervals and ended on May 17, 2018 at 1:00 PM, when BPA resume scheduled check-outs for a total of 50 minutes. The root cause of the issue was attributed to means not being provided for assuring adequate equipment quality, reliability or operability. BPA uses the WECC Interchange Tool (WIT) to check-out, unless the tool is not available. WIT was available during this event, but BPA experienced technical difficulties with its scheduling software. The scheduling software system event triggered by a heavy volume of curtailments that occurred during this time, when another entity’s curtailment tool inadvertently curtailed a large volume of tags, multiple times. This heavy volume in the scheduling system caused processing delays. As a result, the Composite Confirmed Interchange values in the WIT did not match between BPA and the Adjustment BAs. BPA has had multiple issues with the software system. This issue began on May 17, 2018 at 12:10 PM, when BPA was not able to agree on its Composite Confirmed Interchange with its Adjacent BAs for three scheduling intervals and ended on May 17, 2018 1:00 PM, when BPA resume scheduled check-outs for a total of 50 minutes.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, BPA failed to agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent BAs, for three scheduled check-outs 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 both identical in magnitude to that of the Adjacent BAs, and opposite in sign or direction to that of the Adjacent BAs, as required by INT-009-2.1 R1. Failure to agree on the magnitude of Interchange between adjacent BAs could cause the accumulation of inadvertent interchange and incorrect calculation of Net Scheduled Interchange for use in the Area Control Error (ACE) equation. In addition, Interconnection Facilities could become overloaded, however any potential overloads would be identified by BPA’s RTCA and the operator would likely be able to curtail any arranged tags. BPA did not have effective preventative or detective controls in place. However, as compensation, BPA calculates Composite Confirmed Interchange with each Adjacent BA utilizing an internally developed software system independent from OATI's Western Interconnection Tool. This internal software incorporates requests for interchange (e-tags) that are not in a final Implemented state when calculating Interchange, thus the entity's scheduler was able to recognize and detect additional e-tags needed to be accounted for in WIT that were not populating for the 3 intervals. In addition, during the instant issue, BPA continued to manage flows on its system as normal to ensure there was no BPS reliability impact until the vendor resolved the issue. If the system experienced an outage, BPA confirmed it would follow WECC instructions per WECC criterion INT-021-WECC-CRT-2.1. WECC considered the BPA's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this issue, BPA has: i. returned to its agreed upon time intervals with its Adjacent BAs with its Composite Confirmed Interchanges; and ii. continued to work with its vendor to resolve tag issues within the system. Note: NERC will retire INT-009-2.1 R1 due to its emphasis on transactions and minimal effect to the reliability of the BPS.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020531	MOD-032-1	R2	CalPeak Power Panoche LLC (CPPA)	NCR05053	07/01/2016	06/03/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On March 1, 2018, CPPA submitted its 2017 Self-Certification stating that it may have a potential noncompliance with MOD-032-1 R2. WECC confirmed the potential noncompliance and advised CPPA to submit a Self-Report for this issue. Subsequently, on October 12, 2018, CPPA submitted a Self-Report stating that it discovered it did not provide its steady-state, dynamics, and short circuit modeling data for its natural gas unit to its Transmission Planner (TP)/Planning Coordinator (PC), according to the data requirements and the 13-calendar month reporting procedure developed by its TP/PC in Requirement R1. The root cause of the issue was attributed to inadequate tracking tools for procedural reporting activities. This issue began July 1, 2016, when the Standard became mandatory and enforceable and ended June 3, 2019, when CPPA provided written notice to its TP and PC that its natural gas unit model had not changed, for a total of 1068 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, CPPA failed to provide its steady-state, dynamics, and short circuit modeling data for its natural gas unit to its TP and PC according to the data requirements and reporting procedures developed by its PC and TP in Requirement R1, as required by MOD-032-1 R2. Failure to provide steady-state, dynamics, and short circuit modeling data could result in the TP/PC having inaccurate data for CPPA's system in its planning and could prevent the TP/PC from adequately conducting analyses of the system, which could result in unexpected voltage deviations, overloads, or unexpected contingencies. However, as compensation, CPPA's models had not changed since the data was submitted originally, therefore, the modeling data in the planning models would have been accurate. Additionally, the unit in scope generates 71 MVA while operating, which would only cause a minor variation in planning results, thus further reducing the risk. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To remediate and mitigate this noncompliance, CPPA: a) submitted steady-state, dynamics, and short circuit modeling data to its TP/PC; b) implemented a new system, DocMinder, to track and monitor NERC Standards applicable to each facility; c) created and implemented reminders in DocMinder to issue reminders 30 days in advance, weekly, and daily until the obligation or task is completed; d) created and implemented escalation notifications in DocMinder to notify management and responsible parties as the deadline approaches; and e) transferred its compliance responsibilities and program to a new owner. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020532	MOD-032-1	R2	CalPeak Power Vaca-Dixon LLC (CPVD)	NCR05054	07/01/2016	06/03/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On March 1, 2018, CPVD submitted its 2017 Self-Certification stating that it may have a potential noncompliance with MOD-032-1 R2. WECC confirmed the potential noncompliance and advised CPVD to submit a Self-Report for this issue. Subsequently, on October 12, 2018, CPVD submitted a Self-Report stating that it discovered it did not provide its steady-state, dynamics, and short circuit modeling data for its natural gas unit to its Transmission Planner (TP)/Planning Coordinator (PC), according to the data requirements and the 13-calendar month reporting procedure developed by its TP/PC in Requirement R1. The root cause of the issue was attributed to inadequate tracking tools for procedural reporting activities. This issue began July 1, 2016, when the Standard became mandatory and enforceable and ended June 3, 2019, when CPVD provided written notice to its TP and PC that its natural gas unit model had not changed, for a total of 1068 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, CPVD failed to provide its steady-state, dynamics, and short circuit modeling data for its natural gas unit to its TP and PC according to the data requirements and reporting procedures developed by its PC and TP in Requirement R1, as required by MOD-032-1 R2. Failure to provide steady-state, dynamics, and short circuit modeling data could result in the TP/PC having inaccurate data for CPVD's system in its planning and could prevent the TP/PC from adequately conducting analyses of the system, which could result in unexpected voltage deviations, overloads, or unexpected contingencies. However, as compensation, CPVD's models had not changed since the data was submitted originally, therefore, the modeling data in the planning models would have been accurate. Additionally, the unit in scope generates 71 MVA while operating, which would only cause a minor variation in planning results, thus further reducing the risk. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To remediate and mitigate this noncompliance, CPVD: a. submitted steady-state, dynamics, and short circuit modeling data to its TP/PC; b. implemented a new system, DocMinder, to track and monitor NERC Standards applicable to each facility; c. created and implemented reminders in DocMinder to issue reminders 30 days in advance, weekly, and daily until the obligation or task is completed; d. created and implemented escalation notifications in DocMinder to notify management and responsible parties as the deadline approaches; and e. transferred its compliance responsibilities and program to a new owner. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017592	BAL-001-2	R2	Idaho Power Company (IPCO)	NCR05191	4/23/2017	4/23/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On May 19, 2017, IPCO submitted a Self-Report stating that, as a Balancing Authority, it was in noncompliance with BAL-001-2 R2. Specifically, on April 23, 2017, IPCO's Balancing Operations exceeded the clock-minute Balancing Authority Area Control Limit (ACE) (BAAL) for 33 consecutive clock-minutes between 8:34 PM to 9:06 PM. From 8:11 PM to 9:10 PM, wind generation Facilities changed from 364 MW to 109 MW, due to inclement weather. During the weather event, 17 wind generation Facilities were generating and experienced a loss of generation during the event, three of which were Bulk Electric System (BES) Facilities. No loss of load occurred. IPCO's detective control identified the ACE excursion and BAAL event through the Energy Management System (EMS) that alerted the operators when the BAAL limit was reached and continued to flash until the issue was resolved. Within two minutes of the BAAL event, IPCO called a neighboring entity that IPCO shares ownership of a coal generation plant with and requested a higher share of its reserves, an overall increase of 160 MW. The neighboring entity responded after 26 minutes, which was longer than usual for similar requests. The full share of the generation, 400 MW, was reached at 9:12 PM, after the end of the BAAL event. At 8:35 PM, IPCO's Generation Dispatcher increased all available IPCO generation from 513 MW to 550 MW at one group of power plants. Another power plant was operating at maximum generation of 400 MW. This issue began on April 23, 2017 at 9:04 PM, when its clock-minute average of Reporting ACE exceeded 30 consecutive clock-minutes and ended on April 23, 2017 at 9:06, when the BAAL event ended for a total of two minutes. The root cause of the issue was attributed to atypical delays in communicating with the neighboring entity that shares ownership of a coal generation plant.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, IPCO failed to operate such that its clock-minute average of Reporting ACE did not exceed its clock-minute BAAL for more than 30 consecutive clock-minutes, calculated in accordance with Attachment 2, for the Western Interconnection by exceeding the BAAL limit for two minutes, as required by BAL-001-2 R2. Failure to remain within BAAL limits could have resulted in frequency excursion beyond defined limits due to over or under generation. However, IPCO had effective detective controls to detect this issue. Specifically, IPCO implemented an alarm that flashes and alerts audibly when there is a BAAL excursion until it is resolved, which detected the BAAL event described above. As compensation, on the day of the BAAL event, IPCO had only 1,723 MW of dispatchable generation online. IPCO has 5,400 MW of generation in its footprint. The peak load on the day of this BAAL event was 1,662 MW for IPCO's area. As additional compensation, the BAAL excursion only lasted 32 minutes, two minutes over the limit of the Standard. No harm is known to have occurred. WECC considered IPCO's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this issue, IPCO has: i. increased generation resources in its area to make up for the loss of variable wind generation; and ii. trained load serving operator personnel on the system desk, generation desk, balancing desk, and interchange desk on reserves and BAAL. The training included group discussion of Reliability Standards associated with Contingency Reserve Obligations, discussion of operating procedures, a review of requirements associated with BAAL, tools for load/weather/wind forecasting, and simulation exercises for restoring Spinning and Contingency reserves. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017616	FAC-009-1	R1	Idaho Power Company (IPCO)	NCR05191	6/18/2007	7/1/2018	Self-Log	Completed

Description of the Noncompliance	On January 30, 2017, IPCO submitted a Self-Log stating, as a Generator Owner, it was in noncompliance with FAC-008-3 R1. However, WECC determined the start date of the noncompliance predates FAC-008-3 R1 and is therefore with FAC-009-1 R1. Specifically, IPCO performed an internal review of its Facility Ratings and Facility Ratings Methodology focusing on the ratings for its Elements related to its generating Facilities. IPCO started with a sample of its generating Facilities and found that the Facility Ratings documented within its Master Data spreadsheet were inconsistent with the Facility Ratings documented within its Power Plant Ratings memo distributed to its operating groups. Further research confirmed that in the actual implementation of the Facility Ratings in the field, IPCO was appropriately operating using the most limiting element in the Facility Rating. However, for 15 generating Facilities there were 18 incorrectly documented Facility Ratings. The root cause was attributed to a lack of internal controls to ensure the Facility Ratings captured within various documents were accurate and complete. This issue began on June 18, 2007, when the Standard became mandatory and enforceable and ended on July 1, 2018, when IPCO updated its various documentation with the correct Facility Ratings, for a total of 4,032 days.
Risk Assessment	WECC determined this violation posed a minimal risk and did not pose a serious and substantial risk to the reliability of the Bulk Power System (BPS). In this instance, IPCO failed to appropriately document and/or maintain the accuracy and completeness of its documented Facility Ratings for 15 of 25 solely owned generating Facilities to ensure consistency with the associated Facility Ratings Methodology. Such failure could lead to design errors, resulting in overloading of a BES element and in the loss of IPCO's Facilities or Protection Systems, as well as neighboring Facilities and Protection Systems not operating as intended, even leading to outages. IPCO did not implement effective preventative or detective controls. However, as compensation, the documented Facility Ratings errors were small compared to the correct Facility Ratings; within 2% of the correct Facility Rating. Though IPCO's documented Facility Ratings incorrectly captured the most limiting element, it was a documentation error, and in the implementation of the Facility Ratings in the field, IPCO was operating using the most limiting element in the Facility Rating. For example, the alarm set in the energy management system (EMS) reflects the correct Facility Ratings. This is also evidenced by the fact that IPCO's generating Facilities have operated for many years without incident of an overload of the generators or supporting equipment. In addition, IPCO generating Facilities were not operated at their maximum capacities due to operation conditions, water availability, and generator efficiencies. WECC determined IPCO's compliance history should not serve as a basis for pursuing an enforcement action and/or applying a penalty due to different facts and circumstances and root cause of the instant issue.
Mitigation	To mitigate this issue, IPCO has: i. developed its master Facilities Ratings documentation to include: a. fields for nameplate ratings information for switches and circuit breakers; b. updated formulas for the Facility Ratings to include the new fields for switches and breakers; c. updated the required nameplate ratings information that specifies the most limiting elements of the switches and breakers; ii. created a new procedure describing the development and maintenance of the of the master Facility Ratings documentation; iii. updated the methodology used to develop the generator Facility Ratings; specifically the rating of the GSU Transformer was clarified to reduce confusion about the information found in the master Facility Ratings documentation; and iv. collected missing data, identified and centrally stored additional supporting data into one location with one naming convention. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017018488	FAC-501-WECC-1	R3	Idaho Power Company (IPCO)	NCR05191	4/23/2017	12/21/2017	Self-Report	Completed

Description of the Noncompliance	On October 16, 2017, IPCO submitted a Self-Report stating that, as a Transmission Owner, it was in noncompliance with FAC-501-WECC-1 R3. Specifically, IPCO discovered that defects on two transmission lines on a Major WECC Transfer Path had been identified, but not repaired within 24 months, as is required by IPCO's Transmission Maintenance and Inspection Plan (TMIP). On one transmission line, the following defects were identified on May 27, 2015: center insulator flashed, due to a bird nest on arm, a top cross arm is broken, and a left pole had woodpecker damage. The defects on the first transmission line were repaired on December 21, 2017. On a second transmission line the following defects were identified on April 23, 2015: a right insulator was broken, and a top cross arm is split. The defects identified on the second transmission line were repaired on September 27, 2017. This issue began on April 23, 2017, when the repairs to the transmission lines were due and ended on December 21, 2017, when all repairs to the defects on all transmission lines were completed for a total of 242 day. The root cause of the issue was attributed to an inefficient process utilized by the IPCO engineering and construction group to track all defects in timely manner.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, IPCO failed to implement and follow its TMIP on five repairs for two transmission lines on a Major WECC Transfer Path. Failure to implement a TMIP for both of these transmission lines could result in a de-rating of the path west-to-east transfer limit from 1,915 MW to 1,840 MW. If both transmission lines had outages, it could result in the loss of load in their micro-systems for the next N-1 Contingency. As compensation, the outage of one of these transmission lines would not affect the other. IPCO schedules the outages of both transmission lines at the same time. In addition, IPCO performs routine patrols twice a year and performs a comprehensive inspection every 10 years. As well, IPCO conducts an emergency inspection every time an outage event is reported, thus reducing the risk to the BPS. WECC considered IPCO's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this issue, IPCO has: i. completed repairs for all defects on all transmission lines; ii. developed a plan to identify process improvements to prevent missing future deadlines for defects, including a new maintenance process; iii. created a new monthly meeting to review all open items; iv. created a new report to review open items during the monthly meeting for all defects coming due for completion; v. created a tracking process for all incomplete repairs in its Transmission line reports and Maintenance Tracking System (TRAM). The progress of work for correcting defects in worksheets or corrective action plans are tracked in SharePoint; and vi. updated IPCO's TMIP with the new process changes.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020426	EOP-008-1	R1, R1.3	Idaho Power Company (IPCO)	NCR05191	7/1/2013	11/30/2018	Compliance Audit	Completed

Description of the Noncompliance	During a Compliance Audit conducted from September 4, 2018 through September 14, 2018, WECC determined that IPCO, as a Balancing Authority and Transmission Operator, was in noncompliance with EOP-008-1 R1. Specifically, IPCO had an Operator Backup Checklist that did not demonstrate that the backup control center (BCC) functionality was consistent with the primary control center (PCC), as is required for an Operating Plan. For its Operator Backup Checklist, IPCO checks the backup functionality at least quarterly. During the check, the operator transfers control to the backup control center, tests the communications from the backup control center and demonstrates the ability to communicate with neighboring entities. The Operator Backup Checklist is used to verify that monitoring, control, alarming, and logging functions are accessible and functional by the System Operators. Though the Operator Backup Checklist is not a part of IPCO's Operating Plan nor referenced in its Operating Plan, its purpose is to ensure that the backup functionality is operating correctly. However, the Operator Backup Checklist nor the Operating Plan did not include measures to ensure that the BCC functionality is consistent with the PCC, such as checking that software or network versions are consistent. This issue began on July 1, 2013, when IPCO did not have an Operating Plan consistent with the requirements of the Standard and ended on November 30, 2018, when IPCO updated its Operating Plan to include a process for keeping the backup functionality consistent with the PCC for a total of 1979 days. The root cause of the issue was attributed to a misinterpretation of the requirements of the Standard, IPCO incorrectly thought the Operator Backup Checklist met the requirements of the Standard.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, IPCO failed to have an Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BPS in the event that its PCC functionality is lost. Specifically, the Operating Plan for backup functionality failed to include the following, at a minimum: An Operating Process for keeping the backup functionality consistent with the primary control center, as required by EOP-008-1 R1. IPCO has 2,474 MW of BES generation in its Balancing Authority area with a BA peak load of 3,774 MW. A failure to have an Operating Plan that includes a consistent BCC and PCC could cause IPCO not to be able to operate its BCC if the PCC functionality is lost. IPCO did not have any preventative or detective controls to prevent or detect this issue. However, as compensation, the Operator Backup Checklist checks the backup functionality at least quarterly. During the check, the operator transfers control to the backup control center, tests the communications from the backup control center and demonstrates the ability to communicate with neighboring entities. The Operator Backup Checklist is used to verify that monitoring, control, alarming, and logging functions are accessible and functional by the System Operators, thus, reducing potential harm. WECC considered IPCO's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this issue, IPCO has: i. updated its Operating Plan to describe how the BCC is maintained to keep functionality with PCC; and ii. updated the Loss of Control Center Functionality document to include relevant BCC and PCC requirements and updated to reference the checklist used for performing functional tests that operators use to ensure that backup functionality is consistent with the primary control center in order to align IPCO personnel with the requirements of the Standard. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020427	FAC-009-1	R1	Idaho Power Company (IPCO)	NCR05191	6/18/2007	9/12/2018	Compliance Audit	Completed

Description of the Noncompliance	During a Compliance Audit conducted September 4, 2018 through September 14, 2018, WECC determined IPCO, as a Transmission Owner, had a potential noncompliance with FAC-009-1 R1. Specifically, on one 138 kV line, the jumper was the most limiting element, for winter normal ratings, but it had not been correctly rated and was therefore inconsistent with IPCO's Facility Ratings Methodology. IPCO had two drawings for the switch yard to provide different elevation views, one north-facing and the other west-facing. The jumper was not identified on the west-facing drawing. Typically, the single breaker does not have two views; however, for double breakers two views would be typical. Since the single breaker does not typically have two views, the IPCO engineer did not check for additional drawings which led to the incorrectly documented Facility Rating. The root cause of was attributed an omission of steps by the IPCO engineer based on the assumption that single breakers typically do not have two views in the drawings and therefore missed including the jumper in the Facility Rating spreadsheet. This issue began on June 18, 2007, when the Standard became mandatory and enforceable and ended on September 12, 2018, when the jumper was appropriately rated and added to the Facility Ratings spreadsheet for a total of 4,105 days.
Risk Assessment	WECC determined this violation posed a minimal risk and did not pose a serious and substantial risk to the reliability of the BPS. In this instance, IPCO failed to establish the Facility Rating for one 138 kV line to include a jumper, which was the most limiting element for the Winter Normal season ratings. Such failure could have resulted in the equipment being operated above appropriate ratings and incorrect System Operating Limits could result in overloads, unexpected outages, or operations in unstudied conditions on the 138-kV line. However, as compensation, the 138 kV line associated with this issue is not part of a Major WECC Transfer Path. In the winter, this line serves as a backup line because the line's purpose is for serving summer irrigation load. The jumper impacts only the Winter Normal season ratings. The jumper is the most limiting element for the winter normal rating and changes the rating from 1770 A to 1642 A, thus the 138 kV line was overestimated by 7.2% for its normal winter rating, thus decreasing the risk because IPCO's peak load occurs during the summer. WECC determined IPCO's compliance history should not serve as a basis for pursuing an enforcement action and/or applying a penalty due to different facts and circumstances and root cause of the instant issue.
Mitigation	To mitigate this issue, IPCO has: i. updated the 138 kV Facility Rating spreadsheet to include the jumper rating; ii. completed compliance training on Facility Ratings and FAC-008 including participants from system planning, station engineers, station designers, and GIS. The training included information about the instant violation to emphasize the importance of data source availability, consistency, accuracy, and the importance of considering all data sources in establishing Facility Ratings, and emphasized that the ratings must be consistent with the methodology; and iii. sent a follow-up email to applicable staff detailing the lessons learned and recommendations for improvement. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2019021300	COM-001-2.1	R11	Kern River Cogeneration Company (KRCC)	NCR05204	2/13/2017	3/30/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On April 3, 2019, KRCC submitted a Self-Report stating, as a Generator Operator, it was in potential noncompliance with COM-001-2.1 R11. On January 23, 2019, during a third-party NERC program analysis, KRCC discovered that on four occasions it did not notify its Balancing Authority (BA) or Transmission Operator (TOP) when its control room phone system was lost due to the failure of the uninterruptable power supply however, KRCC did notify its Scheduling Coordinator of the communication loss. The first instance began on February 13, 2017 at 12:07 AM when the control room desk phone lost power and ended on February 13, 2017 at 4:00 AM when power was restored to the control room desk phone, for a total of 3 hours and 53 minutes. The second instance began on November 22, 2017 at 4:25 PM when the control room desk phone lost power and ended on November 22, 2017 at 5:19 PM when power was restored to the control room desk phone, for a total of 54 minutes. The third instance began on February 1, 2018 at 5:04 AM when the control room desk phone lost power and ended on February 1, 2018 at 7:00 AM when power was restored to the control room desk phone, for a total of 1 hour and 56 minutes. The fourth instance began March 30, 2018 at 1:10 PM when the control room desk phone lost power and ended on March 30, 2018 at 5:50 PM when power was restored to the control room desk phone, for a total of 3 hours and 40 minutes. The root cause of the issues was attributed to KRCC's COM-001 procedure and training document did not identify the control room phone as the Interpersonal Communication device and did not include clearly defined steps for communication upon the loss of the desk phone. As a result, KRCC's Operations personnel were not aware of the requirements to notify its BA and TOP. After reviewing all relevant information, WECC Enforcement determined that KRCC failed to effectively perform COM-001-2.1 R11.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, on four separate occasions, KRCC failed to consult its BA and TOP affected by the failure of its Interpersonal Communication capability to determine a mutually agreeable action for the restoration of its Interpersonal Communication capability. Failure to consult with entities affected by the loss of Interpersonal Communications capability could result in the affected entities being unaware of the loss of communications and being unable to effectively communicate Operating Instructions or other measures necessary to maintain reliability. As compensation, KRCC did notify the scheduling coordinator when the control room phone lost power ensuring that the coordinator would not issue any Operating Instructions during these periods. Also, a search of the market notice records confirmed that no Ancillary Services scarcity events coincided with the dates of loss of Interpersonal Communication. Additionally, KRCC contributes a total of 300 MW of generation to the grid, further reducing the risk. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, KRCC has: 1) updated COM-001 procedure and training materials to identify the control room desk phone as the single interpersonal communication capability device and include defined steps for communication upon loss of interpersonal communication capability; 2) implemented the use of a loss of Interpersonal Communication form to streamline the process of notifying affected entities of phone loss and to log details appropriately. 3) provided COM specific training to all Operations Personnel; and 4) confirmed all Operations Personnel reviewed and acknowledged training materials. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020534	MOD-032-1	R2	Midway Peaking, LLC (MIDP)	NCR10323	07/01/2016	06/03/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On March 1, 2018, MIDP submitted its 2017 Self-Certification stating that it may have a potential noncompliance with MOD-032-1 R2. WECC confirmed the potential noncompliance and advised MIDP to submit a Self-Report for this issue. Subsequently, on October 12, 2018, MIDP submitted a Self-Report stating that it discovered it did not provide its steady-state, dynamics, and short circuit modeling data for its natural gas unit to its Transmission Planner (TP)/Planning Coordinator (PC), according to the data requirements and the 13-calendar month reporting procedure developed by its TP/PC in Requirement R1. The root cause of the issue was attributed to inadequate tracking tools for procedural reporting activities. This issue began July 1, 2016, when the Standard became mandatory and enforceable and ended June 3, 2019, when MIDP provided written notice to its TP and PC that its natural gas unit model had not changed, for a total of 1068 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, MIDP failed to provide its steady-state, dynamics, and short circuit modeling data for its natural gas unit to its TP and PC according to the data requirements and reporting procedures developed by its PC and TP in Requirement R1, as required by MOD-032-1 R2. Failure to provide steady-state, dynamics, and short circuit modeling data could result in the TP/PC having inaccurate data for MIDP's system in its planning and could prevent the TP/PC from adequately conducting analyses of the system, which could result in unexpected voltage deviations, overloads, or unexpected contingencies. However, as compensation, MIDP's models had not changed since the data was submitted originally, therefore, the modeling data in the planning models would have been accurate. Additionally, the unit in scope generates 164 MVA while operating, which would only cause a minor variation in planning results, thus further reducing the risk. WECC considered MIDP's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To remediate and mitigate this noncompliance, MIDP: a. submitted steady-state, dynamics, and short circuit modeling data to its TP/PC; b. implemented a new system, DocMinder, to track and monitor NERC Standards applicable to each facility; c. created and implemented reminders in DocMinder to issue reminders 30 days in advance, weekly, and daily until the obligation or task is completed; d. created and implemented escalation notifications in DocMinder to notify management and responsible parties as the deadline approaches; and e. transferred its compliance responsibilities and program to a new owner. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020533	MOD-032-1	R2	Malaga Power, LLC (MLGP)	NCR11542	07/01/2016	06/03/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On March 1, 2018, MLGP submitted its 2017 Self-Certification stating that it may have a potential noncompliance with MOD-032-1 R2. WECC confirmed the potential noncompliance and advised MLGP to submit a Self-Report for this issue. Subsequently, on October 12, 2018, MLGP submitted a Self-Report stating that it discovered it did not provide its steady-state, dynamics, and short circuit modeling data for its natural gas unit to its Transmission Planner (TP)/Planning Coordinator (PC), according to the data requirements and the 13-calendar month reporting procedure developed by its TP/PC in Requirement R1. The root cause of the issue was attributed to inadequate tracking tools for procedural reporting activities. This issue began July 1, 2016, when the Standard became mandatory and enforceable and ended June 3, 2019, when MLGP provided written notice to its TP and PC that its natural gas unit model had not changed, for a total of 1068 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, MLGP failed to provide its steady-state, dynamics, and short circuit modeling data for its natural gas unit to its TP and PC according to the data requirements and reporting procedures developed by its PC and TP in Requirement R1, as required by MOD-032-1 R2. Failure to provide steady-state, dynamics, and short circuit modeling data could result in the TP/PC having inaccurate data for MLGP's system in its planning and could prevent the TP/PC from adequately conducting analyses of the system, which could result in unexpected voltage deviations, overloads, or unexpected contingencies. However, as compensation, MLGP's models had not changed since the data was submitted originally, therefore, the modeling data in the planning models would have been accurate. Additionally, the unit in scope generates 142 MVA while operating, which would only cause a minor variation in planning results, thus further reducing the risk. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To remediate and mitigate this noncompliance, MLGP: a. submitted steady-state, dynamics, and short circuit modeling data to its TP/PC; b. implemented a new system, DocMinder, to track and monitor NERC Standards applicable to each facility; c. created and implemented reminders in DocMinder to issue reminders 30 days in advance, weekly, and daily until the obligation or task is completed; d. created and implemented escalation notifications in DocMinder to notify management and responsible parties as the deadline approaches; and e. transferred its compliance responsibilities and program to a new owner. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019113	BAL-001-2	R2	NorthWestern Corporation (NWC)	NCR05282	11/18/2017	11/18/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On February 1, 2018, NWC submitted a Self-Report stating that, as a Balancing Authority, it was in noncompliance with BAL-001-2 R2. Specifically, at 4:20 PM on November 18, 2017, there was a sharp decline in wind generation in the Balancing Authority area which caused the Balancing Authority ACE Limit (BAAL) to be negative. Following its Operating Protocol, the NWC Dispatch Operator requested INC Capacity from the NWC Energy Supply to offset the loss of wind generation. NWC Energy Supply then requested capacity from three generating units and these units all increased their output. However, one of the generating units tripped offline because of a faulty thermocouple. One minute later, the NWC Energy Supply scheduler deployed spinning contingency reserves from another generating unit, alleviating the BAAL event at 4:51 PM. This issue began on November 18, 2017 at 4:51, when its clock-minute average of Reporting ACE exceeded 30 consecutive clock-minutes and ended on November 18, 2017 at 4:52 when the BAAL event ended, for a total of two minutes. The root cause of the issue was attributed to a damaged thermocouple.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System. In this instance, NWC failed to operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute BAAL for more than 30 consecutive clock-minutes, calculated in accordance with Attachment 2, for the Western Interconnection, for two minutes. Such failure could result in continuing degradation of the BAAL and frequency for NWC's 800 MVA of generation or its neighboring entities. However, NWC implemented good detective controls. Specifically, NWC has an audible alarm that is initiated when the BAAL exceeds trigger limits to prompt the System Operator to respond at the Primary Control Center. In addition, there is a backup display available when the primary BAAL display is not functioning correctly. As compensation, the event only lasted 32 minutes, two minutes past the requirements of the Standard. No harm is known to have occurred. WECC considered NWC's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this issue, NWC has: i. deployed spinning contingencies reserves to alleviate the BAAL event; ii. replaced thermocouple in generating unit referenced above; and iii. refined Operating Protocols with the System Operators including timelines to specify that when the amount of BAAL exceedance is large (i.e. greater than 60 MW) the deployment of additional capacity should be initiated within 10 to 12 minutes of the event. When the amount of the BAAL exceedance is greater than the available capacity, corrective action should begin as soon as the operators determine it is necessary. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019479	MOD-027-1	R4	Pacific Gas and Electric Company (PGAE)	NCR05299	08/21/2017	12/19/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On March 30, 2018, PGAE submitted a Self-Report stating, as a Generator Owner (GO), it was in potential noncompliance with MOD-027-1 R4. On August 21, 2017, PGAE discovered that on February 20, 2017, when it upgraded a governor on a hydro generating unit with a digital controller, which altered the governor response characteristics, it did not provide revised model data or plans to perform model verification (in accordance with Requirement R2) to its Transmission Planner (TP) for the hydro generating unit, within 180 calendar days of making changes to the turbine/governor and load control that alter the equipment response characteristic, as required by MOD-027-1 R4. The root cause of this noncompliance was attributed to PGAE's lack of defined roles and responsibilities pertaining to MOD-027 requirements. This noncompliance began August 21, 2017, when PGAE missed the 180 calendar days response deadline and ended on December 19, 2017, when PGAE submitted its plans to perform model verification to its TP, for a total of 121 days. After reviewing all relevant information, WECC Enforcement determined PGAE failed to properly perform MOD-027-1 R4.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, PGAE failed to provide revised model data or plans to perform model verification (in accordance with Requirement R2) for its hydro generating unit to its Transmission Planner within 180 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic. Failure to have current modeling data or a plan developed after modifications of the governor could have resulted in model parameters being used in dynamic simulations to assess BES reliability, which does not accurately represent generator unit real power response to system frequency variations. However, as compensation, the generating unit subject to this instance is an 80.63 MVA hydro unit, thereby reducing the risk. WECC considered the PGAE's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, PGAE has: 1) informed its TP of changes to the hydro unit's governor and updated them with new models; 2) completed an extent of condition to confirm that all other facilities that performed work that altered governor response characteristics were timely submitted to its TP from 2014 to the present; 3) held tailboard meeting defining roles and responsibilities for all generation personnel responsible for complying with MOD-027-1 R4; and 4) modified the current governor purchase specification to require the manufacture to provide the required test/commissioning data or complete model validation per MOD-027-1. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019834	MOD-026-1	R6.; R6.1.; R6.2.; R6.3.	Pacific Gas and Electric Company (PGAE)	NCR05299	04/25/2017	09/12/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On June 8, 2018, PGAE submitted a Self-Report stating, as a Transmission Planner (TP), it was in potential noncompliance with MOD-026-1 R6. On September 12, 2017, PGAE discovered that on January 24, 2017, when it received reported changes to its plant volt/var control function model information from a Generator Owner (GO), it did not provide a written response within 90 calendar days that the model was usable, for a 100 MW solar plant. PGAE personnel viewed the email upon receipt but did not mark that the email required follow-up. As a result, the email notification remained in the mailbox, resulting in PGAE not providing a written response within 90 calendar days as required by the Standard Requirements. The root cause of this noncompliance was attributed to PGAE's insufficient status tracking of tasks for MOD-026-1. This noncompliance began April 25, 2017, when PGAE missed the 90 calendar days response deadline and ended on September 12, 2017, when PGAE provided a written response to the GO notifying it that PGAE received its plant volt/var control function model information and that it was usable according to MOD-026-1 R6, for a total of 141 days. After reviewing all relevant information, WECC Enforcement determined PGAE failed to properly perform MOD-026-1 R6.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, PGAE failed to provide a written response to the Generator Owner, within 90 calendar days of receiving a plant volt/var control function model information in accordance with Requirement R2 that the model is usable or is not usable for a 100 MW solar plant, in accordance with MOD-026-1. Failure to incorporate new models could have resulted in an inaccurate representation of the solar plant in planning models or dynamic simulations. However, as compensation, the GO affected by these instances is a solar farm that contributes 100 MW to the grid while operating, and is not utilized as a firm resource, thereby reducing the risk. WECC considered the PGAE's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, PGAE has: 1) provided a written response to the GO that its model was usable; and 2) created and implemented new procedures to ensure that all requests related to model verification are tracked and responded to on time. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019835	MOD-027-1	R5.; R5.1.; R5.2.; R5.3.	Pacific Gas and Electric Company (PGAE)	NCR05299	04/25/2017	09/12/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On June 8, 2018, PGAE submitted a Self-Report stating, as a Transmission Planner (TP), it was in potential noncompliance with MOD-027-1 R5. On September 12, 2017, PGAE discovered that on January 24, 2017, when it received reported changes to its verified active power/frequency control system model information from a Generator Owner (GO), it did not provide a written response within 90 calendar days that the model was usable, for a 100 MW solar plant. PGAE personnel viewed the email upon receipt but did not mark that the email required follow-up. As a result, the email notification remained in the mailbox, resulting in PGAE not providing a written response within 90 calendar days as required by the Standard Requirements. The root cause of this noncompliance was attributed to PGAE's insufficient status tracking of tasks for MOD-027-1. This noncompliance began April 25, 2017, when PGAE missed the 90 calendar days response deadline and ended on September 12, 2017, when PGAE provided a written response to the GO notifying it that PGAE received its verified active power/frequency control system model and that it was usable according to MOD-027-1 R5, for a total of 141 days. After reviewing all relevant information, WECC Enforcement determined PGAE failed to properly perform MOD-027-1 R5.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, PGAE failed to provide a written response to the Generator Owner, within 90 calendar days of receiving verified active power/frequency control system model information in accordance with Requirement R2, that the model is usable or is not usable for a 100 MW solar plant, in accordance with MOD-027-1. Failure to incorporate new models could have resulted in an inaccurate representation of the solar plant in planning models or dynamic simulations. However, as compensation, the GO affected by these instances is a solar farm that contributes 100 MW to the grid while operating, and is not utilized as a firm resource, thereby reducing the risk. WECC considered the PGAE's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, PGAE has: 1) provided a written response to the GO that its model was usable; and 2) created and implemented new procedures to ensure that all requests related to model verification are tracked and responded to on time. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017016942	FAC-501-WECC-1	R3	Public Service Company of New Mexico (PNM)	NCR05333	7/1/2011	4/24/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On February 7, 2017, PNM submitted a Self-Report stating, as a Transmission Owner, it had a potential noncompliance with FAC-501-WECC-1 R3. The Self-Reported was validated during a WECC Compliance Audit conducted May 8, 2017 to May 19, 2017. Specifically, PNM did not complete moisture and timing test maintenance activities for six of its breakers on a four-year interval, as required by its Transmission Maintenance and Inspection Plan (TMIP). Of the six breakers, one is on a Major WECC Transfer Path. During routine operations, PNM discovered it did not apply triggers within its software work management system for four of the breakers and did not enter the required maintenance and testing tasks for the other two breakers into the same system, before the Standard became mandatory and enforceable, on July 1, 2011. PNM completed 208 applicable maintenance intervals on time, however the six breakers' maintenance records mentioned above indicated partial completion. The root cause was attributed to the lack of internal controls to validate that testing and maintenance deadlines were appropriately entered into the software work management system. Therefore, the necessary notifications did not alert the appropriate staff of the required testing deadlines. WECC determined that this issue began on July 1, 2011, when the Standard became mandatory and enforceable, and ended on April 24, 2017, when PNM completed the moisture and timing test maintenance activities for the six breakers, for a total of 2,125 days.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, PNM failed to implement and follow its TMIP, as required by FAC-501-WECC-1 R3 for six breakers. Failure to maintain the elements of a Major WECC Transfer Path in accordance with a TMIP could result in degraded equipment that is not able to respond to normal or transient system conditions. Potential unknown operating limits could result in equipment isolating transmission elements or failing to operate. Loss of the transmission elements may result in parallel transmission lines exceeding operating limits, direct loss of load, loss of generation, or delayed system restoration. PNM did not implement effective preventative and detective controls. However, as compensation, the substation associated with this issue uses a breaker and a half scheme, which allows the breakers to be easily isolated and reducing the risk that one breaker, during normal operation, could cause harm to the BPS. Additionally, PNM had completed partial maintenance tasks required by its TMIP but could not locate records demonstrating the moisture and timing tests for the six breakers associated with the instant issue, reducing the risk. Furthermore, PNM maintained and tested 208 devices, reducing the likelihood of harm to the BPS.
Mitigation	To mitigate this noncompliance, PNM: 1) completed moisture and timing test maintenance activities for the six breakers associated with this issue; 2) documented a new formal procedure to ensure the collection, evidence review, packaging and storage of evidence for maintenance activities, as required by the Standard; 3) reconciled the list of devices and the notifications in the software work management system to ensure consistency; and 4) implemented annual reconciliation to ensure the list of devices is consistent with the notifications in the software work management system WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019373	PRC-001-1.1(ii)	R3	Public Service Company of New Mexico (PNM)	NCR05333	3/15/2017	8/24/2017	Self-Report	Completed

Description of the Noncompliance	On March 12, 2018, PNM submitted a Self-Report stating, as a Transmission Operator it had a potential noncompliance with PRC-001-1.1(ii) R3. Specifically, PNM replaced a line relay on one 115 kV line on March 15, 2017. However, PNM did not communicate this new protective system line relay setting with its neighboring TOP until August 24, 2017. The root cause of the issue was attributed to a lack of internal controls to ensure a formal check for proper coordination of new protective system devices. WECC determined that this issue began on March 16, 2017, when PNM replaced line relays and needed to coordinate with its neighboring TOP and ended on August 24, 2017, when PNM coordinated protective devices and changes with its neighboring TOP, for a total of 163 days.
Risk Assessment	WECC determined that this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the BPS. In this instance, PNM failed to coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities for one new relay, as required by PRC-001.1(ii) R3. PNM implemented good detective controls including the annual review for Self-Certification, which detected this issue. In addition, as compensation, although a miscommunication of the 115kV transmission line relays associated with this issue could have resulted in an unnecessary trip of the 115kV line, a trip would not lead to loss of load, impact to a Remedial Action Scheme or Interconnection Reliability Operating Limit, and would not cause BPS instability, separation, or cascading failures.
Mitigation	To mitigate this noncompliance, PNM: 1) sent an email to the neighboring TOP to communicate the setting changes; 2) updated its Power Base application to add check boxes as an internal control for relay settings development and review; 3) developed a template for PNM's Protection System Engineers to communicate and coordinate any Protection System changes; 4) trained PNM's Protection System Engineers responsible for relay settings and coordination on the update made in the Relay Philosophy and the new template that the Protection System Engineers will use to adhere to the requirements of the Standard.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019374	EOP-005-2	R4	Public Service Company of New Mexico (PNM)	NCR05333	1/12/2018	3/16/2018	Self-Report	Completed

Description of the Noncompliance	On March 12, 2018, PNM submitted a Self-Report stating that, as a Transmission Operator (TOP), it was in noncompliance with EOP-005-2 R4. PNM discovered that it had not updated its restoration plan prior to implementing a planned Bulk Electric System (BES) modification. Specifically, on January 12, 2018 a new 115 kV switching station was added, which changed a leg of the cranking path identified in the restoration plan, but PNM did not update its restoration plan's primary cranking path. This cranking path is one of three cranking paths that PNM considers primary cranking paths for restoration based on their importance, timeliness, simplicity, and regional flexibility. This cranking path would provide start-up power to a 42 MW gas powered unit. After the planned BES modification, two additional breakers would need to be closed to use the cranking path for restoration, thus requiring a change in the implementation of PNM's restoration plan. The root cause of the issue was attributed to PNM not identifying pending system changes that would impact cranking paths. WECC determined this issue began on January 12, 2018, when PNM did not update its restoration plan and ended on March 16, 2018, when PNM updated its restoration plan to include the new primary cranking path for a total of 64 days.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the BPS. In this instance, PNM failed to update its restoration plan within 90 calendar days after identifying any unplanned permanent System modifications, or prior to implementing a planned BES modification, that would change the implementation of its restoration plan, as required by EOP-005-2 R4. However, as compensation, if the operator were not able to use the cranking path subject to this issue, the operator would have two other cranking paths to use. WECC determined that PNM's relevant prior compliance history with EOP-005-2 R4 includes NERC Violation ID: WECC2016015563. WECC determined PNM's compliance history should not serve as a basis for pursuing an enforcement action and/or applying a penalty because the previous violation of EOP-005-2 R4 was also filed as a CE and does not reflect a systemic issue.
Mitigation	To mitigate this noncompliance, PNM: 1) updated its Restoration Plan submitted the updated Restoration Plan to the Reliability Coordinator; and 2) amended monthly meeting between Transmission Planning and Operations Department to require validation for the proposed new facilities be studied with the in-force Restoration Plan during the meeting to demonstrate that the impact conclusion is correct.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2016016656	PRC-023-2	R1	Seattle City Light (SCL)	NCR05382	3/28/2014	11/16/2016	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On December 9, 2016, the entity submitted a Self-Report stating, as a Transmission Owner it was in potential noncompliance with PRC-023-2 R1. Specifically, on November 8, 2016, during its annual review, the entity discovered that its relay technician had improperly set its loadability limits for one phase protective relay on one 230 kV transmission line beginning on March 28, 2014. The phase protective transmission line relay was set at 83.3 Ohms (primary)/10 Ohms (secondary), but it should have been set at 50 Ohms (primary)/6 Ohms (secondary). The correct Facility Rating for the 230 kV transmission line at the Max Torque Angle (MTA), with the 150% load multiplier, and a depressed voltage of 85%, is 63.97 Ohms. The phase protective transmission line relay reach was set at a value greater than the value of the transmission line's emergency load capability, thus the relay was out of tolerance, per PRC-023-2 R1, Criterion 1. The root cause of the issue was attributed to inadequate internal controls to verify that the secondary relay settings had been input correctly by the relay technician. This issue began on March 28, 2014, when the entity set a phase protective transmission line relay out of tolerance, and ended on November 16, 2016, when the entity adjusted the transmission line relay set from 83.3 Ohms (primary)/10 Ohms (secondary) to 50 Ohms (primary)/6 Ohms (secondary), for a total of 965 days. After reviewing all relevant information, WECC determined the entity failed to use Criterion 1 to set one phase protective transmission line relay so that it does not operate at or below 150% of the highest seasonal Facility Rating of a circuit as required by Criterion 1 of PRC-023-2 R1.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the BPS. In this instance, the entity failed to adhere to Criterion 1 to set one phase protective transmission line relay on one 230 kV transmission line so that it did not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes), for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. The entity failed to evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees, as required by Criterion 1 of PRC-023-2 R1. This failure could have resulted in premature line tripping, causing the load to be distributed to other transmission lines that could be near their respective SOLs. However, as compensation, the entity had only one phase protective transmission line relay that was set out of tolerance. In addition, the entity performed transmission planning assessments annually that included single and multiple contingencies which monitor for any loading greater than 95% of its emergency rating. The line subject to this violation was not shown to result in loading greater than 95% in the transmission planning assessments, indicating it would be very unlikely for the flow of this line to reach the threshold of the relay, thus lessening the risk to the BPS.
Mitigation	To mitigate this noncompliance, the entity: 1) corrected the phase protective relay from limiting transmission system loadability, as reflected by the requirements of Criterion 1, specifically it changed relay settings from 83.3 Ohms (primary)/10 Ohms (secondary) to 50 Ohms (primary)/6 Ohms (secondary) confirmed for field installations; and 2) implemented a new procedure to require relay technicians to check "As Found" for relay settings prior to starting work to ensure there are not any discrepancies. When the work is completed, relay technicians are required to verify the "As Left" for relay settings against the database to ensure there are not any discrepancies. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020214	TOP - 001-3	R1	Seattle City Light (SCL)	NCR05382	11/13/2017	11/13/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On March 1, 2018 the entity Self-Certified noncompliant as a Transmission Operator (TOP) with TOP-001-3 R1. After the entity completed a compliance review of this noncompliance and reviewed compliance with other Standards as a result of this instance, it submitted a Self-Report on August 10, 2018. On the morning of November 13, 2017, a storm caused the loss of one of the entity's 240 kV transmission lines resulting in an outage. This outage did not result in any pre- or post-Contingency System Operating Limit (SOL) exceedances. At 4:58 AM, the entity's field personnel informed its System Operator that it would be necessary to remove the entity's 240 kV transmission line from service to repair the 240 kV transmission line. The entity's System Operator studied the outage prior to the 240 kV transmission line being removed from service and determined there would not be any associated power flow or SOL exceedances. Thus, the entity removed its 240 kV transmission line from service around 12:30 PM and began making repairs. As the outages continued and load increased in the afternoon, the entity realized that the loss of a neighboring entity's 500 kV transmission line would load one of its 115 kV transmission lines within 12 MVA of its emergency thermal SOL. By 4:04 PM, the entity's Reliability Coordinator (RC) Real-Time Contingency Assessment (RTCA) tool informed the entity of a post-contingency SOL exceedance; specifically, the loss of the neighboring entity's 500 kV transmission line would result in a post-contingency flow on the aforementioned 115 kV transmission line, of 280 MVA which was 1.82% beyond its winter emergency Facility Rating limit. The entity's Systems Operators worked to address the issue by consulting two Operating Plans to determine the best solution based on the conditions. At 4:25 PM, the entity initiated its Operating Plan by coordinating with the neighboring entity's dispatcher to mitigate the SOL exceedance on the affected 115kV transmission line by relieving flow related to regional power transfers. At 4:53 PM, the neighboring entity was experiencing regional flow above its flowgate's total transfer capability (TTC). Reducing regional flow would have mitigated the SOL exceedance on the affected 115kV transmission line. At 7:08 PM, the entity coordinated with its RC and referenced the procedure from its Operating Plan, which addressed opening two of its separate 115kV transmission lines to mitigate a post contingency SOL exceedance on the affected 115kV transmission line at issue. However, doing so would split the entity's transmission network in the center. Before the System Operators began to open the two separate 115kV lines to mitigate the SOL exceedance on the 115kV transmission line at issue, system operations leadership instructed the System Operators to leave the entity's transmission system in its then-current configuration. Consequently, at 7:31 PM the entity informed its RC that it would take no further action to alleviate the SOL exceedance on the 115kV transmission line unless it experienced an actual contingency, at which point the entity would either issue its neighboring entity an Operating Instruction or proceed with splitting its own system. As a result, the SOL exceedance remained active until the condition cleared at 9:09 PM due to declining regional load after peak hours. Ultimately, the issue began when the entity did not take action to alleviate an SOL exceedance on one of its transmission lines on November 13, 2017 at 7:31 PM, and ended on November 13, 2017 at 9:09 PM, when there was no longer an SOL exceedance on its transmission line, for a total of 98 minutes. The root cause of the issue was attributed to the entity's management decision to wait to mitigate the post-contingency SOL exceedance through its own actions or by issuing Operating Instructions. However, the corrective actions were less than adequate. After reviewing all relevant information, WECC determined that the entity failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instructions, as required by TOP-001-3 R1.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to act to maintain the reliability of its Transmission Operator Area via its own actions or by issuing Operating Instruction as required by TOP-001-3 R1, related to an SOL exceedance on a 115 kV transmission line. Such failure could have resulted in instability on the line due to exceedance of Facility, voltage, and thermal ratings. In addition, such failure could lead to unplanned contingencies, or uncontrolled separation. As compensation, the entity had performed an operational planning analysis to identify next day pre-contingency or post-contingency overload issues. Additionally, workstations dedicated to the RC and the entity's Real-time Contingency Analysis (RTCA) are located at each System Operator's desk so that they could actively monitor the RC and the entity's RTCA results to ensure system reliability and acceptable pre-contingency and post-contingency system performance. Additionally, the entity had an EMS alarm in place that would alert the System Operator if the RC's RTCA results showed a new entry for a potential SOL exceedance on the entity's operating equipment or if a contingency showed a potential SOL exceedance on equipment operated by a neighboring entity. Furthermore, had the neighboring entity's 500kV line gone out of service, the entity would have corrected the condition by obtaining flow relief from the neighboring entity or reconfiguring its own transmission system to alleviate the potential overload aforementioned. No harm is known to have occurred. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) maintained the reliability of its TOP area; 2) performed an operational analysis in coordination with its neighboring entity to determine the availability of additional tools and operating procedures such as obtaining flow relief to support the System Operators in their reliable operation of the system; 3) reviewed and updated its own system operating procedures; its transmission system mitigation process operating plan was newly developed and its Transmission System Operation Guidelines were revised while its transmission operating plan was retired; and 4) developed and provided training to its System Operators and Management as to the required response to SOL exceedances, how its system is affected by flow through the neighboring entity's system, evaluations of potential SOL exceedance mitigation strategies, the conduct of network studies using the entities advance application tools, and lessons learned from the November 13, 2017 event activity. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019992	MOD-032-1	R2	sPower Services, LLC (SPS)	NCR11679	5/22/2017	6/2/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible or confirmed violation.)	On July 6, 2018, the SPS submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with MOD-032-1 R2. In October 2017, during an internal compliance assessment, SPS discovered it did not provide accurate steady-state, dynamics, and short circuit modeling data for a 300 MW solar generation Facility to its Transmission Planner (TP) and Planning Coordinator (PC) according to the data requirements and reporting procedures developed by its PC and TP in Requirement R1. Specifically, modeling data SPS provided to its TP and PC did not reflect all as-built conditions and the models were not validated within the appropriate timeline following TP procedure, resulting in SPS failing to provide validated models based on as-built conditions within 180 days of commercial operations. Once SPS discovered the potential noncompliance, it contacted the TP and maintained ongoing contact to ensure as-built models and validation would yield the most accurate possible results. This issue began on May 22, 2017, when SPS failed to provide its steady-state, dynamics, and short circuit modeling data for a 300 MW solar generation Facility to its PC and TP according to the data requirements and reporting procedures developed by its PC and TP and ended on June 2, 2018, when SPS provided updated and validated steady-state, dynamics, and short circuit modeling to the TP and PC based on as-built data for the 300 MW solar generation Facility, for a total of 377 days. The root cause of the issue was attributed to an incorrect assumption that model data based on as-built conditions should be submitted after phases of the project were complete, rather than 180 days after each individual phase was completed per the TP and PC procedure.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, SPS failed to provide accurate steady-state, dynamics, and short circuit modeling data for a 300 MW solar generation Facility to its TP and PC according to the data requirements and reporting procedures developed by its PC and TP in Requirement R1. Failure to provide accurate modeling data that reflects all the as-built conditions, could lead to the TP having an inaccurate view of the equipment capabilities and operating characteristics in transmission planning for the reliability of the BPS. In addition, the failure could have resulted in inaccurate operational oversight, if actual behavior of the BPS elements differed from the expected behavior, per the planning and operational model. However, SPS implemented weekly, biweekly, and monthly calls and emails with the TP and PC to coordinate the model development of the 300 MW solar generation Facility during the planning and construction phases of the project. Further, SPS has implemented good detective controls. Specifically, SPS conducts annual compliance reviews with the intent to assess compliance, develop controls, and collect evidence, this annual compliance review led to the discovery of this noncompliance. Additionally, as compensation, the Facility subject to this instance is a 300 MW solar generation Facility, and is not utilized as a firm resource, thereby reducing the risk. WECC considered SPS's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this issue, SPS has: i. provided updated and validated dynamic, steady-state, and short circuit modeling data to the TP and PC based on as-built data for the project; ii. incorporated model developed, validation and submittal into internal design, engineering and construction process flows; iii. iv. improved language in the SPS’s third-party engineering and construction contracts to ensure all necessary data is made available to update models within timelines required for compliance; v. created dedicated tasks in compliance tracking tool to ensure clear responsibility is assigned and that the due dates are met for MOD-032 requirements; vi. hosted an internal workshop with Compliance, Operations, Engineering and Interconnection teams to identify gaps in process and better define responsibility for managing the process to create, update and validate models; vii. held a dedicated webinar for the Compliance, Engineering and Interconnection teams to specifically review MOD-032; and viii. enhanced its existing compliance responsibility matrix to ensure there is both a primary and a back-up subject matter expert for MOD-032. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020259	TOP-001-3	R3	sPower Services, LLC (SPS)	NCR11679	5/19/2018	5/20/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On August 17, 2018, the SPS submitted a Self-Report stating that, as a Generator Operator (GOP), it was in noncompliance with TOP-001-3 R3. On May 20, 2018, SPS discovered it did not comply with an Operating Instruction issued by its Transmission Operator (TOP) for three solar generating Facilities totaling 162 MW. Specifically, on May 19, 2018 at 09:39 AM the TOP contacted SPS' Control Center (CC) to issue the Operating Instruction to change the power factor setpoint for the three solar generating Facilities from unity to 0.99 overexcite, the SPS CC Operator on shift complied with the instruction without issue. Historically, the TOP had removed similar Operating Instructions near the end of the solar production day, so at 7:57 PM, the SPS CC Operator on shift called the TOP to confirm the Operating Instruction was still in effect. At 7:59 PM, the TOP called SPS' CC and issued the Operating Instructions to return the three solar plants back to unity power factor. SPS's CC Operator made the necessary CC log entries in response and completed the necessary administrative responsibilities to lift the Operating Instructions by approximately 08:06 PM. However, the SPS CC Operator did not change the Supervisory Control and Data Acquisition (SCADA) power factor control setpoint for the plants from 0.99 overexcite back to unity, as instructed, resulting in SPS not complying with each Operating Instruction issued by its TOP. The following morning, on May 20, 2018, SPS's CC Operator did not notice that the three solar generating Facilities were still operating with an 0.99 overexcite power factor. At approximately 04:30 PM, SPS's CC manager noticed that the three solar generating Facilities had an 0.99 overexcite power factor without an active Operating Instruction indicated in SPS's CC log, so the CC Manager contacted the on shift SPS CC Operator. Subsequently, the on shift SPS CC Operator contacted the TOP to discuss the issue and reconfirmed the instruction to set the power factor setpoint for the three solar generating Facilities back to unity, after confirming the instruction, at approximately 04:30 PM, the on shift SPS CC Operator set the power factor for the three solar generating Facilities back to unity. This issue began on May 19, 2018 at 09:39 AM, when SPS failed to comply with its TOP Operating Instruction and ended on May 20, 2018 at 04:30 PM, when SPS's Operator changed the power factor setpoint for the three solar generating Facilities back to unity as requested by the TOP for a total of 18.51 hours. The root cause of the issue was attributed to the lack of procedures for executing Operating Instructions for solar plants that are not generating at the time Operating Instructions are received. Specifically, the Operator understood the need to follow Operating Instructions, but in this case did not know the procedure to execute the necessary SCADA command to carry out the instruction. Contributing factors to this oversight were that none of the solar generating Facilities were generating at the time and the CC Operator was not accustomed to receiving Operating Instructions for non-generating solar plants.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the BPS. In this instance, SPS failed to comply with each Operating Instruction issued by its TOP for three solar generating Facilities for 18.51 hours. Failure to provide to comply with each Operating Instruction issued by its TOP could result in the TOP being unaware of the state of the GOP's solar plants, specifically being unaware of the amount of voltage support provided by the solar plants. This could potentially lead to voltage issues on the TOP's system. However, SPS implemented good detective controls to detect this issue. Specifically, SPS Operator's log any received Operating Instructions in the control room log the CC manager completes a monthly checklist for reviews of all Operating Instructions received during the month, this review led to the discovery of this noncompliance. Additionally, the solar plants provide minimal voltage support to the TOP, further reducing the risk. WECC considered SPS's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this issue, SPS has: ix. created an operating procedure for power factor setpoint change Operating Instructions for the three solar generating Facilities; x. reviewed the circumstances of the event with all SPS Control Center Operators and provided training about the need to diligently follow all internal processes surrounding responding to Operating Instructions; and xi. implemented mandatory twice daily review and logging of key SCADA setpoints and operating data related to voltage and power factor control. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020635	PRC-019-2	R1.; R1.1.; R1.1.1.; R1.1.2.	Solar Star California XIX, LLC (SSCA)	NCR11424	07/01/2016	01/04/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible or confirmed violation.)	On November 5, 2018, SSCA submitted a Self-Report stating that, as a Generator Owner, it was in potential noncompliance with PRC-019-2 R1. Specifically, on November 5, 2018, SSCA discovered it did not coordinate the voltage regulating system controls with the applicable equipment capabilities and settings of the applicable Protection System devices and functions for its 318 MW solar generation Facility by July 1, 2016, as required by the Implementation Plan for PRC-019-2. SSCA contacted a third-party vendor tasked with performing the coordination study three months prior to the mandatory and effective date of the Standard, but incorrectly assumed that the coordination study for its solar generation Facility would be provided prior to July 1, 2016, which has been determined to the be the root cause of this noncompliance. This issue began on July 1, 2016, when the Standard became mandatory and enforceable and ended on January 4, 2017, when SSCA completed its coordination analysis review, for a total of 188 days. After reviewing all relevant information, WECC Enforcement determined that SSCA failed to properly perform PRC-019-2 R1.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, SSCA failed to coordinate the voltage regulating system controls, (including in-service limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices for one solar generating Facility and functions by July 1, 2016 as required by the Implementation Plan for the Standard. SSCA’s failure to coordinate the voltage regulating system controls and protection systems could have resulted in the solar generation Facility being damaged or tripping unintentionally during a voltage excursion. However, when SSCA operated, no trips occurred due to inadequate coordination and when SSCA performed the verification, no changes were required. In addition, SSCA contributes only 318 MVA to the grid when operating and is not a firm resource, further reducing the risk. No harm is known to have occurred. WECC considered SSCA's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this issue, SSCA has: a. completed the coordination analysis of the voltage regulating system controls, equipment capabilities and settings of the applicable Protection System devices and functions for its single solar generating Facility; b. created reminder notifications in its tracking system to review coordination analysis and update as needed within the five-year period required by PRC-019-2; and c. set reminder notifications to launch six months prior to the due date to compensate for any unforeseen delay. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2019021637	PRC-024-2	R2	Solar Star California XIX, LLC (SSCA)	NCR11424	07/01/2016	08/14/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On June 3, 2019, SSCA submitted a Self-Report stating that, as a Generator Owner, it was in potential noncompliance with PRC-024-2 R2. Specifically, during its annual compliance review, SSCA discovered it did not set its protective relaying such that the generator voltage protective relaying did not trip the applicable generating unit as a result of a voltage excursion (at the point of interconnection) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024-2 Attachment 2, for a 318 MW solar generation Facility and for inverters totaling 279 MW of solar generation. Prior to the of July 1, 2016 effective date, SSCA performed a PRC-024-2 analysis that indicated SSCA was compliant with voltage ride-through requirements. However, on November 16, 2017, after further review, SSCA realized that the prior analysis was based on the improper assumption that the on-load transformer tap changer would regulate the inverter voltage, which has been determined to be the root cause of this noncompliance. As a result, SSCA did not set over-voltage protection settings on 427 inverters in a way that would prevent them from tripping in response to qualifying overvoltage events. This issue began on July 1, 2016, when the Standard became mandatory and enforceable and ended on August 14, 2019, when SSCA updated the over-voltage settings for its 427 inverters, for a total of 1140 days. After reviewing all relevant information, WECC Enforcement determined that SSCA failed to properly perform PRC-024-2 R2.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the BPS. In this instance, SSCA failed to set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit as a result of a voltage excursion (at the point of interconnection) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2, for 427 inverters at a single solar generation Facility. SSCA's failure to set voltage protective relaying properly could have reasonably resulted in unintended protective action to remove 597 MW of generation during a high-voltage excursion. However, as compensation, SSCA calculates the relevant settings based on conservative assumptions, such as using the worst-case voltage drop between any inverter and the point of interconnection for all of its inverters. In addition, when SSCA operated, no tripping events occurred due to voltage excursions. Furthermore, SSCA contributes only 318 MW to the grid when operating and is not a firm resource, further reducing the risk. No harm is known to have occurred. WECC considered SSCA's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this issue, SSCA has: i. procured the updated analysis specifically addressing the incorrect assumption from the previous analysis of its unit's over-voltage settings; and ii. updated the over-voltage settings on all 427 inverters on its single solar generation Facility. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020634	PRC-019-2	R1.; R1.1.; R1.1.1.; R1.1.2.	Solar Star California XX, LLC (SSXX)	NCR11432	07/01/2016	01/04/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On November 5, 2018, SSXX submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2 R1. Specifically, on November 5, 2018, SSXX discovered it did not coordinate the voltage regulating system controls with the applicable equipment capabilities and settings of the applicable Protection System devices and functions for its 279 MW solar generation Facility by July 1, 2016, as required by the Implementation Plan for PRC-019-2. SSXX contacted a third-party vendor tasked with performing the coordination study three months prior to the mandatory and effective date of the Standard, but incorrectly assumed that the coordination study for its solar generation Facility would be provided prior to July 1, 2016, which has been determined to the be the root cause of this noncompliance. This issue began on July 1, 2016, when the Standard became mandatory and enforceable and ended on January 4, 2017, when SSXX completed its coordination analysis review, for a total of 188 days. After reviewing all relevant information, WECC Enforcement determined that SSXX failed to properly perform PRC-019-2 R1.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, SSXX failed to coordinate the voltage regulating system controls, (including in-service limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices for one solar generating Facility and functions by July 1, 2016 as required by the Implementation Plan for the Standard. SSXX's failure to coordinate the voltage regulating system controls and protection systems could have resulted in the solar generation Facility being damaged or tripping unintentionally during a voltage excursion. However, when SSXX operated the Facility, no trips occurred due to inadequate coordination and when SSXX performed the verification, no changes were required. In addition, SSXX contributes only 279 MVA to the grid when operating and is not a firm resource, further reducing the risk. No harm is known to have occurred. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this issue, SSXX has: a. completed the coordination analysis of the voltage regulating system controls, equipment capabilities and settings of the applicable Protection System devices and functions for its single solar generating Facility; b. created reminder notifications in its tracking system to review coordination analysis and update as needed within the five-year period required by PRC-019-2; and c. set reminder notifications to launch six months prior to the due date to compensate for any unforeseen delay. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2019021636	PRC-024-2	R2	Solar Star California XX, LLC (SSXX)	NCR11432	07/01/2016	08/14/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible or confirmed violation.)	On June 3, 2019, SSXX submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R2. Specifically, during its annual compliance review, SSXX discovered it did not set its protective relaying such that the generator voltage protective relaying did not trip the applicable generating unit as a result of a voltage excursion (at the point of interconnection) caused by an event on the transmission system external to the generating plant that remains within the “no trip zone” of PRC-024-2 Attachment 2, for a 279 MW solar generation Facility and for inverters totaling 318 MW of solar generation. Prior to the of July 1, 2016 effective date, SSXX performed a PRC-024-2 analysis that indicated SSXX was compliant with voltage ride-through requirements. However, on November 16, 2017, after further review, SSXX realized that the prior analysis was based on the improper assumption that the on-load transformer tap changer would regulate the inverter voltage, which has been determined to be the root cause of this noncompliance. As a result, SSXX did not set over-voltage protection settings on 234 inverters in a way that would prevent them from tripping in response to qualifying overvoltage events. This issue began on July 1, 2016, when the Standard became mandatory and enforceable and ended on August 14, 2019, when SSXX updated the over-voltage settings for its 234 inverters, for a total of 1140 days. After reviewing all relevant information, WECC Enforcement determined that SSXX failed to properly perform PRC-024-2 R2.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the BPS. In this instance, SSXX failed to set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit as a result of a voltage excursion (at the point of interconnection) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2, for 234 inverters at a single solar generation Facility. SSXX’s failure to set voltage protective relaying properly could have reasonably resulted in unintended protective action to remove 597 MW generation during a high-voltage excursion. However, as compensation, SSXX calculates the relevant settings based on conservative assumptions, such as using the worst-case voltage drop between any inverter and the point of interconnection for all of its inverters. In addition, when SSXX operated, no tripping events occurred due to voltage excursions. Furthermore, SSXX contributes only 279 MW to the grid when operating and is not a firm resource, further reducing the risk. No harm is known to have occurred. WECC considered SSXX's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this issue, SSXX has: i. procured the updated analysis specifically addressing the incorrect assumption from the previous analysis of its unit’s over-voltage settings; and ii. updated the over-voltage settings on all 234 inverters on its single solar generation Facility. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2019021299	COM-001-2.1	R11	Sycamore Cogeneration Company (SYCC)	NCR05417	2/13/2017	2/13/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On April 3, 2019, SYCC submitted a Self-Report stating, as a Generator Operator, it was in potential noncompliance with COM-001-2.1 R11. On January 23, 2019, during a third-party NERC program analysis, SYCC discovered that on February 13, 2017, at 1:39 AM, it did not notify its Balancing Authority (BA) or Transmission Operator (TOP) when its control room phone system was lost due to the failure of the uninterruptable power supply, which ended on the same day at 06:20 AM, when power was restored to the control room desk phone, for a total of 4 hours and 41 minutes. However, SYCC did notify its Scheduling Coordinator of the communication loss. The root cause of the issue as attributed to SYCC's COM-001 procedure and training document did not identify the control room phone as a COM-001 Interpersonal Communication device and did not include clearly defined steps for communication upon the loss of the desk phone. As a result, SYCC's Operations personnel were not aware of the requirements to notify its BA and TOP. This noncompliance started on February 13, 2017 at 1:39 AM, when SYCC failed to notify its Balancing Authority (BA) or Transmission Operator (TOP) when its control room phone system was lost and ended on the same day at 6:20 AM, when power was restored to the control room desk phone, for a total of 4 hours and 41 minutes. After reviewing all relevant information, WECC Enforcement determined that SYCC failed to effectively perform COM-001-2.1 R11.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, SYCC failed to consult its BA and TOP affected by the failure of its Interpersonal Communication capability to determine a mutually agreeable action for the restoration of its Interpersonal Communication capability. Failure to consult with entities affected by the loss of Interpersonal Communications capability could result in these affected entities being unaware of the loss of communications and being unable to effectively communicate Operating Instructions or other measures necessary to maintain reliability. As compensation, SYCC did notify its Scheduling Coordinator when the control room phone lost power ensuring that the coordinator would not issue any Operating Instructions during this period. Also, a search of the market notice records confirmed that no Ancillary Services scarcity events coincided with the date of loss of Interpersonal Communication. Additionally, SYCC contributes a total of 300 MW of generation to the grid, further reducing the risk. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, SYCC: 1) updated COM-001 procedure and training materials to identify the control room desk phone as the single interpersonal communication capability device and include defined steps for communication upon loss of interpersonal communication capability; 2) implemented the use of a loss of Interpersonal Communication form to streamline the process of notifying affected entities of phone loss and to log details appropriately. 3) provided COM specific training to all Operations Personnel; and 4) confirmed all Operations Personnel reviewed and acknowledged training materials. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2019020996	MOD-025-2	R1	Kansas City Power & Light Company (KCPL)	NCR01107	07/01/2016	07/18/2016	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 14, 2019, KCPL submitted a Self-Log stating that as a Generator Owner, it was in noncompliance with MOD-025-2 R1. KCPL reported that it did not communicate test results for two generating unit(s) to the Transmission Planner within the required 90-day timeframe; however, KCPL scheduled testing for 18 applicable unit(s) to meet the 40% phased implementation requirement prior to the July 1, 2016 enforcement date. While the 18 unit(s) were tested prior to July 1, 2016, the test reports for Northeast Power Plant Units #13 and #14 were not provided to the Transmission Planner within the required 90 calendar day time-frame per MOD-025-2 R1.2. The cause of the noncompliance was that KCPL failed to ensure that its third-party contractor provided test results on time to meet the 90 calendar day time-frame per MOD-025-2 R1.2. The noncompliance began on July 1, 2016, when the Standard and Requirement became enforceable, and ended 18 days later on July 18, 2016, when the test reports were provided to the Transmission Planner.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. KCPL reported that the issue affected two gas generation unit(s) with nameplate ratings of 50 MW, representing less than 2% of KCPL's fleet nameplate capacity (approximately 8000 MW). The size of the two unit(s) limits the potential impact of inaccurate capabilities in KCPL's planning models and neither units were Blackstart Resources or part of an Interconnection Reliability Operating Limit or Remedial Action Scheme. Further, as a result of the capability verifications, the real power capacity was increased in the planning model for both unit(s), while the primary risk addressed by the Standard is capacity shortfalls resulting from actual unit capabilities that are less than indicated in planning models. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, KCPL: 1) provided the required MOD-025-2 form, showing different generator parameters, to the Transmission Planner; 2) instituted monthly meetings to review MOD-025-2 activities including scheduled testing, communication requirements, issue mitigation, lessons learned and other related activities; 3) created additional controls to ensure the completion of all MOD-025-2 requirements, including a MOD-025-2 Tracking Worksheet and assigned workflows to track communication and due dates between the generation engineering and transmission planning groups; and 4) expanded the duties of the Generation Compliance Specialist position to include responsibility for assisting the generation business unit with meeting compliance with Operations & Planning requirements in addition to CIP requirements.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020128	IRO-010-2	R3	Southwestern Power Administration (SWPA)	NCR01144	03/07/2018	10/19/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 28, 2018, SWPA submitted a Self-Report stating that as a Transmission Operator, it was in noncompliance with IRO-010-2 R3. The Self-Report included three instances of noncompliance. In the first instance of noncompliance, SWPA reported that it did not notify the Southwest Power Pool (SPP) Reliability Coordinator (RC) of an Inter-Control Center Communications Protocol (ICCP) outage per the SPP RC data specification. The cause of the noncompliance was SWPA misinterpreted the requirements of the SPP Balancing Authority (BA) and RC Reliability Data Specifications (RDS). SWPA's process was to notify the BA & RC only if an outage lasted 30 minutes or longer, while the RDS required notification for all outages, regardless of duration. In the second and third instances of noncompliance, SWPA reported that phone call notifications were used rather than email communication as specified in the RDS for RC notifications of intermittent Remote Terminal Unit outages. The cause of the noncompliances was SWPA failed to follow the documented RDS procedure, which indicates that the primary method of communicating outages to the RC is via email. The noncompliance began on March 7, 2018, when SWPA did not follow their procedure for notifying their RC of an ICCP outage, and ended October 19, 2018, when the final instance of failing to follow the documented protocols occurred.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In the first instance, SWPA reported that it had full visibility and control over its facilities during the unplanned outage period and the outage was limited to ICCP data being exchanged with the SPPNet (SPP RC). This ICCP outage duration was limited to 24 minutes. NERC Standard TOP-001-3 R9 requires notification to the RC for unplanned outages of 30 minutes or more. Therefore, this event did not require reporting per TOP-001-3 R9, and only poses a noncompliance in regards to meeting the reporting requirements of the RDS, which require reporting of all unplanned outages, regardless of duration. It is reasonable to assume that for outages of less than 30 minutes, the notification is primarily for the RC's awareness and not because RC action is required. In the second instance, SWPA reported that SPP RC was notified of the intermittent RTU outages. However, the notification was provided via phone and not via email communication that was specified in SPP RC's RDS. Additionally, the intermittent RTU outages were limited to a duration of one hour and three minutes. In the third instance, SWPA reported that SPP RC was notified of the intermittent RTU outages. However, the notification was provided via phone and not via email communication that was specified in SPP RC's RDS. Additionally, the intermittent RTU outages were limited to a duration of one hour and twelve minutes. No harm is known to have occurred. SWPA has no relevant history of noncompliance.
Mitigation	To mitigate the first instance of noncompliance, SWPA: 1) implemented a new SCADA alarming tool for ICCP outages; 2) held an all-hands meeting to demonstrate the new alarming functionality and instruct dispatchers on the required reporting process; and 3) implemented a "Dispatch Standing Order" with instructions for unplanned ICCP outages, including notification to the RC. To mitigate the second and third instances of noncompliance, SWPA: 1) held an all-hands meeting to reinforce the requirement that dispatchers notify the RC via the required email address for outages that require reporting per the SPP RDS.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020618	EOP-005-2	R16	Westar Energy, Inc. (WR)	NCR00658	01/01/2017	10/01/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On November 1, 2018, WR submitted a Self-Report stating that as a Generator Operator, it was in noncompliance with EOP-005-2 R16. WR reported that it did not perform Blackstart Resource tests for its Hutchinson Energy Center (HEC) CT-4 in accordance with the testing requirements set by the Transmission Operator (TOP). WR determined that the HEC CT-4 was identified as a Blackstart Resource in its Westar Blackstart Plan from January 1, 2014 until October 1, 2018. HEC CT-4 was tested in accordance with the TOP's requirements in 2013, and was due for testing again in 2016, however that testing did not occur. The cause of the noncompliance was due a misunderstanding between WR's transmission and generation departments regarding a unit that was listed as a Blackstart Resource and was scheduled to retire. The noncompliance began on January 1, 2017, when the Blackstart Resource was not tested in 2016 per the TOP's requirements, and ended on October 1, 2018, when HEC CT-4 had its Blackstart Resource designation removed in the Westar Blackstart Plan.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Per WR, the unit of issue had been tested three times and the tests indicated that the unit was capable of running if needed. Also, no events occurred during the period of noncompliance that required the operation of any of the Blackstart units. WR verified through its 2016 planning study that its existing Blackstart Resources were sufficient in assuming the retirement of HEC CT-4. Therefore, WR did not consider HEC CT-4 a required resource in the Blackstart plan. No harm is known to have occurred. WR has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, WR: 1) revised Blackstart Plan which removed Blackstart Resource designation; 2) instituted a new transmission and generation coordination meeting to discuss Blackstart resource testing, training, and other Blackstart related logistics; 3) consolidated blackstart testing requirements into the Evergy Generation testing database to be reviewed by a compliance specialist and plant management on a monthly basis to ensure that testing requirements are met throughout the year; and 4) incorporated all Blackstart units into the Testing Database which manages the periodic testing by displaying the unit's next test date.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019021149	MOD-032-1	R2.	Sheldon Energy, LLC	NCR10299	10/27/2017	11/10/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On March 4, 2019, after receiving an Audit notification from NPCC that included MOD-032-1 [Requirement R2.], Sheldon Energy, LLC ("the Entity") submitted a Self-Report stating that, as a Generator Owner (GO), it had discovered on December 15, 2016, through an internal compliance review, that it was in noncompliance with MOD-032-1 R2. Specifically, the Entity had not submitted steady-state, dynamics, and short circuit modeling data for its facilities in accordance with the data requirements and reporting procedures developed by its Planning Coordinator (PC) and Transmission Planner (TP), the NYISO. The NYISO is also the Entity's Reliability Coordinator (RC). This noncompliance started on October 27, 2017, when the Entity failed to provide data before the final data submittal deadline established by its TP/PC's reporting procedure, and ended on November 10, 2017, when the Entity submitted modeling data for its generating facilities to its TP/PC. The root cause of this instance of noncompliance was a failure in the Entity's Compliance Policy. It lacked the details and controls required to help ensure compliance with the NERC standards such as timely submission of modeling data reporting required by this standard. Additionally, the entity was unaware of the compliance contact information at the TP/PC to submit the modeling data for its generating facilities.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). A failure to report modeling data in a timely manner could result in a delayed, outdated or inaccurate assessment of the reliability of the interconnected transmission system. The Entity's generating facilities consist of 75 wind turbine generators with an aggregate rated capacity of 112.5 MW, which are interconnected via a collector bus and step-up transformer to a 230kV substation owned by its host Transmission Owner. The Entity had provided modeling data for its facilities in early 2008 as part of required system reliability impact studies performed by its TP/PC prior to achieving commercial operation in March 2009. The original modeling data is still a valid representation today, as the Entity has not modified its original electrical equipment. The Entity's generating facilities have a rated capacity that is approximately 6% of its RC's 1965 MW required Operating Reserves and generally operate at an average 27% annual capacity factor. Therefore, the Entity's RC could have adequately compensated for a potential generation outage arising from this instance of noncompliance. Additionally, the noncompliance was of short duration (14 days). No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined there are no prior relevant instances of noncompliance.
Mitigation	To mitigate the noncompliance, the Entity: 1. submitted steady-state, dynamics, and short circuit modeling data to its TP/PC; 2. developed a list of contacts for all 3rd party compliance entities (TP, PC, etc.) that is reviewed for accuracy, as necessary, by the NERC Compliance Team; 3. expanded its compliance team by two new members in order to better manage compliance tasks; 4. created an automated task notification in its internal task management system to send reminders to responsible SMEs 60 days prior to the required completion date. Additionally, the task is referred to the compliance team if not completed within 30 days of the due date; and 5. enhanced its existing internal Compliance Calendar, located on its Share Point Compliance site, by adding an item that specifically highlights upcoming compliance tasks related to MOD-032-1.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020639	PRC-001-1.1(ii)	R3	American Electric Power Service Corporation as agent for etc.	NCR00682	10/16/2017	7/27/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On October 29, 2018, the entity submitted a Self-Report stating that, as a Transmission Operator (TOP), it was in noncompliance with PRC-001-1.1(ii) R3. This noncompliance involves two separate incidents where the entity did not coordinate protective system changes with neighboring TOPs on 138kV interconnected lines. On February 7, 2018, the entity discovered the first incident. More specifically, a protection engineer performing an internal control for relay changes detected the issue. In the first incident, on October 16, 2017, the entity made protective system changes on a 138kV interconnected line and did not coordinate those changes with the neighboring TOP and Balancing Authority (BA) (Duke) prior to implementation in the field. The project involved a four terminal 138kV line. The entity owned three of the terminals and was upgrading relays. (The entity was replacing electromechanical relays with digital relays. The settings on the new digital relays were very similar to the settings on the electromechanical relays.) A neighboring TOP and BA owned the fourth terminal. The entity outsourced the work to an independent engineering company, and the engineering company failed to coordinate with the neighboring TOP and BA prior to implementation. The entity failed to provide sufficient oversight to ensure proper coordination occurred. The entity coordinated the change on March 22, 2018. It should be noted that even with the changes, the neighboring TOP and BA was not required to change its protection system settings based on the entity's changes. On June 11, 2018, an entity engineer discovered the second incident while preparing for an audit. In the second incident, the entity failed to coordinate with the neighboring TOP (NIPSCO) regarding a 138kV interconnect project. The project involved a single firmware upgrade, and as part of the firmware upgrade, the entity did not intend to change protection settings. Similar to the prior incident, the entity outsourced the work to an independent engineering company. For this incident, implementation occurred on June 6, 2018, and the entity did not properly coordinate until July 27, 2018. It should be noted that even with the firmware and setting changes, the neighboring TOP was not required to change its protection system settings based on the entity's upgrade. The root cause of this noncompliance is the entity failing to monitor and ensure that its engineering contractor notified the affected TOPs and BAs of the implementation of certain protective system changes. This noncompliance involves the management practices of external interdependencies and verification. External interdependencies is involved because both incidents resulted from the failure of an independent engineering company upon whom the entity relied to comply with the coordination requirements of protection system changes. Verification is involved in both instances because the entity did not have a verification control in place to ensure that the engineering company properly coordinated the protection system changes. The first incident of this noncompliance started on October 16, 2017, when the entity implemented protection system changes without notifying the TOP and BA and ended on March 22, 2018, when the entity coordinated with the TOP and BA. The second incident of this noncompliance began on June 6, 2018, when the entity implemented protection system changes without notifying the TOP and ended on July 27, 2018, when the entity coordinated with the TOP.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS) based on the following factors. If protective system changes are not coordinated, there is an increased likelihood of unexpected tripping, misoperation, and delayed restoration. The risk is minimized based on the following facts. In the first incident, the entity effectively identified and corrected the issue through the use of an internal control. Further, the settings on the new digital relays were very similar to the settings on the electromechanical relays, thus reducing the risk of miscoordination. In the second incident, the entity was implementing a single firmware upgrade and although settings were changed, the changes were minimal, thus reducing the risk. Additionally, upon coordinating with the neighboring entity in both incidents, neither was required to make changes to its protection system settings based on the entity's changes (i.e., the lack of coordination did not result in any increased risk to the BPS). No harm is known to have occurred. The entity has relevant compliance history. However, ReliabilityFirst determined that the entity's compliance history should not serve as a basis for applying a penalty because the prior noncompliance involved different facts and circumstances.
Mitigation	To mitigate this noncompliance, the entity: 1) performed an extent of condition by providing and reviewing a list of all new protective systems and protective system changes with neighboring Transmission Operators and Balancing Authorities within RF; 2) mitigated the noncompliance by coordinating with Duke on March 22, 2018 and coordinating with NIPSCO on July 27, 2018. The entity notified PJM via the monthly shared Coordinations List in June 2018; 3) disseminated a PRC-001 newsletter article to the entity's applicable personnel and to the independent engineering companies that are responsible for relay settings. The newsletter article was used as a lessons learned to bring awareness to the importance of PRC-001; 4) stressed the need to coordinate settings prior to implementing the changes, during an established quarterly Protection and Control meeting with all applicable entity personnel and independent engineering companies;

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020639	PRC-001-1.1(ii)	R3	American Electric Power Service Corporation as agent for etc.	NCR00682	10/16/2017	7/27/2018	Self-Report	Completed
			5) developed and disseminated PRC-001 training to all applicable personnel. The training will be provided on an annual basis going forward; 6) performed an extent of condition within MRO to confirm all new protective system and protective system changes on interconnected lines were coordinated with neighboring TOPs and BAs form January 2017 to February 2019. (The entity performed a similar extent of condition review in RF as part of the first Milestone.); and 7) created a master interconnection list that will help increase operational awareness and help to reduce errors by driving interconnection identification consistency.					

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020640	PRC-001-1.1(ii)	R3	American Electric Power Service Corporation as agent for etc.	NCR00682	3/8/2017	10/3/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On October 29, 2018, the entity submitted a Self-Report stating that, as a Transmission Operator (TOP), it was in noncompliance with PRC-001-1.1(ii) R3. On February 7, 2018, an independent engineering company notified the entity of two instances of protective system changes that were not coordinated with the neighboring TOP and Balancing Authority (BA) (Western Farmers Electric Cooperative (WFEC)). The independent engineering company that the entity hired to perform the changes failed to coordinate changes on two interconnected 138kV lines within the same substation. The project involved upgrading hardware and firmware. Protection system settings were not changed. The root cause of this noncompliance was that the entity did not have a proper control in place to confirm that the engineering company was coordinating with the entity's neighboring TOPs and BAs prior to implementing changes to protective systems. This noncompliance involves the management practices of external interdependencies and verification. External interdependencies is involved because the noncompliance resulted from the failure of an independent engineering company upon whom the entity relied to comply with the coordination requirements of protection system changes. Verification is involved because the entity did not have a verification control in place to ensure that the engineering company properly coordinated the protection system changes. This noncompliance started on March 8, 2017, when the entity implemented protection system changes without notifying the TOP and the BA and ended on October 3, 2017, when the entity coordinated with the TOP and the BA regarding the protective system changes.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. If protective system changes are not coordinated, there is an increased likelihood of unexpected tripping, misoperation, and delayed restoration. The risk is minimized because the entity was upgrading hardware and firmware but was not changing any protection system settings, thus reducing the risk of miscoordination. It is worth noting that upon coordination, the neighboring entity was not required to make changes to its protection system settings based on the entity's changes. No harm is known to have occurred. The entity has relevant compliance history. However, ReliabilityFirst determined that the entity's compliance history should not serve as a basis for applying a penalty because the prior noncompliance involved different facts and circumstances. More specifically, the prior noncompliance involved an entity engineer implementing setting changes. The current noncompliance, in contrast, involves the entity's oversight of a contractor.
Mitigation	To mitigate this noncompliance, the entity: 1) performed an extent of condition by providing and reviewing a list of all new protective systems and protective system changes with neighboring Transmission Operators and Balancing Authorities within RF; 2) mitigated the noncompliance by completing coordination with WFEC on October 3, 2017. The entity notified PJM via the monthly shared Coordinations List in June 2018; 3) disseminated a PRC-001 newsletter article to the entity's applicable personnel and to the independent engineering companies that are responsible for relay settings. The newsletter article was used as a lessons learned to bring awareness to the importance of PRC-001; 4) stressed the need to coordinate settings prior to implementing the changes, during an established quarterly Protection and Control meeting with all applicable entity personnel and independent engineering companies; 5) developed and disseminated PRC-001 training to all applicable personnel. The training will be provided on an annual basis going forward; 6) performed an extent of condition within MRO to confirm all new protective system and protective system changes on interconnected lines were coordinated with neighboring TOPs and BAs from January 2017 to February 2019. (The entity performed a similar extent of condition review in RF as part of the first Milestone.); and 7) created a master interconnection list that will help increase operational awareness and help to reduce errors by driving interconnection identification consistency.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019785	PER-005-2	R2	City of Rochelle	NCR00721	7/1/2016	Present	Compliance Audit	12/31/2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On May 18, 2018, ReliabilityFirst determined that the entity, as a Transmission Owner, was in noncompliance with PER-005-2 R2 identified during a Compliance Audit conducted from September 28, 2017 through May 4, 2018. The entity contracts Gridforce Energy Management (Gridforce) to provide System Operator function. During the audit, ReliabilityFirst discovered that the entity did not determine its company-specific Real-time reliability-related task list based on a defined methodology. In addition, the entity did not ensure that the actions and training provided by Gridforce, or to Gridforce System Operators, addressed those specific risks. (ReliabilityFirst determined that the PJM matrix does not cover this situation and that the entity, as a registered Transmission Owner, is expected to meet the expectation of identifying its Bulk Electric System company-specific Real-time reliability-related tasks. In addition, the act of outsourcing the System Operator activities to Gridforce did not transfer the compliance obligations and risk for the R2 activities. In summary, ReliabilityFirst expects that the entity would determine its company-specific Real-time reliability-related task list, based on a defined methodology, and then ensure that the actions and training provided by Gridforce to Gridforce System Operators addressed those risks.) The root cause of this non-compliance was the entity's mistaken belief that simply outsourcing System Operator activities to Gridforce satisfied its compliance obligations under PER-005-2 R2. This root cause involves the management practices of workforce management and external interdependencies. Workforce management is involved because the entity's employees were not fully aware of their compliance obligations under the Standard. External interdependencies is involved because mitigating the risk in this case involves enhancing controls around monitoring Gridforce's performance of its contracted activities. This noncompliance started on July 1, 2016, when the entity was required to comply with PER-005-2 R2 and is expected to end on December 31, 2019, when the entity will document its methodology for determining its company-specific Real-time reliability-related task list.
Risk Assessment	ReliabilityFirst determined that the subject noncompliance posed a minimal risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by not ensuring that the actions and training provided addressed company-specific Real-time reliability-related task list is that doing so increases the likelihood that System Operators may not be prepared to perform reliability-related tasks and could therefore put the BPS at risk. This risk was mitigated in this case by the following factors. First, Gridforce is staffed with NERC Reliability Coordinator and PJM Transmission certified System Operators, increasing the likelihood that they would be able to perform the reliability-related tasks. Second, the entity has a small peak load (52 MW) and limited equipment, which mitigates the potential impact of this risk. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) developed and documented, in coordination with Gridforce, the entity's methodology for determining its company-specific Real-time reliability-related task list. To mitigate this noncompliance, the entity will complete the following mitigation activities by December 31, 2019: 2) will review the task list every 6 months to ensure its accuracy.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019786	PER-005-2	R3	City of Rochelle	NCR00721	7/1/2016	Present	Compliance Audit	12/31/2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On May 18, 2018, ReliabilityFirst determined that the entity, as a Transmission Owner, was in noncompliance with PER-005-2 R3 identified during a Compliance Audit conducted from September 28, 2017 through May 4, 2018. During the audit, ReliabilityFirst determined that the entity did not provide evidence that it delivered the requisite training tailored to meet the entity's company-specific Real-time reliability-related tasks (RRTs). Rather, the entity provided only a document that discussed training relating to the RRTs, and ReliabilityFirst determined that that evidence was insufficient both substantively and procedurally (i.e., it did not include training logs with dates to adequately demonstrate delivery). The root cause of this noncompliance was the entity's incorrect reliance on Gridforce Energy Management (Gridforce) to deliver the requisite training. This root cause involves the management practices of workforce management and external interdependencies. This noncompliance started on July 1, 2016, when the entity was required to comply with PER-005-2 R3 and is expected to end on December 31, 2019, when the entity will ensure that all Gridforce system operators are appropriately trained.
Risk Assessment	ReliabilityFirst determined that the subject noncompliance posed a minimal risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by not ensuring that the actions and training provided addressed company-specific Real-time reliability-related task list is that doing so increases the likelihood that System Operators may not be prepared to perform reliability-related tasks and put the BPS at risk. This risk was mitigated in this case by the following factors. First, Gridforce is staffed with NERC Reliability Coordinator and PJM Transmission certified System Operators, increasing the likelihood that they would be able to perform the reliability-related tasks. Second, the entity has a small peak load (52 MW) and limited equipment, which mitigates the potential impact of this risk. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity will complete the following mitigation activities by December 31, 2019: 1) will establish and document, in coordination with Gridforce, a training process to ensure all Gridforce system operators are appropriately trained; 2) will ensure that the training has been delivered to all Gridforce system operators; and 3) will implement an internal control to ensure that future training is delivered at appropriate time intervals.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019021200	MOD-027-1	R3	Dearborn Industrial Generation, L.L.C.	NCR00751	10/18/2018	12/3/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On March 5, 2019, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-027-1 R3. The entity did not provide a written response to its Transmission Planner (ITC), within 90 calendar days of receiving written notification from ITC that the entity's turbine/governor, and load control model was not "usable" without further information. The entity did not provide a written response until the 137 day mark. On June 25, 2018, the entity provided ITC with a verified turbine/governor control model for each of the entity's units, including documentation and data. ITC confirmed receipt of the model for the entity as well as those from affiliated entities Livingston Generating Station (LGS) and Kalamazoo River Generating Station (KRGS). On July 19, 2018, ITC reported its findings as to the usability of the models submitted: (a) KRGS' model was sufficient; (b) LGS' model failed, and (c) A portion of the entity's model run failed (the combustion turbine units). ITC then requested a solution for the failed LGS and entity models. (From June to August 2018, staff worked with the Transmission Planner and its testing vendor to resolve the model issues for LGS.) On December 3, 2018, ITC asked about the status of the entity model and the entity immediately provided the necessary clarification that day. On December 5, 2018, ITC confirmed that the entity model ran successfully. The root cause of this noncompliance was inadequate work management and process controls resulting in entity staff focusing resources on remedying the LGS model, and overlooking the entity model. This resulted in the entity failing to provide the necessary clarification within 90 days. This noncompliance involves the management practices of work management and workforce management. Work management is involved in this noncompliance because the entity failed to properly prioritize the clarification of the entity model. Workforce management is involved in this noncompliance because entity staff did not properly balance the workload between the LGS model failure and the entity model clarification. This noncompliance started on October 18, 2018, when the entity failed to submit a written response to the Transmission Planner as required and ended on December 3, 2018, when the entity submitted a written response to the Transmission Planner.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by this noncompliance arises from allowing dynamic simulations that assess BPS reliability to inaccurately represent generator unit real power response to system frequency variations. That can lead to Transmission Planners operating the BPS with inaccurate information. The risk is minimized because the duration was just 47 days. Further minimizing the risk, the entity's clarification to the model was minimal. Additionally, on a follow-up request of ITC after the 90 day period to respond expired, the entity provided ITC the necessary clarification on the same day. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) included tracking compliance information requests in the Compliance Assurance Tracking System (CATS). The CATS will automatically alert task assignees of approaching due dates and assist in tracking compliance activities to better assure timely completion and prevent a recurrence of this issue; and 2) issued a letter to the Plant Compliance Coordinator requesting him to forward compliance related requests to the CATS administrator for tracking in CATS. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019021228	PRC-005-6	R3	FirstEnergy Generation and Marketing as agent for etc.	NCR11317	1/1/2018	3/14/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On March 6, 2019, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-005-6 R3. The entity did not perform required 6-year protective relay maintenance testing specified in PRC-005-6 on three different microprocessor relays. All three microprocessor relays were installed in 2011 and required maintenance by the end of 2017. All three microprocessor relays were located at Bruce Mansfield Unit 3. One microprocessor relay was installed on April 13, 2011, and the other two microprocessor relays were installed on April 14, 2011. The entity discovered this issue during an internal audit of PRC-005-6 R3. The root cause of this noncompliance was a lack of effective internal controls around testing. The three microprocessor relays impacted were excluded from testing in a 2014 planned outage scope due to their recent installation. The next planned outage for Bruce Mansfield Unit 3 was in 2017, but that outage was delayed until 2018. Delaying the scheduled outage until 2018 resulted in the three microprocessor relays not being tested within six calendar years as required by PRC-005-6 R3. (The entity was finally able to get an outage in 2019 to perform the overdue maintenance and testing.) This noncompliance involves the management practices of grid maintenance and work management. Grid maintenance management is involved because the entity failed to effectively perform the requisite maintenance scheduling to execute PRC-005-6 R3 compliance. Work management is involved because the entity failed to properly schedule long term projects in order to comply with PRC-005-6. This noncompliance started on January 1, 2018, when the entity failed to perform required 6 calendar year relay maintenance testing and ended on March 14, 2019, when the entity completed its required 6 calendar year relay maintenance testing. (Microprocessor relays are required to be tested on a six calendar year interval. For PRC-005-6, a calendar year starts on the first day of a new year (January 1) after the maintenance activity has been completed. In this case, the entity performed testing on the first microprocessor relay on April 13, 2011. That means the entity had six years from January 1, 2012 to test the microprocessor relays again. The start date of this noncompliance is therefore January 1, 2018.)
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk associated with failing to perform required maintenance activities within the required timeframe is that the device could fail to perform as expected, which could reduce the reliability of the BPS. The risk is minimized because the duration was limited; the 6-year relay maintenance testing was performed approximately one year late. Further minimizing the risk, only three microprocessor relays were not tested within the 6-year relay maintenance testing interval. The entity confirmed that all other protection system devices (28 in total) were timely tested at Bruce Mansfield Unit 3. Additionally, these microprocessor relays have relay failure alarms enabled which would inform the entity remotely of a relay failure via Supervisory Control and Data Acquisition. No harm is known to have occurred. The entity has relevant compliance history. However, ReliabilityFirst determined that the entity's compliance history should not serve as a basis for applying a penalty because the prior violation involved different facts and circumstances and while the result of the prior noncompliance was arguably similar, the prior noncompliance arose from a different cause.
Mitigation	To mitigate this noncompliance, the entity: 1) reviewed the Mansfield Plant NERC Protective Device List for accuracy and no additional relays were found outside of their maintenance interval; 2) made all efforts to test the three microprocessor relays within 90 days; 3) added the three relays to the plant's Forced Outage Work List, so they can be tested during the next outage of sufficient duration; and 4) included a preventative control in the planning process for Planned Outages, for an independent review of the entity's Plant NERC Protective Devices List to help prevent future occurrences.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019021229	MOD-025-2	R1	FirstEnergy Generation and Marketing as agent for etc.	NCR11317	7/1/2017	6/5/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On March 8, 2019, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R1. The FEGM fleet was below the required 60% implementation milestone for MOD-025-2 as of July 1, 2017 due to asset transfers. On April 20, 2017, the entity transferred thirteen (13) generating units to FirstEnergy Utilities (FEU). The result from the transfer between FEGM and FEU is that FEGM went from 63% complete to 42% complete; bringing it from compliant to non-compliant with MOD-025-2 R1. Therefore, FEGM fell short of the 60% implementation milestone on July 1, 2017. This noncompliance involves the management practices of work management and verification as the entity did not verify that its interpretation of MOD-025-2 R1 compliance requirements was correct. The root cause of this noncompliance was that the entity did not realize that current asset sales or asset transfers required a retroactive recalculation of phased implementation percentages. The entity was compliant with all phased implementation percentages on the actual phased implementation date as prescribed in the implementation plan. Subsequent sales of generating assets or asset transfers caused the percentages to drop below the phased implementation percentages as prescribed in the implementation plan. This noncompliance started on July 1, 2017, when the entity was required to comply with MOD-025-2 R1 and ended on June 5, 2018, when the entity completed additional testing to reach the 60% implementation milestone.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed is that by providing incorrect data or not providing data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because, although the entity was not compliant on the July 1, 2017 phased-in implementation date because of the asset transfer, the entity was compliant with the phased-in implementation percentages on July 1, 2016 and July 1, 2018. The entity's sale of generating assets/asset transfers caused the percentages to temporarily drop below the phased implementation percentage of 60% for the July 1, 2017 phased-in implementation date. The risk is further reduced because FirstEnergy's fleet of generators (including FEGM and FEU) did not fall below the July 1, 2017 60% implementation milestone. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) performed additional testing to bring the entity to 68% percent complete with the implementation plan for MOD-025-2; and 2) tested Sammis Unit 7 which completed the entity's implementation plan for MOD-025-2.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019020961	PRC-005-6	R3	Keystone Urban Renewal, LP	NCR00810	4/1/2017	10/18/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On January 10, 2019, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-005-6 R3. The entity installed a new battery bank of Vented Lead-Acid (VLA) batteries in May, 2015, but failed to establish a baseline. Thereafter, the entity failed to verify that the batteries could perform as manufactured by evaluating cell/unit measurements indicative of battery performance against a baseline. Such maintenance activities were required to be performed at least once every 18 calendar months pursuant to PRC-005-6 R3 – Table 1-4(a). The entity identified the issue during a review of maintenance records. The root cause of this noncompliance was inadequate controls relating to the development and implementation of maintenance activities. The entity developed and implemented a number of maintenance activities relating to the batteries but overlooked the need to establish a baseline and test for battery performance at least once every 18 calendar months. This noncompliance involves the management practices of implementation and verification. The entity implemented the new battery bank in 2015, and it should have ensured that sufficient maintenance requirements were also communicated and implemented. And, successful implementation can be determined through verification, which can help an entity ensure that the Bulk Electric System continues to be updated, operated, and maintained correctly. This noncompliance started on April 1, 2017, when the entity failed to comply with all of the maintenance and testing requirements set forth in PRC-005-6 R3 and ended on October 18, 2018, when required maintenance and testing was completed.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System based on the following factors. Station batteries are an important part of the station direct current (dc) supply and may be called upon to provide instantaneous dc power to operate circuit breakers or interrupting devices to clear faults or to isolate equipment. Neglecting to inspect and test station batteries could lead to a situation where the batteries cannot deliver dc power when required, potentially resulting in significant consequences relating to equipment damage and power system performance. The risk was mitigated by the following factors. First, the batteries were brand new as of May, 2015, and, therefore, were less likely to have been experiencing performance issues at the time of this noncompliance. Second, the entity had been conducting daily battery and battery charger visual inspections and quarterly data collection and maintenance inspections, which increased the likelihood that any performance issues would have been promptly discovered during the period of this violation. The quarterly data collection and maintenance inspection activities included: (a) verifying float voltage and amps of the battery chargers; (b) inspecting the physical condition of the batteries, battery support racks, mountings, anchorage and groundings, and connections; (c) inspecting electrolyte levels, individual cell voltage, and temperature corrected specific gravity readings; and (d) monitoring specific alarms. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) performed required maintenance/testing and established a baseline to verify future readings; and 2) created a preventive maintenance task to specifically address the 18-month maintenance criteria as prescribed in Table 1-4(a).

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019021053	EOP-005-2	R17	Lake Lynn Generation, LLC	NCR11447	2/13/2014	8/31/2019	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On February 5, 2019, ReliabilityFirst determined that the entity, as a Generator Operator, was in noncompliance with EOP-005-2 R17 identified during a Compliance Audit conducted on January 25, 2019. During the audit, the entity was unable to provide sufficient evidence that it provided a minimum of two hours of training on its Blackstart Resource startup procedure for all applicable personnel. Specifically, for the years 2014-2018, the entity provided excel spreadsheet rosters that included only the year, names, and roles. ReliabilityFirst could not determine when the training was actually provided, if all of the people on the list actually attended the training, and whether all applicable personnel were identified. The root cause of this noncompliance was the entity's lack of awareness of the detail required in the documentation for this training. This root cause involves the management practice of workforce management, which includes providing training, education, and awareness to employees. This noncompliance started on February 13, 2014, when the entity registered as a Generator Operator and ended on August 31, 2019, when the entity completed its Mitigating Activities.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by failing to properly train applicable personnel on the system restoration plan is that applicable personnel may not be able to execute the plan efficiently and effectively. This risk was mitigated in this case by the following factors. First, while the entity did not sufficiently document who attended the training, it did provide sufficient evidence demonstrating the content of the training. Second, the entity provided completed Blackstart Resource test forms, indicating that it had, in fact, been running the test procedure. These factors support the conclusion that this issue was primarily a documentation issue. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) enhanced its documentation so that adequate evidence of training will be available in the future; and 2) ensured all applicable personnel received the training.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020794	VAR-002-4.1	R2	LSP University Park, LLC	NCR11107	1/24/2018	12/31/2018	Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 3, 2018, ReliabilityFirst determined that the entity, as a Generator Operator, was in noncompliance with VAR-002-4.1 R2 identified during a Compliance Audit conducted from December 3, 2018 through December 14, 2018. During the audit, ReliabilityFirst requested evidence that the entity maintained the generator voltage or Reactive Power schedule provided by the Transmission Operator (TOP), or otherwise met the conditions of notification for deviations from the voltage or Reactive Power schedule. For three of the requested samples, the entity could not provide any evidence of compliance because, during those time periods, the entity did not have the capability to maintain historical data or evidence. Multiple other data samples demonstrated that the entity failed to maintain the generator voltage or Reactive Power schedule provided by the TOP, or otherwise meet the conditions of notification for deviations from the voltage or Reactive Power schedule. (The largest deviation the entity experienced was .8% below schedule (i.e., 3 kV below). However, most of the deviations were .1-.3% below schedule (i.e., .5 to 1 kV below).) The root cause of this noncompliance was the entity’s inability to store historical data and the lack of preventative and detective controls. This root cause involves the management practices of information management, in that the entity failed to maintain important information, and reliability quality management, which includes maintaining a system for deploying internal controls. This noncompliance started on January 24, 2018, the start date of the first data sample for which the entity failed to provide evidence of compliance and ended on December 31, 2018, when the entity implemented system alarms and corrected the data retention issue.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by this noncompliance is a negative impact on the reliable operation of the BPS by allowing detrimental levels of generator voltage or reactive power output. This risk was mitigated by the following factors. First, the plant’s Transmission Owner and TOP were aware of the plant’s voltage at all times and did not contact the plant to have it take any action. Second, the deviations were small, mostly .1-.3% below schedule, with the largest deviation being only .8% below schedule. No harm is known to have occurred. ReliabilityFirst considered the entity’s compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) added control system alarms to alert operators when the voltage schedule is being exceeded; 2) added historical voltage data tags to the entity’s database; 3) provided training for all operating personnel on the VAR-002 Standard, including plant-specific information for Requirement 2, and how the plant should respond to events where the plant cannot meet the requirements of its voltage schedule; and 4) updated its night orders to include voltage schedule information and voltage schedule reporting requirements.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019020909	EOP-004-2	R3	Washington City Light & Power	NCR00941	1/1/2016	12/31/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 31, 2018, the entity submitted a Self-Report stating that, as a Distribution Provider, it was in noncompliance with EOP-004-2 R3. As background, the entity has historically worked with IMPA Service Corporation (ISC) to assist it with its NERC compliance. ISC had one employee devoted to this role. When that person left ISC, a new person took over and performed a full review of the entity's NERC compliance program. That review identified this issue. On January 1, 2014, the entity implemented its Event Reporting Operating Plan as required by EOP-004-2 R1. However, for the subsequent 3 years, the entity failed to validate all of the contact information in the plan. The root cause of this noncompliance was the entity's lack of internal controls to ensure it performed the annual review. The root cause involves the management practice of reliability quality management, which includes maintaining a system for deploying internal controls. This noncompliance started on January 1, 2016, when the entity was required to complete its first validation of the contact information and ended on December 31, 2018, when the entity actually validated the contact information.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The potential risk associated with failing to annually validate the contact information in the Operating Plan is that notification to these parties could be delayed due to outdated or inaccurate information. This risk was mitigated in this case by the following factors. First, the contact information in the Operating Plan generally does not change often, and in this case, it did not change. Second, despite the fact that the contact information was not annually updated, the contact information is generally known to entity personnel, such as the emergency contact for local law enforcement (i.e., 911). Third, the entity's peak load is only 40 MW with two interconnections to the Bulk Electric System at 138 kV. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance
Mitigation	To mitigate this noncompliance, the entity validated the contact information in the entity's Event Report Operating Plan.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021330	PRC-005-6	R3	CER Generation LLC (CER)	NCR10390	07/01/2017	12/06/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On April 9, 2019, CER submitted a Self-Report stating that, as a Generation Owner, it was in noncompliance with PRC-005-6 R3. SERC determined that CER failed to maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within PRC-005-6's Table 1-4. On September 28, 2018, CER began a compliance review of its battery maintenance procedures and methods of acceptable evidence. This review was in response to feedback received by an affiliate based on a recent audit. On July 1, 2017, the Albany Green Energy (AGE) facility completed commissioning. Beginning at commissioning through the discovery date, the documentation was insufficient to show compliance with the Standard for all batteries at the facility. Specifically, the documentation was insufficient for (i) verification of the float voltage of the battery charger (18 month maximum interval), (ii) inspection of the electrolyte levels (4 month maximum interval), (iii) inspection for Unintentional Grounds (4 month maximum interval), and (iv) inspection of the physical condition of battery rack (18 month maximum interval). CER contends that during this time, contractors performed battery maintenance in accordance with PRC-005-6, but that the contractors used their own templates. CER stated that the contractor templates did not have an affirmative check off for the noncompliant items. For instance, the template only required documentation of a "failure" of physical condition, but not of a "passed" physical condition. CER does have documentation for the other requirements of PRC-005-6 Table 1-4. The noncompliance was limited to the single bank of batteries at the AGE facility which accounts for roughly 20% of batteries owned by CER. CER has two facilities, the AGE facility, which has a single battery bank, and one other facility, which has four battery banks. CER reviewed documentation and maintenance scheduled at both facilities and determined that only the AGE facility was lacking sufficient documentation. The AGE facility is a biomass generator with a nameplate rating of 64 MVA. This noncompliance started on July 1, 2017, when CER registered the AGE facility with insufficient documentation, and ended on December 6, 2018, when CER completed sufficient documentation of its testing results. The root cause of this noncompliance was ineffective vendor management. CER allowed the contractor to use their own form and accepted it as a compliance evidence, regardless of its incomplete data.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The lack of battery maintenance at the AGE facility could have led to improper tripping or equipment damage. While the length of noncompliance is significant, the batteries were new which lessened the chance of maintenance related issues and records show some portions of battery maintenance were completed and that at 64 MVA, the risk of a trip of the facility or long term outage would be minimal to the BPS. No harm is known to have occurred. SERC considered CER's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, CER: 1) documented all maintenance and testing appropriately; 2) combined compliance procedures for clarity; 3) set documentation expectations (CER's form instead of vendors' form) with contractors; 4) set schedule to review documentation quarterly; 5) set schedule to conduct quarterly maintenance review of documentation; and 6) provided training of the procedure revision to the maintenance manager.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017017987	PRC-024-2	R2	Duke Energy Carolinas, LLC (DEC)	NCR01219	07/01/2016	03/29/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 21, 2017, Duke Energy Carolinas, LLC (Duke) submitted a Self-Report stating that, as Generator Owner, it was in noncompliance with PRC-024-2 R2. DEC reported that it did not verify that 40 percent of its generating units met the required setpoints, in accordance with the NERC Implementation Plan. Also on that date, Duke Energy Progress, LLC (DEP), Duke Energy Florida, LLC (DEF), and Duke Energy Corporation (DECorp) submitted Self-Reports, with tracking numbers SERC2017017996, SERC2017017997, and SERC2017017992, respectively, making the same assertion. DEC, DEP, DEF, and DECorp are subject to a multi-regional registered entity (MRRE) agreement and, as such, SERC rolled the Self-Reports for DEP, DEF, and DECorp into the instant Self-Report. Hereafter, this document refers to all four affiliates, collectively, as the Entities. Prior to July 1, 2016, the Corporate Compliance Group, who represented the Entities, developed a plan of action to meet the NERC Implementation Plan of PRC-024-2 R2. In accordance with the Corporate Compliance Group's plan, each Entity believed that it had completed all of the verification of devices required to meet the implementation milestone of 40 percent of its applicable facilities. However, the Corporate Compliance Group interpreted the requirement to exclude generator trips associated with the generator excitation systems. Therefore, the Entities failed to verify the generator trips associated with the generator excitation systems, which is a necessary and needed component of compliance of PRC-024-2 R2. The Entities all had 0 percent compliance with PRC-024-2 R2 on July 1, 2016. On December 14, 2016, NERC discussed the scope of PRC-005-6 and published its interpretation that NERC's definition of Protection Systems included generator trips associated with generator excitation systems. On March 29, 2017, the Entities completed testing to bring the Entities back into compliance with the NERC Implementation Plan. This testing came as a direct result of the aforementioned NERC meeting. No setting changes were required due to the testing. This noncompliance started on July 1, 2016, when the Entities should have verified the setpoints of at least 40 percent of its generators, and ended on March 29, 2017, when Duke completed verification of the generator trips associated with the generator excitation systems. The root cause of this noncompliance was a misinterpretation of the requirements of PRC-024-2. Specifically, the Entities failed to identify that the Requirement included generator trips associated with the generator excitation systems.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The Entities' failure to properly verify the frequency protection setpoints could result in generators unnecessarily tripping off-line during frequency transients. Outside of the generator excitation systems, all testing was completed within the appropriate timeframe. The Entities operated during the period of noncompliance with no trips due to incorrect setpoints. No harm is known to have occurred. SERC considered compliance history of the Entities and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the Entities: 1) performed an evaluation of protective functions in excitation systems with applicability in Protection Systems; 2) pulled PRC-024 documentation used to achieve 40 percent milestone on 7/1/2016 for reevaluation and modified PRC-024 review scope and program philosophy to require studies to incorporate protective functions in the excitation system, which required revision of existing studies and new studies to include the voltage and frequency protective functions in the excitation systems. 3) added excitation Protection System functions to applicable coordination studies and Duke Energy Fossil-Hydro and Nuclear Generation met the 60 percent milestone in all regions by 7/1/2017. 4) implemented a compliance program checkpoint/Quality Assurance review to: (i) evaluate new processes and programs prior to implementation, (ii) evaluate the program against the Requirements and Measures of the NERC Reliability Standard, (iii) document any program bases and incorporated interpretations, and (iv)) poll other utilities for common interpretation when there is no internal consensus. If affiliates cannot reach consensus, the Quality Assurance Process document will require the Entities to utilize established processes to request interpretation from NERC when necessary.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017018417	PRC-005-1.1b	R2	Duke Energy Progress, LLC (DEP)	NCR01298	08/01/2015	11/16/2016	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 29, 2017, Duke Energy Progress, LLC (DEP), under an existing multi-region registered entity agreement, submitted a Self-Report on behalf of Duke Energy Florida, LLC (DEF) stating that, as a Transmission Owner (TO), DEF was in noncompliance with PRC-005-6 R3. DEF had not performed required maintenance for one battery in accordance with its Protection System Maintenance Program (PSMP). On July 24, 2014, DEF installed and commissioned a new battery in a new control house at Drifton 115kV/69 kV substation. On November 15, 2016, a DEF Inspector contacted the Construction and Maintenance Compliance Analyst (Analyst) because the DEF Inspector believed that the battery had not been tested since its installation. DEF determined that it failed to submit an Equipment Change Request (ECR) after the installation of the battery; therefore, the battery was not included in the maintenance database or the maintenance and testing schedule. As a result, DEF did not perform any of the required 4-calendar month activities or the 18-calendar month maintenance and testing requirements it should have performed in January 2016. Additionally, DEF did not test the trouble alarms associated with the battery for proper operation. This noncompliance started on August 1, 2015, when DEF failed to perform the required battery maintenance, and ended on November 16, 2016, when DEF performed the required battery maintenance. The root cause of this noncompliance was a lack of training. An ECR was required to be completed after the installation of the battery and DEF failed to complete and submit the ECR.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Failure to perform periodic battery maintenance could prevent the battery from performing its design function to trip protective devices to clear faults on the transmission system. However, this noncompliance affected a single battery at a noncritical 115 kV/69 kV substation. Additionally, the battery was new; therefore, immediate failure was unlikely. DEF performed periodic substation inspections that included the Direct Current systems. The noncompliance did not cause incorrect operation or prevent normal operation at the Drifton substation. When DEF tested the battery, the results indicated that the battery could have performed its design function. No harm is known to have occurred. SERC determined that DEF's compliance history should not serve as a basis for applying a penalty. Although DEF has compliance history with PRC-005, the prior noncompliance involved 2013 and 2015 instances covering different standard versions, and the underlying conduct between these prior instances was different. DEF's compliance history does not demonstrate a programmatic failure. SERC reviewed the posted violations for PRC-005 for affiliates of DEF, DEP, Duke Energy Carolinas, LLC, and Duke Energy Corporation and did not identify circumstances similar to that of the instant issue. Each Duke affiliate is responsible for its own maintenance and testing program and the completed mitigation plans would not have addressed the instant issue. Therefore, SERC did not consider violation history of DEF's affiliates as aggravating circumstances.
Mitigation	To mitigate this noncompliance, DEF: 1) performed required substation maintenance on the Battery Bank; 2) reviewed and submitted the completed ECR to the Cascade database; 3) communicated to Construction, Maintenance, and Vegetation (CMV) in DEF and DEP, their responsibility to complete ECR's for all units of property within 14 days following completion of equipment commissioning tests. For CMV in the DECorp and DEC, management communicated their current equipment change process and expectations to their respective teams; 4) reviewed, with the project team, the ECR process that shows the steps to have ECRs submitted so that equipment changes are updated in the Asset Management System and maintenance triggers/intervals are set up for all Project, or Emergent Capital Project activities; 5) performed a battery inventory at all 100kV and above Bulk Electric System (BES) locations to ensure all are represented in the regions asset systems and have the correct battery type; and 6) conducted training by communicating investigation findings, lessons learned, and process changes across all four Entity Regions.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
FRCC2019021740	MOD-026-1	R2	Hardee Power Partners Limited (HPS)	NCR00035	07/01/2018	11/20/2018	Self-Report	Complete

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 26, 2019, HPS submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-026-1 R2. HPS did not provide its Transmission Planner (TP) a verified generator excitation control system or plant volt/var control function model in accordance with the NERC Implementation Plan. The Hardee Power Station consists of one block of a 2-on-1 combined-cycle power plant (CT1A, CT1B & ST1) and two simple-cycle gas turbine-generators (CT2A & CT2B). The units’ facility ratings are: CT1A – 112.8 MVA, CT1B – 112.8 MVA, ST1 – 112.8 MVA, CT2A – 112.8 MVA, and CT2B – 101.8 MVA. HPS was on track to complete its MOD-026 R2 30% compliance by the required due date; however, when HPS reached out to the testing contractors with a five month lead time, the contractors were not available (due to high demand) to perform the test and provide a final report along with the required models by the July 1, 2018 deadline. On June 13, 2018, the contractors were on site to perform the testing. However, on June 7, 2018, HPS GSU1 had an internal fault, which caused units CT1A, CT1B, and ST1 to be unavailable for testing. The contractors could not complete the testing on these units until the replacement of GSU1. Therefore, HPS conducted testing in two phases June 13, 2018 and July 18, 2018. On June 13, 2018 CT2B was tested and on July 18, 2018 CT1A, CT1B, and ST1 were tested. Due to the failure and subsequent outage of GSU2, CT2A is the only unit remaining to be tested. Although CT2A remains to be tested, per the implementation plan, 80% of the site generation testing and TP submission are complete. HPS failed to meet the 30% (166 MVA) Implementation Plan requirement on the available units prior to July 1, 2018, and was unable to submit a verified generator excitation control system or plant volt/var control function model for each applicable unit to its TP on or before July 1, 2018. On November 20, 2018, HPS, submitted the required report and model to its TP, satisfying the R2 Implementation Plan for July 1, 2018 and July 1, 2020. This noncompliance started on July 1, 2018, when HPS was required to meet the 30% Implementation Plan, and ended on November 20, 2018, when HPS submitted the model data to its TP and met the 30% Implementation Plan requirement. The primary cause of the delayed submission was inadequate planning on behalf of HPS management. There was limited availability of qualified contractors to perform the testing on or before July 1, 2018 despite providing a five month lead time.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. HPS failure to provide its TP verified model data for HPS generating units could result in inaccurate system models. However, HPS provided the data for the generating units only 142 days late for a requirement that has a full implementation requirement of July 1, 2024. Due to the new GSU being exactly the same as the failed GSU, the models, ratings, and impedances did not have a major impact to the previously provided information, which the TP had on file. The TP was able to utilize previously submitted data for modeling purposes. HPS has a capacity factor of 20.48%. No harm is known to have occurred. SERC considered HPS’s compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, HPS: 1) submitted the model to its TP; 2) created an excel document to monitor all due dates stored on its Compliance SharePoint site; and 3) implemented a process to identify and track compliance deadlines that require the services of a third-party vendor, including a control to estimate lead times and send automated reminders.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
FRCC2019021741	MOD-027-1	R2	Hardee Power Partners Limited (HPS)	NCR00035	07/01/2018	11/20/2018	Self-Report	Complete

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 26, 2019, HPS submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-027-1 R2. HPS did not provide its Transmission Planner (TP) a verified turbine/governor and load control or active power/frequency control model in accordance with the NERC Implementation Plan. The Hardee Power Station consists of one block of a 2-on-1 combined-cycle power plant (CT1A, CT1B & ST1) and two simple-cycle gas turbine-generators (CT2A & CT2B). The units' facility ratings are: CT1A – 112.8 MVA, CT1B – 112.8 MVA, ST1 – 112.8 MVA, CT2A – 112.8 MVA, and CT2B – 101.8 MVA. HPS was on track to complete its MOD-027 R2 30% compliance by the required due date; however, when HPS reached out to the testing contractors with a five month lead time, the contractors were not available (due to high demand) to perform the test and provide a final report along with the required models by the July 1, 2018 deadline. On June 13, 2018, the contractors were on site to perform the testing. However, on June 7, 2018, HPS GSU1 had an internal fault, which caused units CT1A, CT1B, and ST1 to be unavailable for testing. The contractors could not complete the testing on these units until the replacement of GSU1. Therefore, HPS conducted testing in two phases June 13, 2018 and July 18, 2018. On June 13, 2018 CT2B was tested and on July 18, 2018 CT1A, CT1B, and ST1 were tested. Due to the failure and subsequent outage of GSU2, CT2A is the only unit remaining to be tested. Although CT2A remains to be tested, per the implementation plan, 80% of the site generation testing and TP submission are complete. HPS failed to meet the 30% (166 MVA) Implementation Plan requirement on the available units prior to July 1, 2018, and was unable to submit a verified turbine/governor and load control or active power/frequency control model for each applicable unit to its TP on or before July 1, 2018. On November 20, 2018, HPS, submitted the required report and model to its TP, satisfying the R2 Implementation Plan for July 1, 2018 and July 1, 2020. This noncompliance started on July 1, 2018, when HPS was required to meet the 30% implementation plan, and ended on November 20, 2018, when HPS submitted the model data to its TP and met the 30% implementation plan requirement. The primary cause of the delayed submission was inadequate planning on behalf of HPS management. There was limited availability of qualified contractors to perform the testing on or before July 1, 2018 despite providing a five month lead time.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. HPS failure to provide its TP verified model data for HPS generating units could result in inaccurate system models. However, HPS provided the data for the generating units only 142 days late for a requirement that has a full implementation requirement of July 1, 2024. Due to the new GSU being exactly the same as the failed GSU, the models, ratings, and impedances did not have a major impact to the previously provided information, which the TP had on file. The TP was able to utilize previously submitted data for modeling purposes. HPS has a capacity factor of 20.48%. No harm is known to have occurred. SERC considered Hardee Power Partners (HPS) compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, HPS: 1) submitted the model to its TP; 2) created an excel document to monitor all due dates stored on its Compliance SharePoint site; and 3) implemented a process to identify and track compliance deadlines that require the services of a third-party vendor, including a control to estimate lead times and send automated reminders.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
FRCC2019021742	MOD-032-1	R2	Hardee Power Partners Limited (HPS)	NCR00035	07/01/2016	07/14/2017	Self-Report	Complete
Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 26, 2019, HPS submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-032-1 R2. HPS failed to provide accurate steady-state, dynamics, and short circuit modeling data to its Planning Coordinator (PC) according to the data requirements and reporting procedures developed by its PC and Transmission Planner (TP) in Requirement R1. On December 15, 2016, while reviewing the general performance completion records, HPS discovered it failed to provide steady-state, dynamics, and short circuit modeling data to its TP and PC on or before July 1, 2016. On July 14, 2017, HPS, made its notification to its TP and PC notifying them of no data changes, satisfying R2. This noncompliance started on July 1, 2016, when HPS was required to provide steady-state, dynamics, and short circuit modeling data to its TP and PC, and ended on July 14, 2017, when HPS submitted the model data to its TP and PC. The primary cause of this noncompliance was a lack of internal controls related to administrative scheduling oversight and limited resources.							
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. HPS's failure to provide its TP and PC verified steady-state, dynamics, and short circuit modeling data could result in inaccurate system models. However, HPS had no changes to its model during the violation period since its last submission, which was in 2012 and 2013. The delayed receipt of such plant data presented no variation in planning results. Additionally, HPS's geographical location within the Region and relatively small size (553 MVA) would have minimal impact. No harm is known to have occurred. SERC considered HPS's compliance history and determined that there were no relevant instances of noncompliance.							
Mitigation	To mitigate this noncompliance, HPS: 1) submitted the model data to its TP and PC; 2) created an automated task notification in its internal task management system to send automated email reminders to the responsible Subject Matter Experts (SMEs) 60 days prior to each targeted 12-month review period; additionally, the task escalates to the compliance team if not completed within 30 days of the due date; 3) reviewed the model guidelines and discussed the annual future model update expectations with the applicable compliance team, which was followed by a discussion with the responsible SME s about the importance of planning to ensure performance deadlines are met; 4) hired two additional compliance personnel to better manage and monitor performance action dates, addressing the administrative oversight issue; and 5) updated the task to confirm the NERC calendar is regularly reviewed with all upcoming due dates.							

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018020187	PRC-024-2	R2	Holland Energy, LLC (Holland)	NCR01255	07/01/2016	06/21/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On August 3, 2018, Holland submitted a Self-Report to SERC stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R2. Holland did not set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating units as a result of a voltage excursion within the "no trip zone" of PRC-024 Attachment 1 in accordance with the NERC implementation plan. On July 1, 2016, Holland was required to be 40% compliant with PRC-024 R2, and on July 1, 2017, 60% compliant. Holland owns two combustion turbines (CTs) and one steam turbine (ST), with a plant capacity factor of 15.8%. On June 21, 2016, contractor A, providing compliance and operations support for Holland's generators, completed an evaluation report for PRC-024-2 R2 and incorrectly determined that all voltage relays were compliant with the Standard and Requirement. Contractor A determined that six relays on Holland's three units were found to be applicable to PRC-024-2 having both over and underfrequency protection with the exception of one Digital Generator Protection Relay (DGP) relay on CTG 2, which was set to only underfrequency. Contractor A also determined that the voltage relaying for all three units were compliant. Later in June 2016, Holland hired contractor B to provide a Coordination Study for a different NERC Reliability Standard and Requirement. The study determined that the Frequency Relays were set correctly. However, it was determined the DGP generator protective relay element was set incorrectly for under-voltage ride through, for both CT1 and CT2. In February 2018, Holland received a draft report, which included contractor B's results of PRC-024. On May 18, 2018, Holland received the final report with the recommendation to change the DGP under-voltage curve element from 1 (inverse time) to 2 (definite time) for CT1 and CT2 only, so that the trip element was outside the "no trip zone" for voltage ride-through. Holland noted that contractor A verified that the ST settings were correct. Because Holland only had the ST settings correct on July 1, 2016 and July 1, 2017, it was only 33% compliant with the PRC-024 implementation plan. On June 21, 2018, Holland again hired contractor B to perform all setting changes to its generator protective relays from the final report of May 18, 2018, changing the Time Curve elements on CT1 and CT2 from 1 (inverse time) to 2 (definite time). This noncompliance started on July 1, 2016, when PRC-024-2 became effective, and ended on June 21, 2018, when Holland corrected the relay settings for 100% of the applicable relays. The root cause of this noncompliance was a failure to have internal controls in place for oversight of contractors to ensure a verification process for all evaluation reports performed by all third-party contractors.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The protective relays set within the "no trip zone" could have led to incorrect tripping of Holland's units. However, the individual output of each CT (189 MWs) is a minimal impact to the SERC region. Additionally, the plant capacity factor is only 15.8%, having little impact to the BPS. The Holland Facility did not have any unit trips based on under-voltage relay settings during the period of noncompliance. No harm is known to have occurred. SERC considered Holland's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Holland: 1) completed all relay setting changes; 2) completed an internal NERC audit by independent operations contractor personnel audit summary document prepared and Compliance Log updated; 3) completed all contractor reports in draft format for review by Subject Matter Experts (SMEs); 4) signed off for review and acceptance of reports by SMEs; and 5) updated Holland Energy, LLC NERC Compliance Manual to include a documentation verification process of evaluation reports subject to PRC and MOD Standards; this review included SMEs.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021091	PRC-024-2	R1	Innovative Solar 42, LLC (InnSol42)	NCR11782	09/08/2017	Present	Self-Report	12/31/2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On February 25, 2019, InnSol42 submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with PRC-024-2 R1. InnSol42, as a GO with generator frequency protective relaying activated to trip its applicable generating units, failed to set its protective relaying, such that, the generator frequency protective relaying did not trip the applicable generating units within the "no trip zone", as described in PRC-024-2 Attachment 1, in accordance with the NERC Implementation Plan. InnSol42 has a total of 35 inverters of type one, each at 2.2 MVA, and one inverter of type two, at 1.1 MVA, that all have a single interconnection point to the Bulk Electric System. The solar photovoltaic (PV) inverters (type two) were improperly set during commissioning, meaning that InnSol42 had a 0% completion for the July 1, 2016, July 1, 2017, and July 1, 2018 deadlines in the Implementation Plan. The total capacity affected by this noncompliance was 78.1 MVA, and capacity factor for the affected generation was 20.90%. On April 13, 2017 and April 25, 2017, InnSol42 and the inverter manufacturer agreed upon the inverter settings prior to commissioning, which if implemented, would have been compliant with PRC-024-2 R1. However, the inverter manufacturer did not implement the agreed upon settings. On September 8, 2017, InnSol42 registered as a GO. Additionally, on this date a technician took screenshots of the monitoring software that showed individual inverter voltage and frequency ride-through settings. The software used to produce the screenshots was missing a proprietary component, which introduced errors into the data. These errors made the screenshots appear to show compliance but the inverters were actually not in compliance. On or about November 20, 2018, the InnSol42's Transmission Operator sent a request to review the May 1, 2018 NERC Alert II. In preparation for the review meeting, InnSol42 contacted its Operation & Maintenance (O&M) Provider and requested a spot check of the inverters. Discrepancies between the spot check and the screenshots taken on September 8, 2017 were discovered. On February 1, 2019, InnSol42 and the O&M Provider met to review the settings. It was determined that a potential noncompliance existed, as three frequency settings per inverter did not meet the PRC-024-2 R1 Requirements, specifically, the: (i) 60.5 Hz setting of 600 seconds with a requirement of 600.669 seconds; (ii) 59.5 Hz setting at 1792 seconds with a requirement of 1792.05 seconds; and (iii) 58.7 Hz settings at 73 seconds with a requirement of 73.0315 seconds. After additional review, InnSol42 determined that all inverters were in noncompliance. InnSol42 also discovered that the proprietary software referenced above was missing, which introduced errors in monitoring software. This noncompliance started on September 8, 2017, when InnSol42 registered with improper inverter settings, and will end on December 31, 2019, the date InnSol42 committed to completing its mitigation. The root cause of this noncompliance was ineffective contractor oversight. The inverter manufacturer failed to implement the agreed-upon settings, but InnSol42's internal controls failed to catch the error due improper software installation and a lack of verification of contractor work.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. InnSol42's failure to verify that the frequency protection relay settings properly coordinated could lead to a generator tripping for a system event that should not have caused the generator to trip. However, InnSol42's total output was 78.1 MVA and the maximum error was less than 0.7 seconds at the 600 second delay. In addition, the units did not trip during the period of noncompliance. No harm is known to have occurred. SERC considered InnSol42's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, InnSol42 will complete the following mitigation activities by December 31, 2019: 1) obtain Transmission Operator approval of inverter settings; 2) implement the approved settings; 3) develop a vendor and contractor inverter and protective relay change PRC-024 settings procedure that will be utilized for all future setting changes governed by NERC Reliability Standards; and 4) supply, by the inverter vendor/contractor, screen captures for all setting for each inverter, upon implementation of settings to inverters, regardless of whether all inverters required settings changes.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021709	MOD-032-1	R2	Summit Farms Solar, LLC (SummitSol)	NCR11834	06/16/2018	06/14/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 17, 2019, SummitSol submitted a Self-Report stating that, as a Generator Owner (GO) it was in noncompliance with MOD-032-1 R2. SummitSol failed to submit a steady-state, dynamics, and short circuit modeling data to its Transmission Planner (TP) and Planning Coordinator (PC) during the open submittal period from April 2, 2018, to June 15, 2018. On March 10, 2017, SummitSol began commercial operations of its 60 MW solar facility, with a Net Capacity Factor of 22.9%. In 2018 the parent company of SummitSol was required to submit or verify model data for 35 facilities within its footprint including SummitSol. Prior to the fourth quarter of 2018, the Power Generation Regulatory Compliance (PGRC) Lead was responsible for creating and owning a tracking tool to ensure compliance deliverables. The PGRC Lead submitted models for 34 of the 35 facilities, but failed to submit the model for SummitSol. On March 13, 2017, the developer/construction project manager sent the TP/PC the Generator As-Is study Unit Capability Data required for new construction generators to the TP/PC. On March 20, 2019, the SummitSol PGRC Lead was reviewing the 2018 modeling information in preparation for the 2019 submission of data and discovered that the 2018 data was not submitted to its TP/PC for the open period defined by the TP/PC of April 2, 2018, to June 15, 2018. This noncompliance started on June 16, 2018, when the open submittal period to the TP and PC closed and ended on June 14, 2019, when SummitSol submitted the steady state, dynamics, and short circuit modeling data to its TP and PC. The cause of this noncompliance was a lack of an internal controls, e.g., a secondary review prior to submittal, of MOD-032 data.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). SummitSol's failure to submit steady-state, dynamics, and short circuit modeling data to its TP and PC may have caused incorrect models within the RC topology. However, due to SummitSol small size the likelihood of harm is minimal because of the limited impact it would have to the BPS. No harm is known to have occurred. SERC considered SummitSol's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, SummitSol: 1) submitted steady-state, dynamics, and short circuit modeling data to its TP and PC; 2) implemented a secondary reviewer and a tracking software to assign, notify, and track the progress of MOD-032 for verification and submittal; 3) modified the MOD-032 Administrative Document to clarify PGRC Lead responsibilities; and 4) performed one-on-one training sessions with PGRC Leads to ensure expectations are understood by reviewing over-arching program and standard-specific documents.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017017739	PRC-024-2	R3	EDP Renewables North America, LLC (EDPR)	NCR11662	07/01/2016	06/29/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 14, 2017, EDPR submitted a Self-Report through an existing multi-region registered entity agreement stating that, as a Generator Owner (GO), it was in noncompliance with PRC-024-2 R3. Specifically, EDPR failed to document and communicate to its Planning Coordinator (PC) and Transmission Planner (TP) each known equipment limitation that prevented its generating units with generator frequency and voltage protective relays from meeting the relay setting criteria set forth in PRC-024-2, R1 and R2. During a subsequent Compliance Audit conducted September 11, 2017, through September 22, 2017, the audit team confirmed that several of EDPR's Facilities have Original Equipment Manufacturer (OEM) restrictions that present as "equipment limitations" as established in PRC-024-2 R1 and R2. It was further determined that these equipment limitations were not documented in accordance with PRC-024-2 R3, and were not communicated to the PC and TP within 30 days of identification, as is required by PRC-024-2 R3, paragraph 3.1. These instances of noncompliance occurred at four Facilities in the Western Electricity Coordinating Council (WECC) Region, two Facilities in the Texas Reliability Entity (Texas RE) Region, six Facilities in the Midwest Reliability Organization (MRO) Region, eight Facilities in the Reliability First (RF) Region, and one Facility in the Southeast Electric Reliability Corporation (SERC) Region. The root cause of this noncompliance was insufficient internal controls to ensure that EDPR identified and complied with all newly applicable NERC Reliability Standards. In particular, EDPR lacked adequate compliance procedures to ensure that the status of its frequency and voltage protective relays was determined so that associated equipment limitations could be documented and communicated to the PC and TP prior to the effective date of the Standard. This noncompliance started on July 1, 2016, when PRC-024-2 R3 became mandatory and enforceable, and ended on June 29, 2017, when EDPR provided the required notification of equipment limitations to its PC and TP in accordance with PRC-024-2 R3 for all of the applicable EDPR Facilities.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). EDPR failed to document and communicate each known equipment limitation affecting its Facilities. Such failure could result in inaccurate data modeling by the PC and TP when planning for system operating conditions and addressing contingencies. Inaccurate modeling could lead to an unexpected loss of the generation produced by EDPR Facilities. However, the average nameplate rating for the wind power plants within EDPR's fleet is 157 MW, and typical capacity factors are low. In the unlikely event that the OEM limitations identified as the basis for this noncompliance were to cause EDPR's Facilities to trip Off-Line, the affect would have been minimal due to the small number of MWs and capacity in question. No harm is known to have occurred. Texas RE considered EDPR's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, EDPR: 1) documented and communicated to its PC and TP each known equipment limitation that prevented its generating units from meeting the relay setting criteria set forth in PRC-024-2, R1 and R2; 2) implemented a procedure requiring the Director of Control Center and HV Operations to review and approve all summary sheets which document that the proper settings have been implemented and that proper documentation and notification has taken place; and 3) implemented a procedure that assigns specific EDPR staff responsibilities for monitoring revisions to the NERC Standards; requires quarterly meetings between key compliance staff; requires periodic monitoring of activities associated with compliance with NERC Standard Implementation Plans and deadlines; and mandates the collection and storage of compliance related evidence. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017017740	PRC-024-2	R1	EDP Renewables North America, LLC (EDPR)	NCR11662	07/01/2016	06/29/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 14, 2017, EDPR submitted a Self-Report through an existing multi-region registered entity agreement stating that, as a GO, it was in noncompliance with PRC-024-2 R1. Specifically, EDPR failed to set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating units within the "no trip zone" of PRC-024-2, Attachment 1. During a subsequent Compliance Audit conducted September 11, 2017, through September 22, 2017, the audit team reviewed EDPR's compliance with this Requirement and confirmed the noncompliance. This instance of noncompliance occurred in the Southeast Electric Reliability Corporation (SERC) Region. EDPR and its associated Registered Entities owned and operated 30 applicable wind generation Facilities in 2016, and 33 applicable wind generation Facilities in 2017. The Rail Splitter Wind Farm, LLC (Rail Splitter) is the only EDPR Facility in the SERC Region. In accordance with the Implementation Plan for PRC-024-2, Entities must have verified compliance for at least 40 percent of its applicable Facilities by July 1, 2016, and 60 percent of its applicable Facilities by July 1, 2017. During the audit EDPR's compliance percentages were calculated and it was determined that, as of July 1, 2016, EDPR was compliant with PRC-024-2 R1 in each Region in the following manner: • 100% compliant in the WECC Region • 100% compliant in the Texas RE Region • 40% compliant in the MRO Region • 70% compliant in the RF Region • 0% compliant in the SERC Region • 100% compliant in the NPCC Region June 26, 2017, through June 29, 2017, EDPR completed relay changes that brought its remaining Facilities into compliance with PRC-024-2 R1. The root cause of this noncompliance was insufficient internal controls to ensure that EDPR identified and complied with all newly applicable NERC Reliability Standards. In particular, EDPR lacked adequate compliance procedures to ensure that its voltage protective relays were set in accordance with PRC-024-2 prior to the Implementation Plan deadline for the Standard. This noncompliance started on July 1, 2016, when PRC-024-2 R1 became mandatory and enforceable, and ended on June 29, 2017, when EDPR completed the Required verifications.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The average nameplate rating for the wind power plants within EDPR's fleet is 157 MW. Additionally, there were no unit trips and no other misoperations at the applicable Facilities during the period of the noncompliance due to the identified equipment limitations. No harm is known to have occurred. Texas RE considered EDPR's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, EDPR: 1) completed relay changes that brought its remaining Facilities into compliance with PRC-024-2 R1; 2) implemented a procedure requiring the Director of Control Center and HV Operations to review and approve all summary sheets which document that the proper settings have been implemented and that proper documentation and notification has taken place; and 3) implemented a procedure that assigns specific EDPR staff responsibilities for monitoring revisions to the NERC Standards; requires quarterly meetings between key compliance staff; requires periodic monitoring of activities associated with compliance with NERC Standard Implementation Plans and deadlines; and mandates the collection and storage of compliance related evidence. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2019022272	PRC-019-2	R1	EDP Renewables North America (EDPR)	NCR11662	07/01/2016	06/29/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 14, 2017, EDPR submitted a Self-Report through an existing multi-region registered entity agreement stating that, as a GO, it was in noncompliance with PRC-019-2 R1. Specifically, EDPR did not verify the coordination of its voltage regulating system controls with the equipment capabilities and settings of applicable Protection System devices and functions by July 1, 2016 as required. During a subsequent Compliance Audit conducted September 11, 2017 through September 22, 2017, the noncompliance was confirmed. This noncompliance occurred at five Facilities in the Western Electricity Coordinating Council (WECC) Region, two Facilities in the Texas Reliability Entity (Texas RE) Region, ten Facilities in the Midwest Reliability Organization (MRO) Region, nine Facilities in the Reliability First (RF) Region, and one Facility in the Southeast Electric Reliability Corporation (SERC) Region. The two noncompliances of PRC-019-2 R1 by EDPR Facilities in the Northeast Power Coordinating Council (NPCC) Region have been addressed in TRE2017017737. The noncompliance was discovered during a PRC-019-2 compliance review conducted by EDPR in June of 2017. At the time of the noncompliance, EDPR and its associated Registered Entities owned and operated 30 applicable wind generation Facilities. During its review, EDPR discovered that various in-service Protection System devices were not set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits. According to EDPR, prior to the initial phased-in implementation of PRC-019-2 on July 1, 2016, EDPR's responsible parties worked to ensure EDPR's Registered Entities' voltage regulating system controls were coordinated with its applicable equipment capabilities and settings of the applicable Protection System devices prior to the initial compliance deadline. During the subsequent audit, it was determined that of the 30 EDPR Facilities, Timber Roads II was the only Facility for which EDPR provided evidence of verification and coordination as required by PRC-019-2 R1 by July 1, 2016. The root cause of this noncompliance was insufficient internal controls to ensure EDPR identified and complied with all newly applicable NERC Reliability Standards. In particular, EDPR lacked adequate compliance procedures to ensure that appropriate Entity personnel reviewed and verified summary sheets that document that proper coordination has taken place in accordance with PRC-019-2. This noncompliance started on July 1, 2016, when PRC-019-2 R1 became mandatory and enforceable, and ended on June 29, 2017, when EDPR completed voltage protection system settings verifications and upgrades in accordance with PRC-019-2 R1 at all of EDPR Facilities.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The average nameplate rating for the wind power plants within EDPR's fleet is 157 MW, and typical capacity factors are low. As such, had any of EDPR's Facilities been unnecessarily disconnected, the MW Capacity loss would have been small. No harm is known to have occurred. Texas RE considered EDPR's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, EDPR: 1) coordinated its voltage regulating system controls with the equipment capabilities and settings of applicable Protection System devices and functions; 2) implemented a review procedure requiring the Director of Control Center and HV Operations to review and verify summary sheets which document that proper coordination has taken place in accordance with PRC-019-2; and 3) implemented a procedure that assigns specific EDPR staff responsibilities for monitoring revisions to the NERC Standards; requires quarterly meetings between key compliance staff; requires periodic monitoring of activities associated with compliance with NERC Standard Implementation Plans and deadlines; and mandates the collection and storage of compliance related evidence. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018020856	MOD-026-1	R2	Kiowa Power Partners, LLC (KPP) (the "Entity")	NCR04088	07/01/2018	10/11/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 19, 2018, the Entity submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with MOD-026-1 R2. Specifically, the Entity failed to provide a verified generator excitation control system or plant volt/var control function model to its Transmission Planners (TPs) on or before July 1, 2018, as required by MOD-026-1 R2. The Entity's single generating Facility is switchable between the Texas Interconnection and the Eastern Interconnection, and the Entity is registered with both Texas RE and the Midwest Reliability Organization, Inc. (MRO). Accordingly, this issue affects both Regions. On October 9, 2018, during an annual internal compliance review, the Entity determined that it did not have evidence to demonstrate that it had provided the required verified modeling information for its single Facility to its TPs by July 1, 2018. On October 11, 2018, the Entity submitted the required verified modeling information to its TPs, ending the noncompliance. The root cause of this issue is that the Entity did not have a sufficient process for tracking and documenting compliance with MOD-026-1 R2. Specifically, the Entity stated that the employee responsible for submitting the required verified modeling information had previously indicated that this task had been timely completed, but, after that employee was no longer employed with KPP, the Entity was unable to obtain evidence from its internal records or from its TPs indicating whether or not that this task had been timely completed. This noncompliance started on July 1, 2018, when MOD-026-1 R2 became enforceable, and ended on October 11, 2018, when the Entity submitted the required model information to its TPs.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk posed by this issue is that the Entity's TPs would not have accurate modeling information when performing system planning. In addition, the Entity's Facility is a combined cycle generator comprising four combustion turbines and one steam turbine, with a total nameplate rating of 1,662 MVA. However, the risk posed by this issue was reduced by the following factors. First, although the Entity did not timely provide the required verified modeling information to its TPs, that information had already been documented by the Entity and could have been provided to the TPs immediately if it had been requested. Second, the duration of the noncompliance was short, lasting from July 2018 through October 2018. Finally, after providing the verified modeling information to its TPs, the Entity did not receive any notifications from its TPs that the verified modeling information was not usable for system planning. No harm is known to have occurred. Texas RE considered The Entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the Entity: 1) provided the required verified modeling information to its TPs; 2) implemented new compliance task management software, which is used to track activities for compliance with MOD-026-1; and 3) provided training to the Entity's compliance personnel regarding tracking report submissions.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018020857	MOD-027-1	R2	Kiowa Power Partners, LLC (KPP) (the "Entity")	NCR04088	07/01/2018	10/11/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 19, 2018, the Entity submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with MOD-027-1 R2. Specifically, the Entity failed to provide a verified turbine/governor and load control or active power/frequency control model to its Transmission Planners (TPs) on or before July 1, 2018, as required by MOD-027-1 R2. The Entity's single generating Facility is switchable between the Texas Interconnection and the Eastern Interconnection, and the Entity is registered with both Texas RE and the Midwest Reliability Organization, Inc. (MRO). Accordingly, this issue affects both Regions. On October 9, 2018, during an annual internal compliance review, the Entity determined that it did not have evidence to demonstrate that it had provided the required verified modeling information for its single Facility to its TPs by July 1, 2018. On October 11, 2018, the Entity submitted the required verified modeling information to its TPs, ending the noncompliance. The root cause of this issue is that the Entity did not have a sufficient process for tracking and documenting compliance with MOD-027-1 R2. Specifically, the Entity stated that the employee responsible for submitting the required verified modeling information had previously indicated that this task had been timely completed, but, after that employee was no longer employed with KPP, the Entity was unable to obtain evidence from its internal records or from its TPs indicating whether or not that this task had been timely completed. This noncompliance started on July 1, 2018, when MOD-027-1 R2 became enforceable, and ended on October 11, 2018, when the Entity submitted the required model information to its TPs.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk posed by this issue is that the Entity's TPs would not have accurate modeling information when performing system planning. In addition, the Entity's Facility is a combined cycle generator comprising four combustion turbines and one steam turbine, with a total nameplate rating of 1,662 MVA. However, the risk posed by this issue was reduced by the following factors. First, although the Entity did not timely provide the required verified modeling information to its TPs, that information had already been documented by the Entity and could have been provided to the TPs immediately if it had been requested. Second, the duration of the noncompliance was short, lasting from July 2018 through October 2018. Finally, after providing the verified modeling information to its TPs, the Entity did not receive any notifications from its TPs that the verified modeling information was not usable for system planning. No harm is known to have occurred. Texas RE considered the Entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the Entity: 1) provided the required verified modeling information to its TPs; 2) implemented new compliance task management software, which is used to track activities for compliance with MOD-027-1; and 3) provided training to the Entity's compliance personnel regarding tracking report submissions.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018020413	VAR-002-4.1	R3	Trent Wind Farm LP (TRENT)	NCR04148	03/28/2018	05/14/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 14, 2018, Trent Wind Farm LP (TRENT) submitted a Self-Report stating that, as a Generator Operator (GOP), it was in noncompliance with VAR-002-4.1 R3. Specifically, in two separate instances TRENT failed to notify its associated Transmission Operator (TOP) of a status change on its Automatic Voltage Regulator (AVR) within 30 minutes of the change. The first instance of noncompliance occurred on March 28, 2018, when TRENT's AVR was taken out of automatic voltage control mode without the knowledge of operators, and no notice was provided to the TOP of the status change. Operators were unaware of the AVR status changes due to intermittent faults, network communication errors, and an AVR status-tag configuration issue, each a result of ongoing wind farm repower activities. This instance of the noncompliance was discovered on April 3, 2018, when TRENT operators, communicating with the TOP, recognized that the AVR status-tag was not representing the proper status of the AVR. On April 3, 2018, TRENT wind farm was removed from service and placed in a Forced Outage. On April 5, 2018, TRENT completed repairs, placed the wind farm back in service, and worked with the TOP to confirm that the AVR status-tag and other issues were corrected, ending this instance of noncompliance. The second instance of noncompliance occurred on May 11, 2018, when the wind farm was returned to service without its AVR in automatic voltage control mode, and no notice was provided to the TOP. A review of the event log indicated that the wind farm was the subject of a Forced Outage on May 10, 2018, and that the AVR was taken out of automatic voltage control mode to facilitate maintenance and testing. The wind farm was returned to service on May 11, 2018, but the AVR was not returned to automatic voltage control mode, and no notification was made to the TOP. This instance of the noncompliance was discovered on May 14, 2018, when the TRENT Operations Manager identified that the AVR was not in automatic voltage control mode. Upon discovering the status of the AVR on May 14, 2018, the Operations Manager returned the AVR to automatic voltage control mode, and notified the TOP of the status change, ending this instance of noncompliance. The root cause of this noncompliance was poor communication between the Projects and Maintenance and Operations departments regarding TRENT's repowering activities and associated upgrades to its control systems. In the first instance of noncompliance, the lack of communication resulted in operators not being aware of the true status of the AVR. In the second, the lack of communication resulted in the AVR being left in a mode that was incorrect given that the Resource had been returned to service. The first instance of noncompliance began on March 28, 2018, when the status of TRENT's AVR changed and no notice was provided to the TOP, and ended on April 5, 2018, when TRENT worked with the TOP to confirm the status of the AVR. The second instance of noncompliance began on May 11, 2018, when the wind farm was returned to service without its AVR in automatic voltage control mode, and no notice was provided to the TOP, and ended May 14, 2018, when TRENT returned the AVR to automatic voltage control mode and notified the TOP of the status change.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. For the two instances of noncompliance, the AVR was not in automatic voltage control mode for a total of nine days, and a review confirmed that the facility operated within the site's voltage schedule during the period of noncompliance. No harm is known to have occurred. Texas RE considered TRENT's and its affiliate's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, TRENT: 1) returned the AVR to automatic voltage control mode and notified the TOP of the status change; and 2) conducted refresher training with Projects and Maintenance and Operations staff regarding plant Start-up procedures and AVR status. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018019885	COM-002-4	R4	Wind Energy Transmission Texas, LLC (WETT)	NCR11074	07/01/2017	12/31/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from February 26, 2018, through June 12, 2018, Texas RE determined that the Entity, as Transmission Operator (TOP), was in noncompliance with COM-002-4, R4. Specifically: (1) WETT did not assess adherence to the documented communications protocols in R1 by its operating personnel that issue and receive Operating Instructions and (2) WETT did not assess the effectiveness of its documented communications protocols in R1 for its operating personnel that issue and receive Operating Instructions. The first assessment pursuant to R4 should have been performed by July 1, 2017, but was not performed until December 31, 2017. The root cause of this issue was that WETT did not formally document a process to assess adherence and effectiveness of its documented communications protocols on an annual basis. This noncompliance started on July 1, 2017, when the first assessment pursuant to COM-002-4 R4 was due, and ended on December 31, 2017, when WETT performed an assessment of adherence to and effectiveness of its documented communication protocols and noted no deviations during its assessment.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. When WETT did perform an assessment of adherence to its documented communication protocols, no deviations were noted. Further, no instances were identified where use of WETT's documented communication protocols were ineffective. No harm is known to have occurred. Texas RE considered WETT's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, WETT: 1) performed an assessment of adherence to and effectiveness of its documented communication protocols; and 2) adopted a process to formally document its annual review of its communication protocols. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019413	PRC-023-3	R6; R6.2	Los Angeles Department of Water and Power (LDWP)	NCR05223	01/05/2017	09/01/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On March 19, 2018, LDWP submitted a Self-Report stating, as a Planning Authority (PA), it was in potential noncompliance with PRC-023-3 R6. LDWP had conducted its PRC-023-3 R6 assessment and three new circuits were identified and added to the list per application of Attachment B, Criteria B4 of the Standard. The list of circuits was subsequently reviewed and approved by LDWP management on December 5, 2016. However, on September 1, 2017, during its internal compliance audit LDWP discovered that it did not provide the list of three new circuits to WECC (its Regional Entity) and internally to its System Protection and Control Group (Transmission Owner, Generation Owner, and Distribution Provider), within 30 calendar days of the change to the list. However, LDWP provided the updated circuits list to its Reliability Coordinator, within the required timeframe of 30 calendar days. The root cause of the noncompliance was attributed to a lack of internal controls ensuring the successful completion of compliance tasks. Specifically, LDWP had a single point of failure in the one individual responsible for the process and that individual did not have a documented process flow. This noncompliance began on January 5, 2017, the first day after the 30-day deadline when the list of circuits was due to be sent and ended on September 1, 2017, when LDWP provided the list of circuits to the Generator Owner and Regional Entity in its Planning Coordinator area for a total of 240 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, LDWP failed to provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of a change to that list. Such failure could have resulted in inaccurate or incomplete planning assessments by entities within LDWP's Planning Coordinator area. The Facilities that were added exceeded the 115% loading and included two 230/130 kV banks and one 138 kV line. As such, without the new information, the entities within the Planning Coordinator area may not have been able to properly plan for the loading of the banks and line. However, LDWP implemented good detective controls to detect this issue. Specifically, LDWP performs internal compliance audits annually and detected this issue through its annual review. Further, LDWP's System Protection and Controls Group was aware of the three new Facilities being added to the preliminary list prior to the finalization of the official list in December 2016. This department also tracks all circuits independently from any notifications and had adjusted the relay settings at or above the loadability as specified in the Standard. Lastly, LDWP had provided the list to the RC. WECC considered LDWP's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, LDWP has: a) sent a notification with the updated circuits list to the Regional Entity and Generator Owner in their Planning Coordinator area; b) designated backup personnel for ensuring the completion of required activities per PRC-023 R6; and c) conducted additional compliance training to personnel responsible for PRC-023 R6 addressing NERC's risk-based framework, evaluation of internal controls, and internal process flow to ensure personnel understand how to fulfill the requirement. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019371	PRC-005-2(i)	R3	Tri-State Generation and Transmission Association – Reliability (TSGT)	NCR10030	03/01/2016	12/6/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On March 8, 2018, TSGT submitted a Self-Report stating that, as a as a Generator Owner, it was in potential noncompliance with PRC-005-2(i) R3. TSGT submitted the Self-Report to WECC under an existing multi-region registered entity agreement. On February 26, 2018, while preparing for an audit, TSGT discovered that it did not test the terminal connection resistance and the unit to unit connection resistance of three Vented Lead-Acid (VLA) battery banks at a generating station within the 18-calendar month interval prescribed within PRC-005-2(i) R3, Table 1-4(a). TSGT scheduled work orders for testing its VLA battery banks in a work management system for testing and maintenance to be performed on an annual basis, by August 31st. However, on September 20, 2016, TSGT's planning personnel erroneously closed out the annual work orders for 2015 and 2016 testing in the software management system which indicated the new work order was to replace the two original work orders. TSGT's test records indicated that the previously completed testing was done on August 31, 2014. This noncompliance began on March 1, 2016, when TSGT missed the 18-calendar month maximum maintenance interval for the three VLA battery banks and ended on December 6, 2017, when testing for all three VLA battery banks was completed, for a total of 645 days. The root cause of this noncompliance was attributed to TSGT's lack of internal controls to ensure compliance with the Standard Requirement and poor status tracking of tasks for performing PRC-005-2(i) R3.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, TSGT failed to maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Table 1-4(a) in the Standard when the entity failed to maintain three Vented Lead-Acid (VLA) battery banks within 18 calendar months. Failure to test the terminal connection resistance and the unit to unit connection resistance of three VLA battery banks could result in the failure of the batteries at the generating station and could result in a failure of the protection systems at the generating station and potentially a loss in 1,552 MVA of coal generation. However, as compensation, TSGT's battery charger and batteries are configured in parallel so both supply power to the Protection Systems. Additionally, TSGT has over 7000 Protection System components and the three affected batteries make up less than 5% of its total components, further reducing the risk. WECC considered the TSGT's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, TSGT has: 1. completed the terminal connection resistance and unit to unit connection resistance testing for three VLA battery banks; 2. created reporting capabilities through TSGT's work management system; 3. created daily supervisor reports to inform management of compliance related work orders and corresponding due dates; and 4. created auto notifications to inform compliance personnel if a work order exceeds the expected completion date. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019342	PRC-005-6	R3	Turlock Irrigation District (IID)	NCR05435	10/01/2017	01/25/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On March 2, 2018, TID submitted a Self-Report stating that, as a Transmission Owner, it was in potential noncompliance with PRC-005-6 R3. In January 2018, as part of its internal compliance program's self-certification process, TID discovered that it did not inspect one Valve-Regulated Lead-Acid (VRLA) station battery at a 115kV substation within the six-calendar month interval prescribed within PRC-005-6 R3, Table 1-4(b). TID scheduled the inspection work order in its manually prepared schedule for September 2017. However, TID's support personnel erroneously removed the work order task from the technician's work schedule. TID's test records indicated that the previously completed testing was done during March of 2017. The root cause of the noncompliance was attributed to inadequate follow up by personnel responsible for maintenance activities associated with PRC-005-6 R3. This noncompliance began on October 1, 2017, when TID missed the six-calendar month inspection maintenance deadline for one VRLA station battery and ended on January 25, 2018, when TID completed the inspection maintenance activities on the VRLA station battery, for a total of 116 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, TID failed to maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Table 1-4(a) in the Standard when the entity failed to maintain one Valve-Regulated Lead-Acid (VRLA) station battery at one 115 kV substation within six calendar months. Failure to inspect one VRLA battery system could result in the loss of BPS equipment in one substation that is less than 200 kV. However, as compensation, TID's charging voltage for this station battery is alarmed and monitored remotely and would have alerted TID personnel to battery performance concerns. Additionally, one VRLA station battery makes up less than 5% of TID's total Protection System components, further reducing the risk. WECC considered TID's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, TID has: a) completed the battery maintenance on the VRLA station battery; b) provided additional training to personnel responsible for work schedule accuracy; and c) implemented management reviews of maintenance schedule. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020554	PRC-023-4	R1	MidAmerican Energy Company (MEC)	NCR00824	08/15/2018	01/30/2019	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 9, 2018, MEC submitted a Self-Log stating that, as a Transmission Owner, it was in noncompliance with PRC-023-4 R1. After the submission of the Self-Log, MEC self-identified another instance of noncompliance. In the first instance of noncompliance, MEC submitted a Self-Log stating that through an internal control related to updating FAC-008 ratings, it discovered two relays that were set to operate at or below 150% of the highest seasonal Facility Rating. This instance of noncompliance was caused because MEC failed to follow its process to conduct a system protection review to evaluate relay settings for compliance with PRC-023 prior to issuing the revised equipment ratings. In the second instance of noncompliance, MEC reported that it discovered two additional relays (primary and secondary relays for a single circuit) had a setting to operate at exactly 150% of the highest seasonal Facility Rating. This instance of noncompliance was caused because the screening equation was inadequate. The screening equation used was "greater than or equal to" 150%, when it should have been "greater than" 150%. Therefore, the screening equation did not alert system protection engineers that the relays were set at exactly 150%. The noncompliance began on August 15, 2018, when the first relay was set to operate at or below 150% of the highest seasonal Facility Rating, and ended on January 30, 2019 when the relay settings in instance two were revised.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The noncompliance was minimal, because per MEC, it conducted an extent of condition review and found no other relays with loadability limits set at 150% or below, and the noncompliance was limited to the relay load limits infringement being set at 149.97% for the circuit's winter rating. Additionally, the issue was detected by an internal control and corrected prior to utilization of that limit during a winter season. For instance two, the relay load limits were set at 150% respectively of the highest seasonal rating. The variances for both instances would only have a negligible impact on the System Operator's ability to identify and correct possible overloads, consistent with the purpose of PRC-023. No harm is known to have occurred.
Mitigation	To mitigate the first instance of noncompliance, MEC: 1) corrected settings were issued for one of the relays while other relay was removed from service due to a bad contact; and 2) issued reminders to its system planning personnel to follow its existing process to initiate ratings reviews and compliance verifications prior to releasing revised facility ratings. To mitigate the second instance of noncompliance, MEC: 1) revised settings the day of discovery; 2) updated settings in the field; and 3) reviewed screening equations and all occurrences of "greater than or equal to 150%" were replaced with "greater than 150%."

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2019021537	COM-002-4	R3	Minnesota Power (Allete, Inc.) (MP)	NCR00674	05/22/2018	05/24/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On April 10, 2019, MP submitted a Self-Log stating that, as a Distribution Provider and a Generator Operator, it was in noncompliance with COM-002-4 R3. Per MP, a relay technician, who had not completed the required training, performed 12 operating instructions on distribution breakers that are part of a UFLS at different BES substations The cause of the noncompliance was MP did not have sufficient internal controls in place to validate that all relay technicians receiving operating instructions had completed the required qualified switch training (QST). The noncompliance began on May 22, 2018, when the untrained individual began receiving operating instructions, and ended on May 24, 2018, when the operating personnel was removed from the role of receiving operating instructions until the training could be performed.
Risk Assessment	The issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). MP reported that there was no Real-time impact, as changes to the UFLS were completed under the supervision of a relay technician that was trained on the MP operating protocols. MP's procedure ensures that UFLS changes that occur in the field are documented by the field personnel and then reviewed and signed off by a Relay Engineer, reducing the likelihood of errors. The employee conducted the three-way communication process successfully while receiving the operating instructions. Also, the risk was limited to the three-day window in which the operating personnel received and implemented operating instructions before being removed from this responsibility until training was complete. Lastly, an internal review of all qualified switch persons was completed with the help of Human Resources and no other issues were identified. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, MP: 1) removed the employee from the field until training was complete; 2) sent an email to all supervisors of field personnel reminding them of the need to sign off on QST and COM-002 training; 3) provided operators training on the importance of reviewing the QST list before issuing Operating Instructions; and 4) created an internal control that sends an automated email notification for employees assigned to QST or COM-002 training within MP's Learning Management System (LMS). This automated email notifies the Supervisor - System Operations, the Trainer - System Operations, and the supervisors of the employees required to complete the training due to a change in job responsibilities as well as verifies if there should be any changes to learning assignments in the LMS.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2019020993	BAL-003-1.1	R2	Northern States Power (Xcel Energy) (NSP)	NCR01020	6/8/2018	8/20/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 10, 2019, the Entity submitted a Self-Log stating that, as Balancing Authority, it was in noncompliance with BAL-003-1.1 R2. NSP, Public Service Company of Colorado (PSCO) (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program. Xcel Energy reported that on June 8, 2018, the frequency bias setting used in the PSCO EMS reverted from the validated 2018 value (-72.3 MW/0.1Hz) to the 2017 value (-78MW/0.1Hz). Xcel Energy reported that it discovered the noncompliance during an investigation into deviations (approximately 4 MW) in its accumulated inadvertent interchange. Xcel Energy stated that an incorrect software setting prevented the propagation of the updated 2018 frequency bias from the EMS system into the backup EMS system. A planned cutover test to the backup EMS system resulted in the 2017 value being carried back over into the EMS system after the test. The cause of the noncompliance was an incorrect software setting causing a reversion to the 2017 value and no verification of the frequency bias setting after a cutover was complete. The noncompliance began on June 8, 2018, when the validated 2018 frequency bias setting reverted to the 2017 setting, and ended on August 20, 2018, when the frequency bias setting was corrected.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The magnitude of the error was less than 6MW/0.1 Hz and resulted in the production of a slightly larger and more conservative Area Control Error (ACE). No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, Xcel Energy: 1) corrected the frequency bias setting; 2) corrected the propagation filed setting that prevented the correct setting from being propagated in the backup EMS system; and 3) updated the cutover procedure to include a step to verify the frequency bias value in the primary and backup EMS.

NERC Noncompliance ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Mitigation Completion Date
NPCC2019021736	PRC-005-2	R3	Rumford Power Inc.	NCR11130	4/1/2015	4/5/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On June 25, 2019, Rumford Power Inc. ("the Entity") submitted a self-report stating that, as a Generator Owner ("GO"), it was in noncompliance with PRC-005-1b R2. Based on additional information received from the Entity, NPCC has determined that PRC-005-2 R3 is more appropriate for processing this potential noncompliance. On March 21, 2019, Rumford Power Inc's assets ownership transferred to a new owner, which conducted an internal compliance gap assessment. As a result of the internal compliance gap assessment completed on June 20, 2019, the Entity concluded that it did not have adequate documentation to demonstrate compliance with the full scope of testing requirements for its batteries, per Table 1-4(a) of the standard. The Entity owns three Vented Lead-Acid (VLA) type battery banks, all of which are affected by this instance of noncompliance. Specifically, the noncompliance has the following aspects: a. Electrolyte Level and Unintentional Grounds (items that have a maximum maintenance interval of four calendar months) were inspected but not properly documented; b. Cell Condition of all battery cells and Physical Condition of Battery Rack (items that have a maximum maintenance interval of eighteen calendar months) were inspected but not properly documented; and c. Battery Terminal Connection Resistance and Battery Inter-cell or unit-to-unit connection resistance (items that have a maximum maintenance interval of eighteen calendar months) were not completed. NPCC determined that this noncompliance spans multiple versions of the Reliability Standard, as follows: • PRC-005-2 R3, from April 1, 2015 until May 28, 2015 (the standard's retirement date); • PRC-005-2(i) R3, from May 29, 2015 until December 31, 2016 (the standard's retirement date); and • PRC-005-6 R3, from January 1, 2016 until April 5, 2018, when the Entity completed all missed tests for its three VLA-type battery banks. NPCC further determined that, for purposes of this noncompliance, there was no substantive change in the Entity's compliance obligations under the three applicable Standard Requirements. The root cause of this instance of noncompliance was lack of proper documentation resulting from battery inspection recording forms that were not sufficiently detailed to demonstrate compliance with Table 1-4(a) of standard PRC-005-2.
Risk Assessment	This violation posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Maintenance performed at intervals longer than required may result in deterioration of battery performance and/or lack of proper DC voltage at a substation, which could cause protection systems to misoperate or failing to operate when required in order to isolate electrical faults. However, the Entity's single generating station is equipped with devices that continuously monitor Station DC Supply Voltage and are also programmed to annunciate abnormal voltage conditions to a control room that is occupied by two operators 24 hours per day, 365 days per year. In addition, by the Fall of 2017, the Entity completed replacement of its ageing three battery banks with new in-kind units that were fully tested at commissioning and subsequently re-tested in accordance with required maintenance activities and timelines specified in Table 1-4(a) of the standard. The Entity owns two generating facilities that are in scope of the standard, a Gas Turbine and a Steam Turbine, which are normally operated as a single Combined Cycle plant. The facilities are interconnected to a 115 kV substation owned by the Host TO. The Entity's two generating facilities have a combined rated capacity of approximately 265 MW. The combined average annual capacity factors for the two units have been 10.3% (in 2017), 6.7% (in 2018) and 0.1% (in 2019, to date). By comparison, the Entity's Reliability Coordinator (ISO-NE) carries required Operating Reserves of approximately 2600 MW and could have adequately compensated for generation outages potentially arising from this instance of noncompliance. No actual harm is known to have occurred. NPCC considered the Entity's compliance history and determined there are no prior relevant instances of noncompliance.
Mitigation	To mitigate the noncompliance, the Entity: • completed all missed tests for its three VLA-type battery banks; • implemented an internal control consisting of a NERC Management Checklist that instructs responsible staff to manually review, on a monthly basis, PRC-005-2 (and beyond) required testing among other NERC compliance obligations; and • implemented the use of automated preventive maintenance reminders for compliance tasks that will need to be completed by the 14th of each month.

NERC Noncompliance ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Mitigation Completion Date
NPCC2019021737	PRC-005-6	R5	Rumford Power Inc.	NCR11130	4/27/2016	9/24/2019	Self-Report	9/24/2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On June 25, 2019, Rumford Power Inc. ("the Entity") submitted a self-report stating that, as a Generator Owner ("GO"), it was in noncompliance with PRC-005-6 R5. On March 21, 2019, Rumford Power Inc's assets ownership transferred to a new owner, which conducted an internal compliance gap assessment. As a result of the internal compliance gap assessment completed on June 20, 2019, the Entity concluded that it did not have adequate documentation to demonstrate efforts to correct the tripping time of a Steam Turbine generator auxiliary relay that had been tested in 2016 to be approximately 1 millisecond ("ms") slower than its design value. Specifically, on April 27, 2016, an engineering assessment performed for the Entity for compliance purposes related to standard PR-005-1 determined that the actual tripping time of the Gas Turbine generator "94GB-1 GE HFA" relay was 8.9 ms versus its design value of 8 ms. At that time, the Entity did not make any effort to correct this discrepancy. This noncompliance started on April 27, 2016, when the Entity failed to make efforts to correct the aforementioned unresolved maintenance issue and will end on September 24, 2019, the date when the Entity has scheduled the replacement of its defective "94GB-1 GE HFA" relay with a new unit. The root cause of this instance of non-compliance was the Entity's lack of proper documentation, specifically the failure to make and document efforts to address unresolved maintenance issues.
Risk Assessment	This violation posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. A slow responding relay that does not operate within its intended time frame may, in the event of an electrical fault, compromise the correct operation of the primary protection system (i.e. Normal Fault Clearing) and initiate, instead, a Delayed Fault Clearing scheme requiring other backup relaying to activate to clear the fault. The potential thus exists for more system facilities to unnecessarily be tripped out of service when a relay does not trip in accordance with design tripping times. However, the relay in question provides back up activation to the main trip coil of a 115 kV breaker protecting the Gas Turbine generator. Another relay, which provides primary activation to the same main trip coil, has consistently been tested as correctly operating per its own design tripping times. Therefore, in this particular case, delayed clearing of a potential electrical fault would only occur if both the primary and secondary relays fail to operate per their respective design tripping times. According to historical testing and operational data, the Gas Turbine generator protection has operated in the Normal Fault Clearing mode each time it has been required to operate. The Entity owns two generating facilities that are in scope of the standard, a Gas Turbine and a Steam Turbine, which are normally operated as a single Combined Cycle plant. The facilities are interconnected to a 115 kV substation owned by the Host TO. The Entity's two generating facilities have a combined rated capacity of approximately 265 MW. The combined average annual capacity factors for the two units have been 10.3% (in 2017), 6.7% (in 2018) and 0.1% (in 2019, to date). By comparison, the Entity's Reliability Coordinator (ISO-NE) carries required Operating Reserves of approximately 2600 MW and could have adequately compensated for unnecessary generation outages potentially arising from this instances of noncompliance when electrical faults occur. No actual harm is known to have occurred. NPCC considered the Entity's compliance history and determined there are no prior relevant instances of noncompliance.
Mitigation	To mitigate the noncompliance, the Entity: • on September 24, 2019, will replace the defective relay with a new unit; • implemented an internal control consisting of a NERC Management Checklist that instructs responsible staff to manually review, on a monthly basis, PRC-005-6 required testing among other NERC compliance obligations; and • implemented the use of automated preventive maintenance reminders for compliance tasks that will need to be completed by the 14th of each month.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018019870	MOD-025-2	R1	Baconton Power LLC (BACNTN)	NCR01178	07/01/2016	06/27/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 19, 2018, BACNTN submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R1. BACNTN failed to provide its Transmission Planner (TP) with verification of the Real Power capability of its applicable Facilities in accordance with the NERC Implementation Plan. During a review, the plant manager and compliance contractor discovered that BACNTN was no longer exempt under MOD-025-2 R1 as with the case under the previous MOD-024-1 and MOD-025-1 Standards which were retired. Under the previous Standards, SERC developed procedures for verification of the generators Real Power capabilities in its region. The procedures from SERC created exemptions that BACNTN met and the verifications for the Real Power capability were not required. As of July 1, 2016, the Implementation Plan required 40% compliance of applicable units and BACNTN was 0% compliant. This noncompliance started on July 1, 2016, when the Standard became mandatory and enforceable, and BACNTN failed to provide its TP staged verification data for Real Power capability of its generating units in accordance with Attachment 1, and ended on June 27, 2018, when BACNTN provided its TP with verification of the Real Power capability of its units. The cause of the noncompliance was a lack of effective internal controls when MOD-025-2 R1 became effective and BACNTN overlooked the new Standard during its quarterly compliance reviews. BACNTN failed to realize it was no longer able to take the exemption for Real Power testing under the previous MOD-024-1 and MOD-025-1.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). BACNTN's failure to provide verification data from a staged test and timely data from the staged test could have resulted in inaccurate system models. BACNTN's four Combustion Turbine units total generation of 287 MVA, and the average three-year capacity factor of 1.65%, BACNTN has minimal impact to the BPS. No harm is known to have occurred. SERC considered BACNTN's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, BACNTN: 1) completed MOD-025-2 R1 Real Power testing and submit to its TP; 2) added a preventive maintenance task in its maintenance tracking system for the testing to be completed every five years per the standard; and 3) included third-party contractor in quarterly compliance review to provide updates for new and existing standards and requirements.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018019871	MOD-025-2	R2	Baconton Power LLC (BACNTN)	NCR01178	07/01/2016	06/27/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 19, 2018, BACNTN submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R2. BACNTN failed to provide its Transmission Planner (TP) with verification of the Reactive Power capability of its applicable Facilities in accordance with the NERC Implementation Plan. During a review, the plant manager and compliance contractor discovered that BACNTN was no longer exempt under MOD-025-2 R2 as with the case under the previous MOD-024-1 and MOD-025-1 Standards which were retired. Under the previous Standards, SERC developed procedures for verification of the generators Reactive Power capabilities in its region. The procedures from SERC created exemptions that BACNTN met and the verifications for the Reactive Power capability were not required. As of July 1, 2016, the Implementation Plan required 40% compliance of applicable units and BACNTN was 0% compliant. This noncompliance started on July 1, 2016, when the Standard became mandatory and enforceable, and BACNTN failed to provide its TP staged verification data for Reactive Power capability of its generating units in accordance with Attachment 1, and ended on June 27, 2018, when BACNTN provided its TP with verification of the Reactive Power capability of its units. The cause of the noncompliance was a lack of effective internal controls when MOD-025-2 R2 became effective and BACNTN overlooked the new Standard during its quarterly compliance reviews. BACNTN failed to realize it was no longer able to take the exemption for Reactive Power testing under the previous MOD-024-1 and MOD-025-1.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). BACNTN's failure to provide verification data from a staged test and timely data from the staged test could have resulted in inaccurate system models. BACNTN's four Combustion Turbine units total generation of 287 MVA, and the average three-year capacity factor of 1.65%, BACNTN has minimal impact to the BPS. No harm is known to have occurred. SERC considered BACNTN's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, BACNTN: 4) completed MOD-025-2 R2 Reactive Power testing and submit to its TP; 5) added a preventive maintenance task in its maintenance tracking system for the testing to be completed every five years per the standard; and 6) included third-party contractor in quarterly compliance review to provide updates for new and existing standards and requirements.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021314	MOD-025-2	R1	Cottonwood Energy Company, LP (Cottonwood)	NCR01210	07/01/2016	10/28/2016	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On April 5, 2019, Cottonwood submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R1. Cottonwood failed to provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities in accordance with the NERC Implementation Plan. On February 4, 2019, a change in ownership of the Cottonwood facility occurred, and on February 25 2019, the new ownership of Cottonwood began a compliance review, which discovered the noncompliance that led to the Self-Report. The Cottonwood facility consists of four Combustion Turbines (CTs), CT 1 through 4 each with a 234 MVA rating, and four Steam Turbines (STs), ST 1 through 4 each with a 187.65 MVA rating, operated as combined cycle units. On March 11, 2016, Cottonwood took its facility off line due to potential flooding along the Sabine River. Following the units coming offline, flooding occurred at the Cottonwood facility, an associated substation, and a neighboring substation, which caused substantial damage to all CTs and STs. On July 1, 2016, all units were inoperable and Cottonwood had not completed any MOD-025-2 R1 verifications. The Implementation Plan called for 40% compliance of applicable units and Cottonwood had 0% compliance. Between August 4, 2016 and September 24, 2016, Cottonwood completed repairs on all CTs and STs and returned the units to service. On October 28 2016, Cottonwood tested all CTs, representing 50% of Cottonwood’s applicable units, for Real Power capability and submitted the results to its Transmission Planner (TP). On February 28 2017, Cottonwood tested all STs and submitted the results to its TP. On this date, Cottonwood verified the Real Power capability for 100% compliance. This noncompliance started on July 1, 2016, when Cottonwood failed to provide its TP with verification of the Real Power, as required by the NERC Implementation Plan, and ended on October 28, 2016, when Cottonwood submitted more than 40% of the required data. The root cause of the noncompliance was long term outages of applicable units due to flooding, which necessitated repair prior to completion of verification testing. While Cottonwood was aware of the Standard and Requirement, it was unable to run the appropriate studies to provide the information to the TP while the units were inoperable.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Cottonwood’s failure to verify Real Power capability could have led to inaccurate planning models. However, due to the unforeseen unit damage, any inaccuracies of the planning model was minimal as the units were offline. Additionally, Cottonwood prioritized the verification as soon as the units returned to service and mitigated the noncompliance a month after the returned to service. Finally, the total affected generation was 1123 MVA, a small sum within planning studies. No harm is known to have occurred. SERC considered Cottonwood’s compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Cottonwood: 1) tested the four CT’s and submitted the completed form to the Transmission Planner. This represented 50 percent of the registration testing in accordance with MOD-025-2; and 2) built a flood wall to prevent future flooding.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021315	MOD-025-2	R2	Cottonwood Energy Company, LP (Cottonwood)	NCR01210	07/01/2016	10/28/2016	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On April 5, 2019, Cottonwood submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R2. Cottonwood failed to provide its Transmission Planner (TP) with verification of the Reactive Power capability of its applicable Facilities in accordance with the NERC Implementation Plan. On February 4, 2019, a change in ownership of the Cottonwood facility occurred, and on February 25 2019, the new ownership of Cottonwood began a compliance review, which discovered the noncompliance that led to the Self-Report. The Cottonwood facility consists of four Combustion Turbines (CTs), CT 1 through 4 each with a 234 MVA rating, and four Steam Turbines (STs), ST 1 through 4 each with a 187.65 MVA rating, operated as combined cycle units. On March 11, 2016, Cottonwood took its facility off line due to potential flooding along the Sabine River. Following the units coming offline, flooding occurred at the Cottonwood facility, an associated substation, and a neighboring substation, which caused substantial damage to all CTs and STs. On July 1, 2016, all units were inoperable and Cottonwood had not completed any MOD-025-2 R1 verifications. The Implementation Plan called for 40% compliance of applicable units and Cottonwood had 0% compliance. Between August 4, 2016 and September 24, 2016, Cottonwood completed repairs on all CTs and STs and returned the units to service. On October 28 2016, Cottonwood tested all CTs, representing 50% of Cottonwood's applicable units, for Reactive Power capability and submitted the results to its Transmission Planner (TP). On February 28 2017, Cottonwood tested all STs and submitted the results to its TP. On this date, Cottonwood verified the Reactive Power capability for 100% compliance. This noncompliance started on July 1, 2016, when Cottonwood failed to provide its TP with verification of the Reactive Power, as required by the NERC Implementation Plan, and ended on October 28, 2016, when Cottonwood submitted more than 40% of the required data. The root cause of the noncompliance was long term outages of applicable units due to flooding, which necessitated repair prior to completion of verification testing. While Cottonwood was aware of the Standard and Requirement, it was unable to run the appropriate studies to provide the information to the TP while the units were inoperable.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Cottonwood's failure to verify Reactive Power capability could have led to inaccurate planning models. However, due to the unforeseen unit damage, any inaccuracies of the planning model was minimal as the units were offline. Additionally, Cottonwood prioritized the verification as soon as the units returned to service and mitigated the noncompliance a month after the returned to service. Finally, the total affected generation was 1,123 MVA, a small sum within planning studies. No harm is known to have occurred. SERC considered Cottonwood's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Cottonwood: 1) tested the four CT's and submitted the completed form to the Transmission Planner. This represented 50 percent of the registration testing in accordance with MOD-025-2; and 2) built a flood wall to prevent future flooding.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021215	COM-002-4	R1, R1.5, R1.6	Cube Hydro Carolinas, LLC (Cube)	NCR01169	07/01/2016	03/18/2019	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from February 26, 2019 to March 14, 2019, SERC determined that Cube, as Balancing Authority and Transmission Operator, was in noncompliance with COM-002-4 R1. Cube failed to develop a documented communications protocol that specified the instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification, as required by NERC Standard COM-002-4 R1, R1.5. Additionally, Cube failed to develop a documented communications protocol that specified the nomenclature for Transmission Interface Elements and Transmission Interface Facilities when issuing an oral or written Operating Instruction, as required by NERC Standard COM-002-4 R1, R1.6. During the Compliance Audit, Cube presented two documents related to COM-002-4 R1. The Operating Personnel Communication Protocols (CP) is a controlled document and compliance artifact intended to meet the requirements of COM-002-4. The Associated Communication Protocol document (ACP) is an Operator guide intended as a reference on the real time desk. The CP did not reference or incorporate the ACP in any way. The CP restated the requirements for COM-002-4 verbatim. The ACP had two bullet points related to COM-002-4 R1.5 and R1.6. They clearly specified a date/time (e.g., June 4, 2016 at 15:00 if the action was for the future or at 15:00 if the action was for the same day) when punctual actions were needed and used specified nomenclature for Transmission interface facilities. However, the ACP failed to specify the instances that require time identification ("punctual actions" is not defined) and format for that identification (format is alluded to but not listed) (R1.5). Additionally, the ACP failed to specify nomenclature for Transmission Interface Elements/Facilities (R1.6). This noncompliance started on July 1, 2016, when COM-002-4 became enforceable and Cube's documentation failed to meet R1.5 and R1.6, and ended on March 18, 2019, when Cube updated the documentation to properly reflect how to document time and nomenclature for Transmission Interface Elements/Facilities. The root cause of the noncompliance was a failure to appropriately document the actions to be taken by Operators when issuing Operation Instructions. For time identification, Cube relied solely on training to ensure common identification. For nomenclature, Cube relied on the Operator's institutional knowledge to know and use the proper common line identifier for their limited number of lines.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Cube's improperly documented practices could have caused confusion leading to the mishandling of an Operating Instruction. However, Cube had three total interconnection lines, a total of less than 19 miles of 100kV transmission, and infrequently issued Operating Instructions. No harm is known to have occurred. SERC considered Cube's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Cube: 1) modified the Communication Protocols to include the Associated Communication Protocol document as an Attachment; 2) modified the Associated Communication Protocol to clarify specifics around time identification and nomenclature for Transmission Interface Elements/Facilities to be used in all instances of issuing or receiving Operations Instructions; 3) presented the Communication Protocols, Associated Communication Protocol, and VACAR South RC Restoration Plan to the system operators; and 4) confirmed that operators reviewed and understood the training and Communication Protocol.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021216	PRC-019-2	R1	Cube Hydro Carolinas, LLC (Cube)	NCR01169	07/01/2016	11/13/2018	Compliance Audit	Complete

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from February 26, 2019 through March 14, 2019, SERC determined that the entity, as a Generator Owner, was in noncompliance with PRC-019-2 R1. SERC determined that Cube failed to complete coordination of the voltage regulating system controls, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions, in accordance with the NERC Standard PRC-019-2 R1 Implementation Plan. On July 1, 2016, the Implementation Plan for PRC-019-2 R1 stated that 40% of applicable facilities needed to be compliant. On that date, Cube had completed 0% of coordination activities. On October 31, 2016, Cube completed coordination of Unit 1 and Unit 2, meaning that Cube had 50% of applicable facilities compliant on that date. No adjustments were required for either unit. On July 1, 2017, the Implementation Plan stated that 60% of applicable facilities needed to be compliant. With only 50% of applicable facilities appropriately coordinated, Cube became noncompliant again. On July 1, 2018, the Implementation Plan stated that 80% of applicable facilities needed to be compliant and Cube remained noncompliant. On November 13, 2018, Cube completed coordination of Unit 3 and Unit 4, meaning that Cube had 100% of applicable facilities compliant on that date. No adjustments were required for either unit. SERC determined that Cube failed to coordinate at least 40% of applicable facilities by July 1, 2016, though it did return to compliance on October 31, 2016. Cube then failed to coordinate at least 60% of applicable facilities by July 1, 2017, and 80% of applicable facilities by July 1 2018 as prescribed by the NERC Standard PRC-019-2 R1 Implementation Plan. This first instance started on July 1, 2016, when Cube failed to coordinate its voltage regulating system controls, and ended on October 31, 2016, when Cube had 50% of applicable facilities compliance. The second instance started on July 1, 2017, when Cube failed to coordinate 80% of its voltage regulating system controls, and ended on November 13, 2018, when Cube finished coordination on 100% of its applicable units. The root cause of the noncompliance was a lack of effective internal controls to correctly interpret NERC Standards and their effective dates and the associated Implementation Plan. Cube internally miscalculated the Implementation Dates and had no control to verify and/or flag the mistake.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Cube's failure to coordinate voltage regulating equipment could have led to unintentionally tripping or equipment damage. Cube has four applicable facilities subject to PRC-019-2 R1. Cube's total nameplate rating for applicable generators is approximately 160 MVA (0.05% of generation in SERC) and connects to the BES at point of 120kV or below. No harm is known to have occurred. SERC considered Cube's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Cube: 1) completed initial testing of the four applicable facilities; 2) created a process to ensure the Subject Matter Expert and compliance staff are in agreement with future implementation deadlines; 3) created tasks to review the SERC FAQ process during implementation date verification; 4) performed training, with signoffs, on the new process; and 5) added verifications to the maintenance schedule and compliance calendar.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021361	PRC-024-2	R1.	Cube Hydro Carolinas, LLC (Cube)	NCR01169	07/01/2016	09/21/2016	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On April 17, 2019, Cube submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R1. Cube failed to set its protective relaying such that the generator frequency protective relaying did not trip the applicable generating units as a result of a frequency excursion caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 1, in accordance with the NERC Implementation Plan. On March 2, 2019, Cube discovered the noncompliance as part of a review of Implementation Plans. On July 1, 2016, the Implementation Plan for PRC-024-2 stated that 40% of applicable facilities needed to be compliant. On that date, Cube had completed 25% of coordination activities. On September 21, 2016, Cube completed its review of frequency protective relays for all units, in accordance with the "no trip zone", of PRC-024 Attachment 1, which returned Cube to compliance. No setting changes were required for compliance but Cube chose to update the setting for one unit to match the most recent relay testing sheets. This noncompliance started on July 1, 2016, when Cube failed to set voltage protective relays in accordance with PRC-024-2, and ended on September 21, 2016, when Cube finished reviewing the voltage protective relays on 100% of its applicable units. The root cause of the noncompliance was a lack of effective internal controls to correctly interpret NERC Standards and their effective dates and the associated Implementation Plan. Cube internally miscalculated the Implementation Dates and had no control to verify and/or flag the mistake.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Cube's failure to appropriately set voltage protective relays could have led to tripping in the "no trip zone" or equipment damage. Cube has four applicable facilities subject to PRC-024-2. Cube's total nameplate rating for applicable generators is approximately 160 MVA (0.05% of generation in SERC) and it was only in noncompliance for two months. No harm is known to have occurred. SERC considered Cube's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Cube: 1) set protective relays so there were not in the "No Trip Zone"; 2) created a process to ensure the Subject Matter Expert and compliance staff are in agreement with future implementation deadlines; 3) created tasks to review the SERC FAQ process during implementation date verification; 4) performed training, with signoffs, on the new process; and 5) added verifications to the maintenance schedule and compliance calendar.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021362	PRC-024-2	R2	Cube Hydro Carolinas, LLC (Cube)	NCR01169	07/01/2016	09/21/2016	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On April 17, 2019, Cube submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R2. Cube failed to set its protective relaying such that the generator voltage protective relaying did not trip the applicable generating units as a result of a voltage excursion caused by an event on the transmission system, external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2, in accordance with the NERC Implementation Plan. On March 2, 2019, Cube discovered the noncompliance as part of a review of Implementation Plans. On July 1, 2016, the Implementation Plan for PRC-024-2 stated that 40% of applicable facilities needed to be compliant. On that date, Cube had completed 25% of coordination activities. On September 21, 2016, Cube completed its review of voltage protective relays for all units, in accordance with the "no trip zone", of PRC-024 Attachment 2, which returned Cube to compliance and compliant with all future Implementation Plan due dates. This noncompliance started on July 1, 2016, when Cube failed to set voltage protective relays in accordance with PRC-024-2, and ended on September 21, 2016, when Cube finished reviewing the voltage protective relays on 100% of its applicable units. The root cause of the noncompliance was a lack of effective internal controls to correctly interpret NERC Standards, the Effective Dates, and the associated Implementation Plan. Cube internally miscalculated the Implementation Dates and had no control to verify and/or flag the mistake.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Cube's failure to appropriately set voltage protective relays could have led to tripping in the "no trip zone" or equipment damage. Cube has four applicable facilities subject to PRC-024-2. Cube's total nameplate rating for applicable generators is approximately 160 MVA (0.05% of generation in SERC) and it was only in noncompliance for two months. No harm is known to have occurred. SERC considered Cube's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Cube: 1) set protective relays so there were not in the "No Trip Zone"; 2) created a process to ensure the Subject Matter Expert and compliance staff are in agreement with future implementation deadlines; 3) created tasks to review the SERC FAQ process during implementation date verification; 4) performed training, with signoffs, on the new process; and 5) added verifications to the maintenance schedule and compliance calendar.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021399	MOD-025-2	R1	Cube Hydro Carolinas, LLC (Cube)	NCR01169	07/01/2016	11/27/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On April 19, 2019, Cube submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R1. Cube failed to provide its Transmission Planner (TP) with verification of the Reactive Power capability of its applicable Facilities in accordance with the NERC Implementation Plan On March 2, 2019, Cube discovered the noncompliance as part of a review of Implementation Plans. As of July 1, 2018, the Implementation Plan for MOD-025-2 stated that 80% of applicable facilities needed to be compliant. On that date, Cube had completed 0% of coordination activities. On November 26, 2018, Cube performed Real Power capability on all applicable units and on November 27, 2018, Cube submitted the Real Power capability results to its TP. Cube misinterpreted the NERC Implementation Plan to have two phases over the five year period. Specifically, Cube believed that it was required to be 50% compliant on January 1, 2019 and 100% compliant on July 1, 2020. This noncompliance started on July 1, 2016, when Cube failed to submit Real Power verification to its TP and ended on November 27, 2018, when Cube performed the Real Power verification and submitted the results to its TP. The cause of the noncompliance was a lack of effective internal controls to correctly interpret NERC Standards and their effective dates and Implementation Plan. Cube misinterpreted the Implementation dates and had no control to verify and/or flag the mistake.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Cube's failure to submit generation data to its TP could have led to inaccurate planning models, which in turn could have caused incorrect resource adequacy studies and interconnection studies. Cube has four applicable facilities subject to MOD-025-2. Cube's total nameplate rating for applicable generators is approximately 160 MVA (0.05% of generation in the SERC Region) which limits the exposure. No harm is known to have occurred. SERC considered Cube's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Cube: 1) performed verification of Real Power capability; 2) notified the Transmission Planner of the verification; 3) created a process to ensure the Subject Matter Expert and compliance staff are in agreement with future implementation deadlines; 4) created tasks to review the SERC FAQ process during implementation date verification; 5) performed training, with signoffs, on the new process; and 6) added verifications to the maintenance schedule and compliance calendar.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021400	MOD-025-2	R2	Cube Hydro Carolinas, LLC (Cube)	NCR01169	07/01/2016	11/27/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On April 19, 2019, Cube submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R2. Cube failed to provide its Transmission Planner (TP) with verification of the Reactive Power capability of its applicable Facilities in accordance with the NERC Implementation Plan. On March 2, 2019, Cube discovered the noncompliance as part of a review of Implementation Plans. As of July 1, 2018, the Implementation Plan for MOD-025-2 stated that 80% of applicable facilities needed to be compliant. On that date, Cube had completed 0% of coordination activities. On November 26, 2018, Cube performed Reactive Power capability tests on all applicable units and on November 27, 2018, Cube submitted the Reactive Power capability results to its TP. Cube misinterpreted the NERC Implementation Plan to have two phases over the five year period. Specifically, Cube believed that it was required to be 50% compliant on January 1, 2019 and 100% compliant on July 1, 2020. This noncompliance started on July 1, 2016, when Cube failed to submit Reactive Power verification to its TP and ended on November 27, 2018, when Cube finished Reactive Power verification and submitted the results to its TP. The cause of the noncompliance was a lack of effective internal controls to correctly interpret NERC Standards and their effective dates and Implementation Plan. Cube misinterpreted the Implementation Dates and had no control to verify and/or flag the mistake.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Cube's failure to submit generation data to its TP could have led to inaccurate planning models, which in turn could have caused incorrect resource adequacy studies and interconnection studies. Cube has four applicable facilities subject to MOD-025-2. Cube's total nameplate rating for applicable generators is approximately 160 MVA (0.05% of generation in the SERC Region) which limits the exposure. No harm is known to have occurred. SERC considered Cube's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Cube: 1) performed verification of Reactive Power capability; 2) notified the Transmission Planner of the verification; 3) created a process to ensure the Subject Matter Expert and compliance staff are in agreement with future implementation deadlines; 4) created tasks to review the SERC FAQ process during implementation date verification; 5) performed training, with signoffs, on the new process; and 6) added verifications to the maintenance schedule and compliance calendar.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021672	EOP-004-3	R2	Doswell Limited Partnership's (Doswell)	NCR11193	08/15/2018	08/17/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 11, 2019, Doswell submitted a Self-Report stating that, as a Generator Owner and Generator Operator, it was in noncompliance with EOP-004-3 R2. Doswell failed to report events per its Operating Plan within 24 hours of recognition of reportable events. On Tuesday, August 14, 2018 at approximately 9:00 p.m., Doswell personnel discovered an inactive drone on plant grounds while performing routine rounds. The drone was equipped with a high definition camera. Doswell personnel removed the SIM card from the camera, scanned it for viruses, and reviewed the content for reporting events. Doswell discovered that the drone camera recorded 26 general area photos and four videos, some of which focused on the Doswell site from a very high altitude. On August 15, 2018 at approximately 10:45 a.m. plant management notified local law enforcement of the drone. The deputy arrived on site at 11:45 a.m. On August 17, 2018 at 12:56 p.m., Doswell submitted the OE-417 report to the DOE and NERC, which was approximately 40 hours after the 24 hour report submission requirement deadline. Law enforcement identified the owner and the reason for the use of the drone and notified Doswell. Doswell determined the owner and use of the drone to be harmless within 48 hours of Doswell personnel finding the drone at the Facility. The drone belonged to a family that owned property proximate to the site. The family was using the drone to take photos and videos to facilitate discussions with a utility interested in leasing the family's land for possible construction of a solar generation facility. This noncompliance started on August 15, 2018 at approximately 9:00 p.m., when Doswell was required to have reported the drone incident, and ended on August 17, 2018 at 12:56 p.m., when Doswell submitted the OE-417 report of the drone incident to the DOE and NERC. The root cause of this noncompliance was inadequate training. Doswell's operations personnel did not recognize the drone as a "suspicious device or activity at the facility" incident as a potential EOP-004 Reportable Event.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. EOP-004-3 R2 requires the reporting of events after the event occurs and does not relate to actions taken to control the system on a real-time basis. Failure to report events may prevent reliability improvements through adequate event assessment. However, Doswell correctly assessed and reported the occurrence to law enforcement. Furthermore, upon discovery of the device, Doswell determined that the drone posed no immediate physical danger or threat to the facility. The Doswell Facility includes nine units with a total of 1,465 nameplate MVA located in the PJM Balancing Area. The combined net capacity factor for the 12 month period ending April 30, 2019 is approximately 48%. No harm is known to have occurred. SERC considered Doswell's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Doswell: 1) submitted the OE-417 report to the DOE and NERC; 2) developed a specific training module for events reporting; and 3) trained applicable personnel on events reporting requirements.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017018419	PRC-005-6	R3	Duke Energy Carolinas, LLC (DEC)	NCR01219	09/01/2016	01/12/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 29, 2017, Duke Energy Carolinas LLC (DEC) submitted a Self-Report stating that, as a Transmission Owner, it was in noncompliance with PRC-005-6 R3. DEC did not perform required maintenance on a protection system battery. On April 19, 2016, a Contractor Battery Technician performed initial battery testing as part of the commissioning process for the new switchyard, Buck Steam Station. The Contractor Battery Technician completed computerized documentation of that testing, but did not submit a battery and charger asset report (BCAR) to DEC. The BCAR would have transferred maintenance responsibility to DEC. However, because of the failure to submit the BCAR, DEC did not enter the new battery asset into its Protection System Maintenance Program Database so that future testing and maintenance could be scheduled. On January 11, 2017, a Contract Substation Technician, that performed quarterly battery inspection, called a DEC Battery Technician to ask if the Substation Technician should be performing quarterly battery inspections on the new battery/charger at the new Buck Steam Station. Subsequently, the DEC Battery Technician contacted the Compliance Analyst with the question and discovered that DEC failed to perform two of the 4-calendar-month battery checks on the new battery. This noncompliance started on September 1, 2016, the day DEC should have performed battery maintenance, and ended on January 12, 2017, when DEC performed the required maintenance activity. The root cause of this noncompliance was a lack of internal control.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Failure to maintain protection system batteries could have resulted in failure of the protection system to operate, when needed, resulting in damage to Facilities. However, the Buck Steam Station is a 100 kV station used to interconnect five dual circuit lines and four radials to load. Any problems at this station would have been limited in scope to a small portion of DEC's 100 kV system. In this case, the battery was a new battery that was properly operating at the completion of initial testing. DEC missed only two of the 4-month maintenance intervals. Had the battery voltage been lost or was too low, the microprocessor relays would have detected the problem and alerted operators. The station does have a battery alarm that tested well on January 12, 2017 and DEC's control center would have received any battery or charger alarm. No switching misoperations occurred during the issue. No harm is known to have occurred. SERC determined that DEC's compliance history with PRC-005 should not serve as a basis for applying a penalty. The underlying cause of the prior and instant noncompliance is different. Thus, the mitigation for the prior noncompliance could not have prevented the instant noncompliance. SERC reviewed the noncompliance history with PRC-005 for DEC's affiliates, Duke Energy Corporation (DECorp), Duke Energy Progress (DEP), and Duke Energy Florida (DEF) and did not identify circumstances similar to that of the instant issue. Each Duke Energy affiliate is responsible for its own maintenance and testing program and the completed mitigation plans could not have prevented the instant noncompliance.
Mitigation	To mitigate this noncompliance, DEC: 1) tested the Buck Battery and Charger; 2) performed the required 4-month inspection; 3) added the Buck Battery and Charger to the work management system for Annual and Quarterly Inspection preventative maintenance; 4) facilitated a compliance stand-down with DEC technicians to re-enforce expectations of documentation and to review the event that was discovered by this noncompliance; and 5) assigned, by the DEC P&C Engineering, a minimum of two point of contacts, with joint responsibility, for projects that require Battery & Charger protection and controls engineering review.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017018550	PRC-005-1.1b	R2	Duke Energy Carolinas, LLC (DEC)	NCR01219	07/01/2014	07/13/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 30, 2017, Duke Energy Carolinas, LLC (DEC) submitted a Self-Report stating that, as a Transmission Owner, it was in noncompliance with PRC-005-1.1b R2. DEC reported that it had not maintained two Protection System relays in accordance with its Protection System Maintenance Program (PSMP) that established a three-year maintenance and testing interval for these devices. In 2007, a Relay Technician disabled one function of two relays located at the Oliver Black and Oliver White 230kV lines at Marshall Steam Station Switchyard, but the other functions remained in service. The Relay Technician incorrectly marked the front nameplate on both relays as 'blocked', which indicated that the relays were out of service. The 'blocked' status of the relays was not changed in the database for the scheduled maintenance and testing in accordance with the PSMP. Therefore, the relays were tested in 2010. On December 1, 2010, as a result of a DEC system-wide verification that the actual operating status of each protective device matched the database values of the relays, DEC changed the database to JB(1), which indicated the relays were out of service, to match the labels of the relays. On July 11, 2017, a Construction, Maintenance & Vegetation (CMV) Compliance Analyst received an email notification from Aspen Administrator Protection & Controls (P&C) Engineering. The email informed the CMV Compliance Analyst that the Administrator had been working with a Relay Technician concerning two 21L3R relays on the Oliver Black and Oliver White lines. The Relay Technician indicated that, while writing trip path testing procedures, it discovered that the 21L3R relays were marked as 'blocked' and were 'JB' status in the database of the relays. However, the relays were still in service and provided an input to start the on/off carrier, which provided a blocking function during certain fault conditions. DEC had not performed maintenance on the Oliver Black and Oliver White 21L3R relays since 2010. As a result, DEC missed two intervals per relay. This noncompliance started on July 1, 2014, when DEC was required to have performed maintenance on the relays in accordance with its PSMP, and ended on July 13, 2017, when DEC performed the required maintenance. The root cause of this noncompliance was a procedural deficiency. The tagging process did not clearly define the conditions required to determine out-of-service relays so they can be tagged as blocked.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). Failure to perform Protection System Maintenance could cause unnecessary trips or prevent adequate protection of elements of the BPS. However, in this instance, the potential risk to the BPS was minimal because the relays 21L3R will operate a carrier signal that would delay instantaneous tripping on the remote end of the transmission line for certain faults. Failure to operate as designed would result in a system misoperation under certain circumstances. In addition, the system topology in this area has several interconnection tie lines that could support the loss of the transmission line. The overtrip of one line for a fault on another line would not cause excessive weakness to the BPS. The noncompliance did not result in misoperations, emergencies, or other adverse consequences. No harm is known to have occurred. SERC determined that DEC's compliance history with PRC-005 should not serve as a basis for applying a penalty. However, the underlying cause of the prior and instant noncompliance is different. Thus, the mitigation for the prior noncompliance could not have prevented the instant noncompliance. SERC reviewed the noncompliance history with PRC-005 for DEC's affiliates, Duke Energy Corporation (DECorp), Duke Energy Progress (DEP), and Duke Energy Florida (DEF) and did not identify circumstances similar to that of the instant issue. Each Duke Energy affiliate is responsible for its own maintenance and testing program and the completed mitigation plans could not have prevented the instant noncompliance.
Mitigation	To mitigate this noncompliance, DEC: 1) updated Aspen Relay Database to reflect that the relays are "in service"; 2) performed Preventative Maintenance on the relays; 3) updated One Line and design drawings to reflect the installed status of the relays; 4) revised, trained, and implemented the tagging process to include guidance which clearly communicates conditions required in order to determine a relay is out-of-service and is acceptable to be tagged as blocked; and 5) developed and deployed a process, which more clearly communicates Relay Settings changes from DEC P&C Settings Engineers to DEC CMV Relay Technicians.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017018825	TOP-001-3	R13	Duke Energy Carolinas, LLC (DEC)	NCR01219	10/03/2017	10/03/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 15, 2017, per an existing multi-regional registered entity agreement, Duke Energy Carolinas (DEC) submitted a Self-Report, on behalf of Duke Energy Corporation, LLC (DECorp) (NCR00761), stating that, as a Transmission Operator (TOP), DECorp was in noncompliance with TOP-001 R13. DECorp did not ensure that a Real-time Assessment (RTA) was performed every 30 minutes. On October 3, 2017, at approximately 2:02 a.m., DECorp Real Time Contingency Analysis (RTCA) application performed a valid solution on the Energy Management System (EMS) at DECorp's Plainfield Energy Control Center (ECC). Between 2:02 a.m. and 2:59 a.m., the primary RTCA application failed to return a valid solution. The problem was discovered when a System Operator received an unknown alarm, and proceeded to utilize a checklist designed to determine if the EMS successfully "restarted" after failing over to a different server. The DeCorp's Reliability Coordinator (RC) was contacted to perform backup RTCA at 2:53 a.m. The primary RTCA application was returned to service at 2:59 a.m. EST. This resulted in a failure of DECorp to perform a RTA at least every 30 minutes, as required by TOP-001-3 R13. This noncompliance started on October 3, 2017, at 2:32 a.m., when DECorp was required to have ensured completion of a RTA, and ended on October 3, 2017, at 2:53 a.m., when DECorp notified its RC to ensure that it performed an RTA. The root causes of this noncompliance were an ineffective internal control and a procedural deficiency. The EMS alarm was not specific enough to identify the loss of RTCA and the procedure the System Operator followed did not have a section for addressing RTCA failures greater than 30 minutes.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Failure to ensure that a RTA is completed may result in instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Interconnection. However, this noncompliance occurred during the early morning hours when the system is relatively stable. The noncompliance lasted only 43 minutes and DECorp continued to have alarms and indications for its transmission area during that time. No contingencies occurred during the noncompliance. No harm is known to have occurred. SERC considered DECorp's, and its affiliates, DEC, Duke Energy Florida, and Duke Energy Progress', compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, DECorp: 1) notified its RC that RTCA was not solving and asked the RC to monitor for contingencies and notified Plainfield ECC on any issues; 2) had EMS Support manually restart RTNET, RTCA, and OLNETSEQ; 3) added and discussed the addition of a "NETWORK SEQUENCE DOES NOT COMPLETE WITHIN PERIOD" alarm to the EMS point description display with Midwest Control Area Operations (MCAO), Cincinnati, and Plainfield ECC System Operators; 4) revised its Security Applications Failure procedure to include assigned tasks when RTCA failures exceed 30 minutes; 5) reviewed all Duke Energy Registered Entity procedures and confirmed they address assigned tasks when RTCA failures exceed 30 minutes; 6) completed the investigation with the vendor regarding the cause of Real-Time Network Sequence failure; and 7) trained MCAO, Cincinnati, and Plainfield ECC System Operators on changes to Security Apps Failure procedure.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017018833	PRC-005-1b	R2	Duke Energy Carolinas, LLC (DEC)	NCR01219	01/01/2013	11/30/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 19, 2017, Duke Energy Carolinas (DEC) submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-005-1b R2. DEC reported that it had not maintained Protection System relays in accordance with its Protection System Maintenance Program (PSMP). On October 4, 2017, DEC performed a review of its nuclear power plants to verify that all Protection System devices met the maintenance and testing requirements of PRC-005-6. DEC reviewed Keowee because it consists of two 80 MW hydropower generating units that sometimes operate independently on the grid as a hydro power resource, but also provides a safety power supply to the Oconee Nuclear Station. During this review, DEC Technicians identified two undervoltage initiating relays in the Keowee Generator Protection System that DEC had failed to maintain since 2008. Under the PSMP, the relays required maintenance every four years; therefore, maintenance should have been performed in 2012. DEC performed an extent-of-condition evaluation for all Oconee U1, U2, and U3, and Keowee U1 and U2 NERC related equipment for similar mislabeling issues. DEC found no additional issues and did not expand the evaluation. This noncompliance started on January 1, 2013, when DEC should have performed relay maintenance in accordance with its PSMP, and ended on November 30, 2017, when DEC correctly identified the relays and completed the required relay maintenance. The cause of this noncompliance was the Entity's failure to label two relays in accordance with the Institute of Electrical and Electronics Engineers (IEEE) Standards for device numbers, thus inadvertently misidentifying the relays as an incorrect type of relay. For instance, the relays were incorrectly labeled 74GV1 and 74GV2 instead of 27GV1 and 27GV2. The numbers 74 indicated that they were alarm relays instead of undervoltage relays. The incorrect name implied PRC-005 did not apply to these relays and allowed DEC to incorporate a process to defer the work in 2008 and 2012.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). DEC's failure to properly maintain the undervoltage relays could have caused an inadvertent trip or prevented the trip of the Keowee units. The Keowee units are small 80 MW hydro units that are usually dedicated to the backup power needs of Oconee Nuclear Station; thus, even had the units tripped due to missed relay maintenance, it would have had minimal impact to the BPS. Notwithstanding, the units are fully redundant and it is highly unlikely that both relays would have failed in the same way simultaneously. When DEC tested the relays, DEC found the relay calibration to be accurate leading to the conclusion that a setpoint drift that could have affected reliability was also highly unlikely. No harm is known to have occurred. SERC determined that DEC's compliance history with PRC-005 should not serve as a basis for applying a penalty. DEC's prior noncompliance was a 2010 issue, and the underlying cause of the prior and instant noncompliance is different. Thus, the mitigation for the prior noncompliance could not have prevented the instant noncompliance. SERC reviewed the noncompliance history with PRC-005 for DEC's affiliates, Duke Energy Corporation (DECorp), Duke Energy Progress (DEP), and Duke Energy Florida (DEF) and did not identify circumstances similar to that of the instant issue. Each Duke Energy affiliate is responsible for its own maintenance and testing program and the completed mitigation plans could not have prevented the instant noncompliance.
Mitigation	To mitigate this noncompliance, the DEC: 1) relabeled the relays to correctly identify them as undervoltage relays; 2) performed relay preventive maintenance; and 3) renewed relay preventative maintenance to a four-year interval.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2016016094	PRC-005-2(i)	R3	Duke Energy Carolinas, LLC (DEC)	NCR01219	07/01/2016	06/16/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 1, 2016, Duke Energy Carolinas, LLC (DEC) submitted a Self-Report stating that, as a Transmission Owner (TO), it was in noncompliance with PRC-005-2(i) R3. DEC did not maintain certain Protection System Devices in accordance with PRC-005-2(i). Per PRC-005-2 R3, DEC is obligated to maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. Before the implementation of PRC-005-2(i), DEC operated a number of dual circuit 115 kV transmission lines as radial systems serving load, which did not fall under the definition of Bulk Electric System (BES). As non-BES devices, they received only periodic maintenance testing. Following the implementation of the revised definition of BES, DEC's Transmission Planning opted to reconsider the dual circuit 115 kV transmission lines as distribution networks (Local Networks), for planning purposes, rather than radial systems serving load. As such, the Local Networks were classified as BES Facilities under the revised definition. On July 1, 2016, twenty-four months following the effective date of the definition, under the implementation plan for Phase 2 of the revised BES definition, compliance obligations for newly identified BES devices began, however, DEC had not revisited those dual circuits to determine if its maintenance practices aligned with PRC-005-2(i). In the spring of 2016, DEC discovered that although the Marble Hill Tie was compliant, DEC had not changed the non-BES designation to BES at the Marble Hill facility and several other facilities. On July 11, 2016, DEC identified that it had not maintained and tested the Protection System Battery at Perkins Tie in accordance with PRC-005-2. DEC determined the battery maintenance to be the only noncompliance at Perkins Tie. DEC conducted an extent-of-condition of its entire transmission system to determine the scope of the noncompliance. DEC identified 14 relays and two batteries that it did not test and maintain within the defined intervals due to the misclassification as non-BES devices. This noncompliance started on July 1, 2016, when compliance related to the revised definition of the BES became enforceable, and ended on June 16, 2017, when DEC designated the non-BES Facilities as BES Facilities and performed the required time-based maintenance intervals prescribed by the standard. The root cause of this noncompliance was the lack of a documented process for the identification of BES assets and equipment. As a result, DEC failed to follow up on its intent to revisit the dual circuits to determine the appropriate designation, which led to DEC's failure to perform the required time-based maintenance intervals prescribed by the standard.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Failure to properly maintain Protection System devices could result in failure to respond to system faults resulting in misoperations and other unnecessary Protection System responses and equipment damage. However, in this case, all of the noncompliance occurred on 100 kV systems that DEC previously considered to be radial systems serving load and would not have caused disturbances at the larger network. In each case, DEC performed maintenance activities within one year of the required interval and found no discrepancies when it performed maintenance and testing. No misoperations occurred. No harm is known to have occurred. SERC considered DEC's PRC-005-1 compliance history in determining the disposition track. DEC's relevant prior noncompliance with PRC-005-1 R2 includes: NERC Violation ID SERC201000544. SERC determined that DEC's compliance history should not serve as a basis for applying a penalty. In SERC201000544, DEC did not test approximately 1.9% of its devices within the defined interval. The instant violation involved missed intervals, but related to the implementation of PRC-005-2, not the assigned intervals of PRC-005-1. The mitigation plan for SERC201000544 did not address and could not have prevented the instant issue. SERC reviewed the posted violations of PRC-005 for affiliates of DEC, Duke Energy Corporation (DECorp), Duke Energy Progress (DEP), and Duke Energy Florida (DEF) and did not identify circumstances similar to that of the instant issue. Each Duke Energy affiliate is responsible for its own maintenance and testing program and the completed mitigation plans would not have addressed the instant issue. Therefore, SERC staff did not consider the previous violations by affiliates as aggravating circumstances.
Mitigation	To mitigate this noncompliance, DEC: 1) revisited the Marble Tie Apparent Cause Analysis to identify additional mitigating activities addressed in steps 5-9; 2) performed the maintenance and testing on misclassified BES elements; 3) developed a process to include the appropriate Business Units on new projects during the installation of new equipment and substations for the identification of BES assets and equipment; 4) assigned appropriate workgroup ownership and governance for the creation, implementation, maintenance, and communication of identified BES Facilities, as identified by Transmission Planning across all Duke Energy Regions, which includes the verification of Local Networks; and 5) reviewed the color coded BES maps of all DEC lines and substations;

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2016016094	PRC-005-2(i)	R3	Duke Energy Carolinas, LLC (DEC)	NCR01219	07/01/2016	06/16/2017	Self-Report	Completed

	6) ensured that proper equipment and maintenance databases were updated with the proper NERC flagging; 7) held a meeting to discuss BES checklist processes and forms; 8) published an updated BES checklist; and 9) developed and delivered computer based training (CBT) training.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2016016139	PRC-005-2(i)	R3	Duke Energy Carolinas, LLC (DEC)	NCR01219	08/31/2015	02/26/2016	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 6, 2016, SERC sent Duke Energy Carolinas, LLC (DEC) an audit notification letter notifying it of a Compliance Audit scheduled for September 6, 2016 through December 16, 2016. On September 13, 2016, DEC submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-005-2(i) R3. DEC discovered multiple instances where it failed to perform time-based battery maintenance in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. On February 5, 2016, during pre-audit documentation reviews, DEC found that the work orders for quarterly battery maintenance checks at Belew's Creek Units 1 and 2 did not include records of battery electrolyte levels for the third quarter of 2015. DEC performed an extent-of-condition and discovered additional instances. DEC missed its fourth quarter 2015 battery maintenance interval at Cliffside by eight days. DEC also discovered that it did not schedule maintenance in the third quarter of 2015 for Bad Creek Hydro, Cowan's Ford Hydro, Fishing Creek Hydro, Jocassee Hydro, Nantahala Hydro, Oxford Hydro, and Wateree Hydro. Quarterly and annual work orders had been in place to support compliance with PRC-005-1, but, in the course of making changes to the fleet-wide battery maintenance program, there was confusion regarding quarterly requirements versus annual requirements, and the work crew failed to generate work orders for the third quarter of 2015. Affiliates of DEC also performed a review of battery records and found no additional occurrences. This noncompliance started on August 31, 2015, when quarterly battery checks at the plant site, Belew's Creek, should have included checking battery electrolyte levels, and ended on February 26, 2016, when DEC performed the latest required battery maintenance at the Cliffside plant site. The root causes of the noncompliance was a procedural deficiency and lack of training. The work orders used to schedule maintenance did not include all the required time-based maintenance activities, which created confusion as to the appropriate testing and maintenance intervals. Additionally, training was lacking on the expectations of what information was needed to complete the work orders.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Failure to properly maintain power plant batteries could result in the failure to protect the generator in the event of a fault. The noncompliance involved nine plant sites and 17 associated batteries. The plants represented 6,043 MWs, or 26.9% of 22,500 MWs, of generation in DEC. However, the actual risk to the BPS was minimal because the batteries were in compliance with PRC-005-1 when the issue started. During previous testing by DEC, all batteries exhibited greater than 100% design capacity. All affected batteries have alarms to alert an operator to low voltage conditions and roving operators check the physical condition of the batteries at least weekly. DEC completed the additional requirements imposed by PRC-005-2 during the next maintenance interval and found no concerns. There were no misoperations, emergencies, or other adverse consequences to the BPS as a result of this issue. No harm is known to have occurred. DEC does have a prior noncompliance with PRC-005. However, the prior noncompliance was related to a prior version of the standard (PRC-005-1); the instant noncompliance was related to the implementation of PRC-005-2. The mitigation plan for DEC's prior noncompliance could not have prevented the instant issue. Additionally, there were prior noncompliances of PRC-005 for affiliates of DEC, including Duke Energy Progress and Duke Energy Florida, but the underlying causes between the instant and prior noncompliances is different, and each Duke Energy affiliate is responsible for its own maintenance and testing program and the completed mitigation plans would not have addressed or prevented the instant issue.
Mitigation	To mitigate this noncompliance, DEC: 1) revised work orders to include all the required time based maintenance activities; 2) monitored completions of the above activities within the required time frame; 3) reviewed verification of each Duke Energy BES station time based maintenance records for completeness and timeliness for each battery maintenance interval for the year 2016-2017; and 4) developed and delivered a mandatory computer based training (CBT) course on the Fossil Hydro Station Battery Maintenance Program, with primary emphasis on NERC requirements. CBT will be required at on-boarding and annually, and will be applicable for Fossil-Hydro operation, maintenance, and engineering personnel that are located at or support Generating stations. The training will be performed across the Duke Enterprise.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017017993	PRC-024-2	R1	Duke Energy Carolinas, LLC (DEC)	NCR01219	07/01/2016	03/29/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 21, 2017, Duke Energy Corporation (DECorp) submitted a Self-Report stating that, as Generator Owner (GO), it was in noncompliance with PRC-024-2 R1. Also on that date, Duke Energy Progress, LLC (DEP), Duke Energy Florida, LLC (DEF), and Duke Energy Carolinas, LLC (DEC) submitted Self-Reports, with tracking numbers SERC2017017998, SERC2017017999, and SERC2017017995, respectively, making the same assertion. DEC, DEP, DEF, and DECorp are subject to a multi-regional registered entity (MRRE) agreement and, as such, SERC rolled the Self-Reports for DEP, DEF, and DEC into the instant Self-Report. Hereafter, this document refers to all four affiliates, collectively, as the Entities. Prior to July 1, 2016, the Corporate Compliance Group, who represented the Entities, developed a plan of action to meet the NERC Implementation Plan of PRC-024-2 R1. In accordance with the Corporate Compliance Group's plan, each Entity believed that it had completed all of the verification of devices required to meet the implementation milestone of its applicable facilities. However, the Corporate Compliance Group interpreted the requirement to exclude generator trips associated with the generator excitation systems. Therefore, the Entities failed to verify the generator trips associated with generator excitation systems testing, which, is a necessary and needed component of compliance of PRC-024-2 R1. On July 1, 2016, the Entities had 0 percent compliance with PRC-024-2 R1. On December 14, 2016, NERC discussed the scope of PRC-005-6 and published its interpretation that NERC's definition of Protection Systems included generator trips associated with generator excitation systems. On December 29, 2016, testing was completed to bring the Entities back into compliance with the NERC Implementation Plan. This testing came as a direct result of the aforementioned NERC meeting. No setting changes were required due to the testing. On July 1, 2017, DEC and DECorp had at least 60 percent of its facilities compliant, which met the milestone of the NERC Implementation Plan. DEP had 55 percent of its facilities compliant, which failed to meet the milestone. DEP believed it had 45 of 72 units in compliance, when it only had 40 units in compliance. DEF had 55 percent of its facilities compliant, which failed to meet the milestone. DEF believed it had 36 of 60 units in compliance, when it only had 33 units in compliance. On August 30, 2017, DEP discovered that five units at H.F Lee and Sutton, which DEP counted in its 60 percent milestone, were actually in noncompliance. After testing, no setting changes were required. On October 2, 2017, DEF discovered that three units at Hines, which DEF counted in their 60 percent milestone, were actually in noncompliance. After testing, DEF had to make three setting changes. Hines CC – CT3A and Hines CC – CT3B required changes at 58.8 Hz and 58 Hz, setting the minimum delay from 10 to 33 seconds and one to five seconds, respectively. Hines CC – ST3 required changes at less than 58.5 HZ and greater than 61.5 Hz, setting the minimum delay from 10 to 33 seconds and 10 to 21 seconds, respectively. On January 18, 2018, DEP and DEF submitted an expansion of scope stating its continued noncompliance with the NERC Implementation Plan of PRC-024-2 R1. On March 29, 2018, DEF implemented the setting changes for the three units and returned to compliance. This noncompliance had two periods. The first period started on July 1, 2016, when the Entities should have verified the setpoints of at least 40 percent of its generators, and ended on December 29, 2016, when the Entities completed verification for 40 percent of its facilities. The second period started on July 1, 2017, when DEP and DEF failed to verify the set points on 60 percent of its generators and ended on March 29, 2018, when DEF implemented the necessary setting changes. The root cause was a misinterpretation of the requirements of PRC-024-2. Specifically, the Entities failed to identify that the requirement included generator trips associated with the generator excitation systems.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The Entities' failure to properly verify the frequency protection setpoints could result in generators unnecessarily tripping off-line during frequency transients. Outside of the generator excitation systems, all testing was completed within the appropriate timeframe. Additionally, the eight total units that were out of compliance on 7/1/2017 put DEF and DEP out of compliance by only 5 percent each. Those units' output make up a small portion of the Entities' total output. No harm is known to have occurred. SERC considered the Entities' compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the Entities: 1. performed evaluation of protective functions in excitation systems with applicability in Protection Systems; 2. pulled PRC-024 documentation used to achieve 40 percent milestone on 7/1/2016 for reevaluation and modified PRC-024 review scope and program philosophy to require studies to incorporate protective functions in the excitation systems, which required revision of existing studies and new studies to include the voltage and frequency protective functions in the excitation systems; 3. added excitation Protection System functions to applicable coordination studies and Duke Energy Fossil-Hydro and Nuclear Generation met the 60 percent milestone in all regions by 7/1/2017;

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SERC2017017993	PRC-024-2	R1	Duke Energy Carolinas, LLC (DEC)	NCR01219	07/01/2016	03/29/2018	Self-Report	Completed

4. evaluated other NERC Reliability Standards to determine if inclusion of protective functions in excitation systems affected associated programs, procedures, processes used for compliance;
5. trained on Request for Interpretation process for escalations to NERC;
6. modified associated programs, procedures, and associated processes to incorporate protective functions in excitation systems;
7. communicated to FHO personnel responsible for developing and reviewing PRC-024 documentation the need to include voltage and frequency protective functions in control systems, e.g. Excitation System, in the scope of PRC-024 protective relay setting evaluations; and
8. implemented a compliance program checkpoint/Quality Assurance review to:
   (i) evaluate new processes and programs prior to implementation,
   (ii) evaluate the program against the Requirements and Measures of the NERC Reliability Standard,
   (iii) document any program bases and incorporated interpretations, and
   poll other utilities for common interpretation when there is no internal consensus. If affiliates cannot reach consensus, the Quality Assurance Process document will require the Entities to utilize established processes to request interpretation from NERC when necessary.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017018838	VAR-002-1.1b	R1	Entergy - Fossil & Hydroelectric Generation (EntergyFHG)	NCR11167	09/09/2011	05/17/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On November 28, 2017, EntergyFHG submitted a Self-Report stating that, as a Generator Operator (GOP), it was in noncompliance with VAR-002-1.1b R1. EntergyFHG did not operate certain automatic voltage regulators (AVR) in automatic controlling voltage. On May 4, 2017, while performing testing, pursuant to compliance with MOD-025-2, operators of Carpenter Dam Unit 1 discovered that the generator output control system included a programmable logic controller (PLC) that override the controlling action of the AVR. The PLC controlled the generator reactive output to zero plus or minus 5 MVAR. EntergyFHG did operate the Carpenter Dam 1 AVR in automatic controlling voltage. However, EntergyFHG was unaware that the PLC controller override its effect. Carpenter Dam Unit 2 also operated in automatic controlling voltage and did not have a PLC controller. A review of the Plantview NERC Compliance log identified two occasions associated with Carpenter Dam voltage excursions during October 1, 2015 to December 31, 2017. During both excursions, the operator followed the reporting requirements to notify the TOP. Plant personnel did not identify the need for disabling the PLC when it developed and implemented EF-PR-NERC-04, its procedure to verify operational, compliance, and subsequent related procedures. EntergyFHG executed an extent-of-condition review (EOC) to determine if other units that it operates could also be in noncompliance with VAR-002-1.1b R1. It discovered it operated AVRs for all three units at Remmel Dam in automatic control but controlling VARS rather than voltage. EntergyFHG installed new AVRs at Remmel Dam in 2010. Engineering documentation related to the change established VAR control as the preferred mode of control and EntergyFHG did not observe that to be a noncompliance until performance of the EOC. The rating for each unit at Remmel Dam is 4.12 MVA, less than the threshold to be classified as a Bulk Electric System (BES) element, but EntergyFHG's TOP lists all three units as blackstart resources, which brings them under the definition of BES. For that reason, they are subject to compliance with VAR-002-1.1b and later versions. A review of the Plantview NERC Compliance log identified two occasions associated with Remmel voltage excursions between October 1, 2015 and December 31, 2017. During both excursions, the operator notified the TOP in accordance with its procedures. The review confirmed EntergyFHG operated all other units with the AVR in the mode specified by the TOP (automatic voltage control). SERC determined that EntergyFHG was in noncompliance with VAR-002-1.1b R1 and its successors because it did not operate the AVR of generators connected to the BES in automatic controlling voltage. This noncompliance started on September 9, 2011, when EntergyFHG registered as a GOP, and ended on May 17, 2018, when EntergyFHG removed the PLC controller from Carpenter Dam unit 1 and placed all AVRs at Remmel Dam in voltage control. The root cause was insufficient training. Plant personnel did not identify the need to remove the equipment that conflicted with the AVR, specifically, the PLC, and the Transmission Operator did not provide an exemption to operate in a mode other than voltage control. Entergy FHG has since revised its procedures to document the distinction between VAR regulation and Voltage regulation.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Operation of AVRs in modes other than automatic controlling voltage could result in undesirable and unexpected responses during voltage disturbances. However, this noncompliance occurred at small hydro generation units that operate with a capacity factor of approximately 25%. Remmel and Carpenter Dam operators did notify the TOP when unit output voltages exceeded the assigned voltage schedule. No other voltage-related events occurred on the Entergy system. No harm is known to have occurred. SERC determined that EntergyFHG's compliance history should not serve as a basis for applying a penalty. The prior noncompliance dealt with legacy issues and mitigation for the prior noncompliance could not have prevented the instant noncompliance.
Mitigation	To mitigate the noncompliance, EntergyFHG: 1) disabled the PLC that overrode the controlling action of the AVR for Carpenter Dam Unit 1; 2) placed the Remmel AVRs in automatic controlling voltage, but as a long-term correction, the TOP revised its operating procedure to include additional details regarding reactive power schedule for all Remmel units, allowing the AVRs to operate in VAR control mode; 3) trained applicable TOP personnel on the revised operating procedure; and 4) conducted lessons learned training with all Entergy FHG NERC Champions, which was included in EntergyFHG's reporting system and remains available for future reference.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2016016659	PRC-005-1.1b	R2, R2.1, R2.2	Georgia Power Company (GPC)	NCR01247	06/25/2014	05/06/2016	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 15, 2016, Georgia Power Company (GPC) submitted a Self-Report stating that, as a Transmission Owner (TO), it was in noncompliance with PRC-005.1.1b R2. GPC did not test and maintain seven batteries in accordance with its Protection System Maintenance and Testing Program. On January 25, 2016, in SERC2016015486, GPC self-reported a battery noncompliance at the Plant Hammond Transmission Facility. Through the mitigating activities for this noncompliance, GPC discovered and self-reported seven additional instances of noncompliance involving the following seven transmission facilities: Statesboro Primary, Truman Parkway, Rome, Cabin Creek, Patsiliga Creek, Rustin Lake, and Victory Drive. In the first instance, on March 7, 2016, GPC discovered that in March 2015, GPC installed a new battery at the Statesboro Primary Transmission Facility but did not perform the commissioning tests or any other subsequent required maintenance and testing activities. Neither the contractor that installed the battery, nor GPC's Transmission Line Design Group that ordered the battery, communicated the installation to the Transmission Maintenance Center (TMC). Therefore, the TMC did not enter the battery in the Standard Transmission Operation and Maintenance Program (STOMP) so that future maintenance and testing could be scheduled. In the second instance, on April 4, 2016, while preparing for the installation of a temporary capacitor bank, the Transmission Supervisor received a question from the field about the SERC code classification of the Truman Parkway Substation. After reviewing the facility, GPC discovered that during the commissioning process, Transmission Maintenance Support should have changed the SERC code from a distribution substation to a transmission substation due to the addition of 115kV breakers in May 2015. This change in the SERC code would have changed the battery maintenance interval from every six months, under the GPC program, to every four months, as required by the Standard. In the third instance, on April 4, 2016, GPC put into service a new substation, Cabin Creek, with a 115 kV breaker to serve as a point of interconnection for a non-BES biomass generator. The substation went into service on April 4, 2016, but the battery commissioning tests weren't completed until April 12, 2016 because the substation was incorrectly coded. In the fourth instance, on April 12, 2016, GPC determined that it did not complete the commissioning test of the battery at the Rome Substation following a capital project. The TMC and Protection and Control Field Services completed the installation of a new control house associated with a station rebuild and relay upgrade. The TMC installed the battery fuses and followed business practices by allowing them to sit on charge, which must be continuous for 72 hours, in preparation for the upcoming battery commissioning. However, the TMC crew foreman did not create a work order, which resulted in the crew not going back to perform the battery commissioning testing. In the fifth, sixth, and seventh instances, on May 5, 2016, a Transmission Compliance Engineer discovered that GPC installed new batteries at Patsiliga Creek, Rustin Lake, and Victory Drive substations as part of a capital project, but failed to perform commissioning tests. GPC initiated the equalizing charge for the batteries, which must be continuous for 72 hours, but failed to complete the capacity tests. This noncompliance for all instances started on June 25, 2014, when, in the seventh instance, GPC failed to conduct required battery test, and ended on May 6, 2016, when, in the fifth and sixth instances, GPC performed the required battery tests. The root cause of these instances was a lack of internal controls to ensure that battery tests were conducted. GPC's STOMP did not include a method for ensuring that work orders were created after installation of batteries to ensure that battery commission tests would be conducted or a validation process for comparing batteries ordered to those identified in the STOMP to serve as a secondary check to ensure batteries were identified for commissioning.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). GPC's failure to conduct testing on batteries could have resulted in the battery not functioning properly and thus impacting the operation of other Protection System Devices. However, GPC had the battery and charger at each location monitored and alarmed via Supervisory Control and Data Acquisition. Personnel in the Georgia Control Center monitor the status of all substation batteries and charging systems 24 hours per day, seven days per week. A problem with the battery would have resulted in an alarm in advance of failure. GPC would have dispatched field personnel to the facility with high priority to identify and correct any problems. In addition, GPC trains field personnel to observe batteries and charging systems, as well as, other equipment as part of routine inspections upon entering any substation. The meter and annunciator trouble lights on the battery charger panel were easily observable by field personnel entering the substation throughout the period of possible non-compliance for each of the locations. All batteries were new batteries,

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SERC2016016659	PRC-005-1.1b	R2, R2.1, R2.2	Georgia Power Company (GPC)	NCR01247	06/25/2014	05/06/2016	Self-Report	Completed

	therefore, the probability of failure is low. None of the transmission substations associated with the noncompliant batteries were included on the CIP-014 Critical Facility List. Therefore, GPC would not have anticipated cascading events if the batteries had failed to perform. No harm is known to have occurred. GPC does have five relevant prior noncompliances with PRC-005. GPC did not identify the instant noncompliance until implementation of mitigation of the most recent prior noncompliance. Both noncompliances would have been processed together had GPC discovered the instant noncompliance earlier. Thus, the mitigation for the prior noncompliance would not have prevented the instant noncompliance. Further, the underlying causes of the instant noncompliance and the remaining four prior noncompliances were different. Thus, the mitigation of these prior noncompliances would not have prevented the instant noncompliance. Moreover, these four noncompliances were issues from 2008 – 2013, which does not demonstrate programmatic failures in GPC STOMP.
Mitigation	To mitigate this noncompliance, GPC: 1) performed commissioning tests on batteries that did not have the tests performed; 2) changed the query utilized for battery reviews to identify stock and non-stock batteries which ensures that GPC identifies all NERC battery sets; 3) provided guidance to stakeholders on the division of responsibilities regarding tasks associated with battery sets to ensure NERC battery sets are commissioned and maintained; 4) revised the STOMP-Lite Battery Report to send notifications for overdue "On Order" battery sets as a notification to ensure batteries are commissioned; 5) reviewed the responsibilities of new battery installations with the GPC Construction Wiring Group to reinforce the communication expectations regarding notification to the TMC after batteries have been installed to ensure commissioning; 6) developed a mobile application to ensure work orders are created after battery sets are installed by the GPC Construction Wiring Group; and 7) developed a battery identification validation process that compares batteries ordered versus those identified in STOMP as a secondary check to ensure batteries are identified for commissioning.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021350	BAL-005-0.2b	R10	LG&E and KU Services Company as agent for Louisville Gas and Electric Company and Kentucky Utilities Company's (LGE and KU)	NCR01223	03/16/2018	09/21/2018	Self-Log	Completed
Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On April 15, 2019, LGE and KU submitted a Self-Log stating that, as a Balancing Authority (BA), it was in noncompliance with BAL-005-0.2 R10. LGE and KU failed to include one Dynamic Schedule in the calculation of Net Scheduled Interchange for the Area Control Error (ACE) equation. LGE and KU serves a substation load from the LGE and KU transmission system. LGE and KU configures the load as a Dynamic Schedule in the ACE calculation for the LGE and KU BA. This is a telemetered load and its value is multiplied by -1 in the Energy Management System (EMS) so that LGE and KU subtracts the load from the Scheduled Interchange value. LGE and KU checks out loads as positive values; however, since this is a dynamic load, LGE and KU assigns a negative value in the EMS so that the flow between the adjacent BA and LGE and KU BA nets to zero. This is the only Dynamic Schedule within the LGE and KU BA. The Dynamic Schedule is included in the Net Schedule Interchange value in the ACE equation. On March 12, 2018, an entity installed a temporary transformer to facilitate work on the metering equipment at the substation. On March 16, 2018, LGE and KU changed the load value from a negative flow to a positive flow. This is telemetered load and LGE and KU receives the data whether or not the substation is in service. On March 18, 2018, the substation returned to service and the substation load entered EMS with a positive value, however, LGE and KU failed to change the multiplier back to -1. As a result, the ACE calculation was offset 6 to 8 MW for the period March 16, 2018 through September 21, 2018 as the load range was 3 to 4 MW. On September 21, 2018, LGE and KU discovered the incorrect multiplier while updating the operator desk documentation as part of a documentation review process. This noncompliance started on March 16, 2018, when LGE and KU changed the load value from a negative flow to a positive flow, and ended on September 21, 2018, when LGE and KU corrected the EMS value multiplier assigned to the load. The primary cause of the error was a lack of effective internal controls. Field personnel failed to communicate the change in the sign flow to the LGE and KU Transmission Control Center and the LGE and KU Electric System Coordinator failed to recognize the change occurred.							
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The potential risk to the BPS could have been a generation deficiency and system imbalance. However, the actual risk to the BPS was minimal due to the small size of the Dynamic Schedule. The 6 to 8 MWs over generated resulted in an inaccurate ACE calculation; however, LGE and KU accounted for the 6 to 8 MWs as nominal to the Interconnection and did not impact real time operations. No harm is known to have occurred. SERC considered LGE and KU's compliance history and determined that there were no relevant instances of noncompliance.							
Mitigation	To mitigate this noncompliance, LGE and KU: 1) corrected the EMS value multiplier assigned to the load; 2) added limits to the SCADA key that reflects the dynamic schedule value; the Operator now will receive an alarm if this value received is smaller than -12.5 or larger than 0.1; 3) updated the BA desk procedure to explain why the Net Scheduled Interchange offset needs to be negative as well as adding a description of controls that are in place to indicate if a sign changes; and 4) communicated updated procedures that explain the negative load value, the origin of the load, and the alarms that LGE and KU installed.							

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017018557	FAC-009-1	R1	South Carolina Electric & Gas Company (SCEG)	NCR00915	06/18/2007	11/14/2018	On-site Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from July 18, 2017 to November 2, 2017, SERC determined that SCEG, as a Transmission Owner, was in noncompliance with FAC-008-3 R6. SERC determined that FAC-009-1 R1 was the applicable Standard and Requirement due to the duration of the noncompliance. SCEG did not have Facility Ratings for its solely and jointly owned Facilities that were consistent with its associated Facility Ratings Methodology (FRM). The audit team selected the Edenwood and Lake Murray 230/115kV transmission substations Facilities to conduct an inspection of the element Ratings that comprise each Facility Rating. Before the audit team arrived on-site to perform the facility inspections, SCEG performed a walk-down of the two Facilities. SCEG noted discrepancies between field element Ratings and the element Ratings used to determine Facility Ratings in SCEG's database. SCEG provided a list of those discrepancies to the audit team leader before the audit team arrived on-site. None of the element Rating discrepancies affected the Most Limiting Element (MLE) of the two Facilities. SCEG conducted an extent-of-condition assessment - to determine the complete scope of the discrepancies between the FRM and established Facility Ratings - by performing a walk-down of its Facilities (described in detail below) to review the accuracy of the physical components against the current drawings. SCEG identified the series elements for Facilities subject to FAC-008-3 R6 compliance, and reviewed each element Rating to ensure that it established each Rating in accordance with the FRM. SCEG reviewed the Facility Rating to ensure it used the correct Facility Rating in operations and made changes where discrepancies were identified. SERC initially requested a walk-down assessment of four generator Facilities and seven transmission substation Facilities. SCEG evaluated 83 element Ratings associated with these generator Facilities and did not identify any discrepancies with the generator element Ratings or Facility Ratings. As a result, SERC did not request an expansion of scope of this assessment. SCEG also evaluated 442 element Ratings associated with the transmission Facilities and identified 26 discrepancies. As a result, SERC requested that SCEG complete a walk-down assessment of all transmission Facilities. After completing a walk-down assessment of all transmission Facilities, SCEG identified 238 discrepancies from a total of 4,633 transmission elements. Five of the discrepancies impacted the MLE at four substations, one 115 kV/46 kV substation and three 230 kV/115 kV substations. SCEG did not exceed the correct Facility Rating in any instance. The percent difference between incorrect Ratings and correct Ratings ranged from 67% to 233%. For the five instances where a reduction of the Facility Rating occurred to adhere to the MLE, the percent difference between incorrect Ratings and correct Ratings ranged from 7% to 44%. In three of the five instances, field personnel installed a device with a different Rating than planned, or made a change in the field that they failed to communicate back to engineering/design department. The other two instances occurred due to failure to include an element in the calculation and due to incorrect information entered into the database. This noncompliance started on June 18, 2007, when FAC-009-1 became mandatory and enforceable, and ended on November 14, 2018, when SCEG revised the last incorrect Rating. The root cause of this noncompliance was a lack of effective internal controls. Specifically, SCEG did not have effective change management controls or oversight controls.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. SCEG's failure to develop Facility Ratings consistent with its FRM could have resulted in errors in the planning and operational models utilized by the Transmission Operator, Reliability Coordinator and Planning Authority, and could have led to equipment damage, unplanned outages or reduced equipment lifetimes. However, SCEG never exceeded the correct Facility Rating. Additionally, the discrepancies affected only 5% of its element Ratings and impacted only five Facility Ratings. No harm is known to have occurred. SERC considered SCEG's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, SCEG: 1) completed walk-downs of its Bulk Electric System and identified and resolved all discrepancies between field equipment Ratings, engineering drawings, and its Facility Ratings database; 2) implemented a new change management process for updating its Facility Ratings database and implemented single line diagrams to capture changes that occurred in the field, which included training appropriate personnel; and 3) implemented an internal control to address potential data input and calculation errors.

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SERC2018019864	MOD-025-2	R1.	SOWEGA Power, LLC (SOWEGA)	NCR01325	7/1/2016	6/27/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 15, 2018, SOWEGA submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R1. SOWEGA failed to provide its Transmission Planner (TP) with verification of the Real Power capability of its applicable Facilities in accordance with the NERC Implementation Plan. During a review, the plant manager and compliance contractor discovered that SOWEGA was no longer exempt under MOD-025-2 R1 as with the case under the previous MOD-024-1 and MOD-025-1 Standards, which were retired. Under the previous Standards, SERC developed procedures for verification of the generators Real Power capabilities in its region. The procedures from SERC created exemptions that SOWEGA met such that the verifications for the Real Power capability were not required. As of July 1, 2016, the Implementation Plan required 40% compliance of applicable units, but SOWEGA was 0% compliant. This noncompliance started on July 1, 2016, when the Standard became mandatory and enforceable, and SOWEGA failed to provide its TP staged verification data for Real Power capability of its generating units in accordance with Attachment 1, and ended on June 27, 2018, when SOWEGA provided its TP with verification of the Real Power capability of its units. The cause of the noncompliance was a lack of effective internal controls when MOD-025-2 R1 became effective and SOWEGA overlooked the new Standard during its quarterly compliance reviews. SOWEGA failed to realize it was no longer able to take the exemption for Real Power testing under the previous MOD-024-1 and MOD-025-1.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). SOWEGA's failure to provide verification and timely data from the staged test could have resulted in inaccurate system models. Due to SOWEGA's Combustion Turbine capabilities of 113.6 MVA and average three-year capacity factor of 11.1%, SOWEGA has minimal impact to the BPS. No harm is known to have occurred. SERC considered SOWEGA's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, SOWEGA: 7) completed MOD-025-2 R1 Real Power testing and submitted it on June 30, 2018, to its TP; 8) added a preventive maintenance task in its maintenance tracking system for the testing to be completed every five years per the Standard; and 9) included third-party contractor participation in quarterly compliance reviews to provide updates for new and existing Standards and Requirements.

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SERC2018019865	MOD-025-2	R2	SOWEGA Power LLC (SOWEGA)	NCR01325	07/01/2016	06/27/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 15, 2018, SOWEGA submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R2. SOWEGA failed to provide its Transmission Planner (TP) with verification of the Reactive Power capability of its applicable Facilities in accordance with the NERC Implantation Plan. During a review, the plant manager and compliance contractor discovered SOWEGA was no longer exempt under MOD-025-2 R2 as with the case under the previous MOD-024-1 and MOD-025-1 Standards, which were retired. Under the previous Standards, SERC developed procedures for verification of the generators reactive power capabilities in its region. The procedures from SERC created exemptions that SOWEGA met such that the verifications for the Reactive Power capability were not required. As of July 1, 2016, the Implementation Plan required 40% compliance of applicable units, but SOWEGA was 0% compliant. This noncompliance started on July 1, 2016, when the Standard became mandatory and enforceable, and SOWEGA failed to provide its TP staged verification data for Reactive Power capability of its generating units in accordance with Attachment 1, and ended on June 27, 2018, when SOWEGA provided its TP with verification of the Reactive Power capability of its units. The cause of the noncompliance was a lack of effective internal controls when MOD-025-2 R2 became effective and SOWEGA overlooked the new Standard during its quarterly compliance reviews. SOWEGA failed to realize it was no longer able to take the exemption for reactive power testing under the previous MOD-024-1 and MOD-025-1.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). SOWEGA's failure to provide verification data from a staged test and timely data from the staged test could have resulted in inaccurate system models. However, due to the average three-year capacity factor of 1.65%, the entity has little impact on the BPS. No harm is known to have occurred. SERC considered SOWEGA's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, SOWEGA: 10) completed MOD-025-2 R2 Reactive Power testing and submitted it on June 30, 2018, to its TP; 11) added a preventive maintenance task in its maintenance tracking system for the testing to be completed every five years per the Standard; and 12) included third-party contractor participation in quarterly compliance reviews to provide updates for new and existing Standards and Requirements.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021009	MOD-027-1	R3	Tennessee Valley Authority (TVA)	NCR01151	10/18/2017	01/24/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 28, 2019, TVA submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with MOD-027-1 R3. TVA failed to provide a written response to its Transmission Planner (TP), within 90 calendar days of receiving written notification from its TP, that the turbine/governor and load control or active power/frequency control model was not usable for 11 units. On August 31, 2017, the TP rejected the models for Kentucky Hydro Units 1, 2, 3, 4, and 5. On January 9, 2018, a Power Operations (PO) engineer, reviewing a personal task list, discovered that TVA failed to revise and re-submit the MOD-027-1 model data to the TP by November 29, 2017, as required. After the discovery, TVA reviewed the check list again to ensure no other MOD-027-1 actions were exceeding or approaching the 90-day limit. TVA did not identify any other late MOD-027-1 actions during this review. The task list showed the Hiwassee Hydro Units, Raccoon Pump Storage Units, and Wilson Hydro Units complete. These units were marked complete because the employee incorrectly believed that all of the issues the TP identified with these models had been resolved based on emails and phone discussions regarding the identified issues. On November 29, 2018, TVA assigned a different engineer, who was independent of the MOD-027-1 process, to conduct an assessment in preparation for the Self-Report. This assessment included all MOD-027-1 submissions from September 28, 2015 through November 29, 2018. This assessment identified issues with the data submissions for Hiwassee Hydro Unit 2, Raccoon Pump Storage Units 2, 3 and 4, and Wilson Hydro Units 20 and 21. In these three instances, TVA read the TP email as the problems were identified and resolved by the TP, however, the TP was expecting responses from GO. This noncompliance started on October 18, 2017, when TVA failed to submit the first submission by the October 17, 2018 due date, and ended on January 24, 2019, when TVA submitted the required information for all units. The root cause of the noncompliance was ineffective internal controls. An individual engineer maintained the MOD-027-1 implementation status spreadsheet. TVA did not implement secondary review to confirm all required tasks had been completed.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. TVA's failure to provide the TP with accurate data did not allow the TP to have model data that accurately represented generator unit real power response to system frequency variations when it ran dynamic simulations of the power system, which could have affected decision making in both the real-time and planning timeframes. However, this failure to respond to the TP was limited to 11 units, which represent less than 6% of TVA's generation. In addition, TVA had completed the R2 verification of turbine/governor and load control or active power/frequency control model and submitted it to its TP for 59% (24,445 MVA out of 41,568 MVA) of R2 when the implementation plan only required it to be at 30% completion by July 1, 2018 and 50% completion by July 1, 2020. As a result, TVA provided its TP with additional generation information for 29% more generation than required by the implementation plan, which should have positively impacted overall model accuracy. No harm is known to have occurred. SERC considered TVA's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, TVA: 1) submitted acceptable generator data to the TP for the noncompliant units; 2) eliminated parallel paths of coordination and oversight of MOD-027-1 test performance and report submittals a. TVA assigned a single manager with the oversight of execution of MOD-027-1 b. TVA will copy and send submittals and responses from a dedicated email address instead of an individual's email address; 3) established a Power Operations (PO) MOD-027 Status Tracking process for MOD-027 Data and Modeling Reports; TVA maintains the instructions for the process in the folder with the MOD-027-1 Status Spreadsheet; Data entered is peer checked for document dates and intent; 4) reorganized to provide a single oversight group for the PO organization, acting as the GO; TVA assigned one designated PO NERC Program Manager to act as the GO to review and submit all transmittals to the TP for MOD-027-1, copying transmittals and responses to a designated group-managed email address, which enhances MOD-027-1 reporting consistency and timeliness; and 5) communicated the established Status Tracking Change process to staff involved in the process.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021010	MOD-032-1	R2	Tennessee Valley Authority (TVA)	NCR01151	12/02/2017	01/29/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 25, 2019, TVA submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with MOD-032-1 R2. TVA failed to provide steady-state dynamics and short circuit modeling data to its Transmission Planner (TP) and Planning Coordinator (PC) according to the data requirements and reporting procedures developed by its TP and PC in Requirement R1 for the new Paradise Combined Cycle (PCC) units. TVA's TP established MOD-032 data transmittal requirements in TVA Transmission & Power Supply Procedure TVA-SPP-30-020. Step 3.2.1.C.2 of that procedure states, "The data owners shall submit their data to the PC and TP once annually no later than December 1 (starting calendar year 2016) (MOD-032-1 R1.2.4)." Based on this procedural requirement, TVA should have included the new PCC units in the 2017 MOD-032-1 data transmittal submitted to TVA's TP and PC on November 30, 2017 as PCC entered commercial operations in April 2017. During the January 2018 meeting of the TVA Generator Owners Group, TVA's TP and PC identified the omission of the PCC data from the GO's 2017 MOD-032-1 data transmittal to the TP and PC. Upon commercial operations in April 2017, TVA's Power Operations (PO) failed to move PCC from the "Under Construction" spreadsheet tab to the "Main" spreadsheet tab on the Excel Workbook associated with NERC MOD type data. PO failed to identify this error when it submitted the annual 2017 MOD-032-1 PO Data update to the TP and PC. This noncompliance started on December 2, 2017, the day after TVA failed to submit PCC data due to the TP and PC by December 1, 2017, and ended on January 29, 2018, when TVA submitted PCC data to the TP and PC. The root cause of the noncompliance was an ineffective internal control. The "New Unit Review" tracking report accurately indicated TVA had not completed the MOD-032 review requirement. TVA lost visibility of the pending status in part due to the complexity of the tracking mechanism.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). TVA's failure to submit modeling data could result in the PC and TP not having any data for PCC in its planning models and studies that would prevent the PC and TP from adequately conducting analyses of the system to support the reliability of the BPS. However, the PC and TP had the PCC unit data that TVA submitted during the construction phase and there were no changes from the 2016 data TVA submitted to the PC and TP. PCC represents only 1,389 MVA out of TVA's 41,788 MVA of generation therefore incomplete or inaccurate PCC unit data should have an insignificant impact to the BPS. No harm is known to have occurred. SERC considered TVAs compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, TVA: 1) submitted the PCC unit model data to its TP and PC; 2) added "new generation units pending Commercial Operations" to the PO MOD-032-1 data spreadsheet during the site construction period. TVA documented the instructions to be used for conducting the annual MOD-032-1 data update report on the spreadsheet, including the review of generation units under construction. Instead of waiting to add a PO generating site to the MOD-032-1 PO Data Spreadsheet when it becomes Commercially Operational, PO is adding them to the MOD-032-1 PO Data Spreadsheet during the construction phase of these units. Many of the data fields for the new units will be empty, but the site line item will be flagged with the scheduled Commercial Operation Date. The scheduled Commercial Operation date will be checked annually and updated when changes occur along with the other data; and 3) communicated the established process to the groups involved in the process.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021072	MOD-026-1	R2	Virginia Electric and Power Company - Power Generation (VEP-PG)	NCR09028	07/01/2018	09/10/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On February 19, 2019, VEP-PG submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-026-1 R2. VEP-PG failed to provide a verified generator excitation control system or plant volt/var control function model, including documentation and data to its Transmission Planner (TP), in accordance with the NERC implementation plan for 30% of the total applicable MVA by July 1, 2018. On December 13, 2018, after the reassignment of NERC Reliability Standard MOD-026-1 oversight from one employee to another, the receiving employee questioned the documentation required when taking an exemption based on the average net capacity factor over the most recent three calendar years. VEP-PG used a net capacity factor exemption to calculate required implementation plan percent complete. Originally, the VEP-PG lead for MOD-026-1 interpreted that the exemption could be applied to the existing total applicable MVA during initial evaluation of the unit's average net capacity factors and internal documentation of such satisfied the requirement. However, based on the clarification from SERC, the exemption is in effect on the date you submit a written statement to the TP. VEP-PG did not send written statements to the TP prior to the July 1, 2018 NERC Implementation Plan compliance date. VEP-PG used the net capacity factor exemption to calculate required implementation plan percent complete without the required TP submittal. The removal of the unauthorized exemption application resulted in a total applicable MVA of 24% instead of the required 30% necessary for compliance by July 1, 2018. This noncompliance started on July 1, 2018, when VEP-PG completed 24% instead of 30% of the MVA requirement, and ended on September 10, 2018, when VEP-PG provided the data for an additional plant which completed 34% of the MVA requirement. The root cause of the noncompliance was a misinterpretation of the Standard Implementation Plan.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. VEP-PG's failure to provide its TP verified model data could result in inaccurate system models. However, VEP-PG provided the data for an additional plant on September 10, 2018, which resulted in 34% of the 30% MVA requirement, only 71 days late for a requirement that has a full implementation requirement of July 1, 2024. No harm is known to have occurred. SERC determined that VEP-PG's MOD-026-1 R2 compliance history should not serve as a basis for applying a penalty. The underlying cause between the one prior noncompliance and instant noncompliance is different. The mitigation for the prior noncompliance would not have identified or prevented the instant noncompliance.
Mitigation	To mitigate this noncompliance, VEP-PG: 1) verified net capacity factors for all existing units and submitted written notice to the TP stating that an exemption is being applied; 2) updated VEP-PG's MOD-026 compliance tracking tool with the updated existing total applicable MVA in order to plan for future implementation milestones; 3) revised MOD-026 Administrative Document to incorporate a peer review process, as well as, specific language regarding the net capacity factor exemption process; 4) trained Power Generation Regulatory Compliance personnel on the revised MOD-026 Administrative Document; and 5) recalculated the total MVA, based on clarification from SERC, and documented in the tracking tool.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019021073	MOD-027-1	R2	Virginia Electric and Power Company - Power Generation (VEP-PG)	NCR09028	07/01/2018	09/10/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On February 19, 2019, VEP-PG submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-027-1 R2. VEP-PG failed to provide a verified turbine/governor and load control or active power/frequency control model, including documentation and data to its Transmission Planner (TP), in accordance with the NERC implementation plan for 30% of the total applicable MVA by July 1, 2018. On December 13, 2018, after the reassignment of NERC Reliability Standard MOD-027-1 oversight from one employee to another, the receiving employee questioned the documentation required when taking an exemption based on the average net capacity factor over the most recent three calendar years. VEP-PG used a net capacity factor exemption to calculate the required implementation plan percent complete. Originally, the VEP-PG lead for MOD-027-1 interpreted that the exemption could be applied to the existing total applicable MVA during initial evaluation of the unit's average net capacity factors and internal documentation of such satisfied the requirement. However, based on the clarification from SERC, the exemption is in effect on the date you submit a written statement to the TP. VEP-PG did not send written statements to the TP prior to the July 1, 2018 NERC Implementation Plan compliance date. VEP-PG used the net capacity factor exemption to calculate the required implementation plan percent complete without the appropriate required TP submittal. The removal of the unauthorized exemption application resulted in a total applicable MVA of 24% instead of the required 30% necessary for compliance by July 1, 2018. This noncompliance started on July 1, 2018, when VEP-PG completed 24% instead of 30% of the MVA requirement, and ended on September 10, 2018, when VEP-PG provided the data for an additional plant which completed 34% of the MVA requirement. The root cause of the noncompliance was a misinterpretation of the Standard Implementation Plan.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. VEP-PG's failure to provide its TP verified model data could results in inaccurate system models. However, VEP-PG provided the data for an additional plant on September 10, 2018, which resulted in 34% of the 30% MVA requirement, only 71 days late for a requirement that has a full implementation requirement of July 1, 2024. VEP-PG submitted the required data for 24% of the gross MVA by the July 1, 2018 requirement to submit 30% of the gross MVA data. No harm is known to have occurred. SERC determined that VEP-PG's MOD-027-1 R2 compliance history should not serve as a basis for applying a penalty. The underlying cause between the one prior noncompliance and instant noncompliance is different. The mitigation for the prior noncompliance would not have identified or prevented the instant noncompliance.
Mitigation	To mitigate this noncompliance, VEP-PG: 1) verified net capacity factors for all existing units and submitted written notification to the TP stating that an exemption was applied; 2) updated VEP-PG's MOD-027 compliance tracking tool with the updated existing total applicable MVA in order to plan for future implementation milestones; 3) revised MOD-027 Administrative Document to incorporate a peer review process, as well as, specific language regarding the net capacity factor exemption process; 4) trained Power Generation Regulatory Compliance personnel on the revised MOD-027 Administrative Document; and 5) recalculated the total MVA, based on clarification provided by SERC, and updated all tracking tools to reflect the change.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018020247	VAR-002-4	R3	EC&R QSE, LLC (ECR QSE)	NCR11383	06/10/2017	02/07/2018	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted per an existing multi-region registered entity agreement from May 29, 2018, through June 8, 2018, Texas RE determined that ECR QSE, as a Generator Operator (GOP), was in noncompliance with VAR-002-4 R3. Specifically, ECR QSE failed to notify its Transmission Operator (TOP) of status changes of the Automatic Voltage Regulator (AVR) at its generation Facilities within 30 minutes, as required by VAR-002-4 R3. The audit team reviewed historian data for ECR QSE's generating Facilities and determined that there were nine instances where the AVR changed from On-line to Off-line or from Off-line to On-line, and the respective GOP failed to notify its TOP of the AVR status changes. Six of the nine instances occurred in the Texas RE Region. These six instances occurred between June 15, 2017, and February 7, 2018, at the Pyron, Anacacho, and Panther Creek I Facilities where GOP Functions are completed by ECR QSE. Two of the nine instances occurred in the Reliability First Region. These two instances occurred on June 10, 2017, and June 13, 2017, at the Wildcat I Facility where Wildcat I Functions as both Generator Owner (GO) and GOP. One of the nine instances occurred in the Southeast Electric Reliability Council Region. This one instance occurred on August 17, 2017, at the Pioneer Trail Facility where Pioneer Trail Functions as both GO and GOP. In each of the nine aforementioned instances, the respective GOP notified the appropriate TOP of the AVR status change(s), but did so greater than 30 minutes after the status change. The root cause of the noncompliance was inadequate processes and training to ensure compliance with all applicable requirements in VAR-002-4 R3. Specifically, ECR QSE's respective GOPs did not adequately monitor the status of each AVR. This noncompliance started on June 10, 2017, when Wildcat I first failed to timely notify its TOP of its AVR status change, and continued intermittently at different Facilities until February 7, 2018, when ECR QSE placed the AVR back in service at Anacacho and notified its TOP of the AVR status change.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The maximum time-period between any of the AVR status changes and the time notification was made to the respective TOP was approximately two hours. No harm is known to have occurred. Texas RE considered ECR QSE's and its affiliates' VAR-002-4 compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, ECR QSE: 1) returned the AVR back to service at its Facilities; 2) conducted Control Room Operator training to set expectations on handling voltage and reactive control; 3) developed and implemented new control room alarms to enhance operator situational awareness; and 4) developed and implemented an email notification to advise control room operators of AVR status changes. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018020248	VAR-002-4	R2; R2.2; R2.3	EC&R QSE, LLC (ECR QSE)	NCR11383	06/10/2017	12/21/2018	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted per an existing multi-region registered entity agreement from May 29, 2018, through June 8, 2018, Texas RE determined that ECR QSE, Radford's Run Wind Farm, LLC (RRWF), Wildcat Wind Farm, LLC (Wildcat I), Pioneer Trail Wind Farm, LLC (Pioneer Trail), and Settlers Trail Wind Farm, LLC (Settlers Trail), as Generator Operators (GOPs), were in noncompliance with VAR-002-4 R2. Specifically, the Entities failed to maintain the generator voltage schedule provided by the Transmission Operator (TOP), in accordance with VAR-002-4 R2, provide an explanation of why the voltage schedule could not be met in accordance with VAR-002-4 R2.2, or have a methodology for converting the scheduled voltage in accordance with VAR-002-4 R2.3. ECR QSE and RRWF failed to comply with the provisions of the first paragraph of VAR-002-4 R2. The audit team reviewed historian voltage data and determined that there were numerous instances where the respective GOP failed to maintain the generator voltage schedule provided by the TOP, and failed to meet the conditions of notification for deviations from the voltage schedule. The instances in the Texas RE Region occurred at the Champion Wind Farm, LLC (CHA), Inadale Wind Farm, LLC (INA), Pyron Wind Farm, LLC (PYR), and Roscoe Wind Farm, LLC (ROS) where ECR QSE functions as the GOP. These instances occurred for various periods ranging from 20 minutes to approximately three hours between November 14, 2017, and November 17, 2017. The instances in the Reliability First (RF) Region occurred at RRWF, where RRWF functions as both Generator Owner (GO) and GOP. Each of these instances occurred for greater than 30 minutes between October 30, 2017, and December 3, 2017, on February 21 and 25, 2018, and December 20 and 21, 2018. In each of the above listed instances, ECR QSE's respective GOP failed to meet the conditions of notification of the TOP for deviations from the voltage schedule. ECR QSE failed to comply with the provisions of VAR-002-4 R2.2. The audit team reviewed historian voltage data and determined that there were three separate instances where ECR QSE failed to comply with an instruction from the TOP to modify voltage, or provide the TOP with an explanation of why the voltage schedule could not be met. These instances occurred in the Texas RE Region at the Panther Creek Wind Farm I &II, LLC (PC1/PC2), ROS, CHA, INA, and PYR where ECR QSE functions as the GOP. On June 10, 2017, ECR QSE was instructed to raise voltage at PC1/PC2 to 357 kV, but instead ECR QSE raised voltage to 356.5 kV. On October 10, 2017, ECR QSE was instructed to lower voltage by 2 kV at ROS, CHA, INA, and PYR, but instead ECR QSE lowered voltage by 0.5 kV. On October 16, 2017, ECR QSE was instructed to lower voltage at INA and PYR by 2 kV, but instead ECR QSE lowered voltage by 0.5 kV at PYR, and 1.0 kV at INA. Pioneer Trail, Settlers Trail, Wildcat I, and RRWF failed to comply with the provisions of VAR-002-4 R2.3. The audit team reviewed the evidence and determined that the Entities did not monitor voltage at the location specified in the voltage schedule, and did not have a proper methodology for converting the scheduled voltage specified by the TOP to the voltage point being monitored. The instances in the Southeast Electric Reliability Council (SERC) Region occurred at the Pioneer Trail, and Settler's Trail Wind Farms where these entities function as GO and GOP. A review of the distances between the locations specified in the voltage schedule, and the points actually monitored by ECR QSE, indicated these distances to be 3.02 miles in the case of Pioneer Trail, and 2.28 miles in the case of Settler's Trail. The instances in the RF Region occurred at the Wildcat I and RRWF where these entities function as GO and GOP. A review of the distances between the locations specified in the voltage schedule, and the points actually monitored by ECR QSE, indicated these distances to be 1.59 miles in the case of Wildcat I, and 7.3 miles in the case of RRWF. In each of the instances of noncompliance with VAR-002-4 R2, 2.3 in SERC and in RF, ECR QSE's methodology for converting the voltage, simply utilizing a 1:1 ratio, was determined to be erroneous due to the excessive distance and substantial potential for discrepancy between the location specified in the voltage schedule and the point actually monitored. The root cause of the noncompliance was ECR QSE's failure to require operators maintain situational awareness of plant performance with respect to the TOP provided voltage schedule, and to ensure that operators were versed in the appropriate operator response when deviations from the TOP provided voltage schedule occurred. The first instance of this noncompliance occurred on June 10, 2017, when ECR QSE first failed to follow the TOP instruction to raise voltage at PC1/PC2, and continued intermittently at different Facilities until December 21, 2018, when voltage at RRWF was returned within the tolerance band provided by the TOP.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Texas RE did not identify any trips or outages caused by the ECR QSE's failure to maintain its voltage output, or any unintended voltage controlling actions by the TOP that were related to ECR QSE's not monitoring its voltage at the designated point in its voltage schedule. The generation Facilities at issue are small, with an average nameplate rating of 175 MW, with the largest Facility at 305 MW. As a result, the wind generation Facilities in question would have had only a negligible impact on the system's ability to respond to voltage deviations. No harm is known to have occurred. Texas RE considered ECR QSE's and its affiliates' compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, ECR QSE: 1) conducted Control Room Operator training to set expectations on handling voltage and reactive control; and 2) developed and implemented new control center alarms to enhance operator situational awareness of the site's voltage schedule. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018019886	COM-001-2.1	R9	Wind Energy Transmission Texas, LLC (WETT)	NCR11074	05/01/2017	08/13/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from February 26, 2018, through June 12, 2018, Texas RE determined that WETT, as a Transmission Operator (TOP), was in noncompliance with COM-001-2.1 R9. Specifically, WETT did not have evidence to demonstrate testing its Alternative Interpersonal Communication (AIC) capability for the most recent 12 calendar months. In particular, WETT was unable to produce evidence of monthly satellite phone tests from May 2017 to July 2017. The root cause of this issue is that a logging software vendor change rendered evidence of prior testing inaccessible. For months subsequent to July 2017, WETT was able to provide evidence of monthly satellite phone tests. This noncompliance started on May 1, 2017, which is the first day after the end of calendar month April 2017, and ended on August 13, 2017, when WETT tested its Alternative Interpersonal Communication capability and documented the testing.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. First, WETT's primary communications systems were operational during the months for which WETT was missing testing records for its designated AIC system. Second, when WETT performed subsequent AIC capability for months subsequent to July 2017, it did not identify any issues with its designated AIC system. No harm is known to have occurred. Texas RE considered WETT's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, WETT: 1) tested its Alternative Interpersonal Communication capability and documented the testing; and 2) revised its Telecommunications (COM-001-3) Procedure; Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020107	MOD-026-1	R2	Meadow Creek Project Company LLC (MCREEK)	NCR11303	7/1/2018	7/11/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On July 20, 2018, MCREEK submitted a Self-Report stating, as a Generator Owner, it was in noncompliance with MOD-026-1 R2. Specifically, on July 1, 2018, MCRREK discovered it did not provide its Transmission Planner (TP) with a verified generator excitation control system or plant volt/var control function model, including documentation and data (as specified in Part 2.1) for its wind generating unit in accordance with the periodicity specified in MOD-026 Attachment 1 by July 1, 2018, in accordance with the MOD-026-1 Implementation Plan. MCREEK completed on-site testing and data collection work to verify the model prior to the deadline. However, due to the unavailability of existing plant voltage regulation models from the original equipment manufacturer (OEM) MCREEK did not have the entire scope necessary to develop the accurate model on its own and MCREEK outsourced the model verification to a third-party engineering firm to develop an accurate model in addition to the model validation. As a result, there was an increase in the engineering analysis scope to create an accurate model which led to MCREEK not being able to provide a complete verified voltage control model for its wind generating unit to its TP by the deadline. The root cause of the noncompliance was attributed to the unavailability of existing models from the OEM coupled with delays from a third-party engineering firm. After reviewing all relevant information, WECC Enforcement determined MCREEK failed to properly perform MOD-026-1 R2. This noncompliance began on July 1, 2018 when the Standard became mandatory and enforceable and ended on July 11, 2018, when MCREEK provided the verified voltage control model of its wind generating unit to its Transmission Planner for a total of 11 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, MCREEK failed to provide its Transmission Planner (TP) with a verified generator excitation control system or plant volt/var control function model, including documentation and data (as specified in Part 2.1) for its wind generating unit in accordance with the periodicity specified in MOD-026 Attachment 1 by July 1, 2018, in accordance with the MOD-026-1 Implementation Plan. However, MCREEK implemented good detective controls to prevent this noncompliance. Specifically, MCREEK participated in weekly NERC Compliance webinars that focused on NERC Standards, compliance review, and upcoming obligations for the Standards. As a result, MCREEK was aware of the issue and the deadline due to the mandatory and enforceable date of MOD-026-1, and subsequently self-reported the issue. Additionally, as compensation, this issue is related to a single intermittent wind generation facility with approximately 120 MW of generation that is subject to this instance and the Requirement is related to long-term planning. The verified model provided by MCREEK will contribute to the improvement in modeling accuracy but real-time operations. Providing this data 11 days later than required per the implementation plan has a very minimal impact on the reliability of the BPS. WECC considered the compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, MCREEK: 1) reviewed the third-party engineering firm model verification; 2) submitted a verified voltage control model for its wind generating unit to its TP; 3) utilized tracking software system to track upcoming and on-going compliance obligations; and 4) continued to participate in weekly NERC Compliance webinars. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020108	MOD-026-1	R2	Milford Wind Corridor Phase I, LLC (MILW)	NCR10394	7/1/2018	7/11/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On July 20, 2018, MILW submitted a Self-Report stating, as a Generator Owner, it was in noncompliance with MOD-026-1 R2. Specifically, on July 1, 2018, MILW discovered it did not provide its Transmission Planner (TP) with a verified generator excitation control system or plant volt/var control function model, including documentation and data (as specified in Part 2.1) for its wind generating unit in accordance with the periodicity specified in MOD-026 Attachment 1 by July 1, 2018, in accordance with the MOD-026-1 Implementation Plan. MILW completed on-site testing and data collection work to verify the model prior to the deadline. However, due to the unavailability of existing plant voltage regulation models from the original equipment manufacturer (OEM) MILW did not have the entire scope necessary to develop the accurate model on its own and MILW outsourced the model verification to a third-party engineering firm to develop an accurate model in addition to the model validation. As a result, there was an increase in the engineering analysis scope to create an accurate model which led to MILW not being able to provide a complete verified voltage control model for its wind generating unit to its TP by the deadline. The root cause of the noncompliance was attributed to the unavailability of existing models from the OEM coupled with delays from a third-party engineering firm. After reviewing all relevant information, WECC Enforcement determined MILW failed to properly perform MOD-026-1 R2. This noncompliance began on July 1, 2018 when the Standard became mandatory and enforceable and ended on July 11, 2018, when MILW provided the verified voltage control model of its wind generating unit to its Transmission Planner for a total of 11 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, MILW failed to provide its Transmission Planner (TP) with a verified generator excitation control system or plant volt/var control function model, including documentation and data (as specified in Part 2.1) for its wind generating unit in accordance with the periodicity specified in MOD-026 Attachment 1 by July 1, 2018, in accordance with the MOD-026-1 Implementation Plan. However, MILW implemented good detective controls. Specifically, MILW participated in weekly NERC Compliance webinars that focused on NERC Standards, compliance review, and upcoming obligations for the Standards. As a result, MILW was aware of the issue and the deadline due to the mandatory and enforceable date of MOD-026-1, and subsequently self-reported the issue. Additionally, as compensation, this issue is related to a single intermittent wind generation facility with approximately 305 MW of generation that is subject to this instance and the Requirement is related to long-term planning. The verified model provided by MILW will contribute to the improvement in modeling accuracy but real-time operations. Providing this data 11 days later than required per the implementation plan has a very minimal impact on the reliability of the BPS. WECC considered MILW's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, MILW: 1) reviewed the third-party engineering firm model verification; 2) submitted a verified voltage control model for its wind generating unit to its TP; 3) utilized a tracking software system to track upcoming and on-going compliance obligations; and 4) continued to participate in weekly NERC Awareness webinars. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2019021342	PRC-005-2	R1	Murray City Corporation (MUPD)	NCR05257	4/1/2015	7/6/2016	Spot Check	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	During a Spot Check conducted July 11, 2016, WECC determined the entity, as a Distribution Provider, had a potential noncompliance with PRC-005-2 R1. When PRC-005-2 R1 became mandatory and enforceable, the entity's Protection System Maintenance Program (PSMP) did not include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance and testing intervals. The following specific monitoring attributes were not correctly included on the following devices and corresponding Tables: Protective Relays (Table 1-1), Communications (Table 1-2), Potential Transformer/Current Transformer (Table 1-3), Batteries (Tables 1-4), Circuitry (Table 1-5), Alarming Paths and Monitoring (Table 2), and UFLS Distributed (Table 3). Following the Spot Check, on July 6, 2016, the entity updated its PSMP to include applicable monitoring attributes for monitoring, as stated in the relevant Tables of the Standard. WECC determined the issue associated with PRC-005-2 R1 began on April 1, 2015, when the Standard became mandatory and enforceable and ended on July 6, 2016, when the entity updated its PSMP, for a total of 463 days.
Risk Assessment	This WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to correctly identify specific monitoring attributes in its PSMP as described above, as required by PRC-005-2 R1. The entity implemented weak detective and preventative controls regarding these issues, as evidenced by the noncompliance duration. However, the entity implemented strong compensating controls. Specifically, no Misoperations, maintenance issues, or harm to the BPS resulted from these issues. Additionally, the entity used monitored microprocessor relays which increased the visibility of those devices. Lastly, applicable to these issues was 15 miles of 138 kV transmission lines, which step down to 12.5 kV for distribution to serve a peak load of 106 MW. Based on the voltage of the entity's system and amount of load served, the inherent potential harm during the noncompliance was negligible. WECC considered the entity's compliance history in its designation of these remediated issues as a CE. The entity's prior compliance history with PRC-005-1a R2 and PRC-005-2 R1 includes NERC Violation ID: WECC2012009846. WECC determined the entity's compliance history should not serve as a basis for pursuing an enforcement action and/or applying a penalty because the previous violation, was a documentation error including only three Protection System devices and not relevant to the facts and circumstances of the instant issue.
Mitigation	To mitigate this noncompliance, MUPD: To remediate this issue, the entity has: a. updated its PSMP to include Protective Relays (Table 1-1), Communications (Table 1-2), Potential Transformer/Current Transformer (Table 1-3), Batteries (Tables 1-4), Circuitry (Table 1-5), Alarming Paths and Monitoring (Table 2), and UFLS Distributed (Table 3), consistent with the current version of the Standard. The entity included the tables from the standard with annotations specific to the entity's equipment; b. retained guidance documentation from the Spot Check detailing the outreach and necessary improvements needed in future revisions to the PSMP; c. implemented an annual meeting with the substation technicians who perform the PSMP maintenance and testing to plan for the next year of testing and then updated the tracking spreadsheet accordingly; and

	d. stored the records of maintenance on its file server organized by year. The monthly or quarterly substation checks are tracked using a digital tracking sheet and the data is uploaded locally to a laptop and the file server. The CT test records and relays tests are stored locally on a laptop used in conjunction with the testing and the file server. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2019021343	PRC-005-1a	R2	Murray City Corporation (MUPD)	NCR05257	9/26/2011	6/23/2016	Spot Check	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	During a Spot Check conducted July 11, 2016, WECC determined the entity, as a Distribution Provider, had a potential noncompliance with PRC-005-1a R2. When PRC-005-1a R2 became mandatory and enforceable, the entity did not provide evidence that its Protection System devices were maintained and tested within the defined intervals nor did it provide the previous testing and maintenance date. Specifically, the entity did not provide evidence of the following: testing and maintenance records for two overcurrent relays and two differential relays; prior test dates and prior maintenance records for 18 current transformers and one differential relay; nor maintain three overcurrent relays devices within the defined interval, for a total of 26 Protection System devices. WECC determined this issue associated with PRC-005-1a R2 began on September 26, 2011, when the Standard became mandatory and enforceable and ended on June 23, 2016, when the entity provided evidence it had completed testing and maintained all 26 Protection System devices for a total of 1,733 days.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to provide evidence of testing and maintenance records for two overcurrent relays and two differential relays; prior test dates and prior maintenance records for 18 current transformers and one differential relay; nor maintain three overcurrent relays devices within the defined interval, for a total of 26 Protection System devices, as required by PRC-005-1a R2. The entity implemented weak detective and preventative controls regarding these issues, as evidenced by the noncompliance duration. However, the entity implemented strong compensating controls. Specifically, no Misoperations, maintenance issues, or harm to the BPS resulted from these issues. Additionally, the entity used monitored microprocessor relays which increased the visibility of those devices. Lastly, applicable to these issues was 15 miles of 138 kV transmission lines, which step down to 12.5 kV for distribution to serve a peak load of 106 MW. Based on the voltage of the entity's system and amount of load served, the inherent potential harm during the noncompliance was negligible. WECC considered the entity's compliance history in its designation of these remediated issues as a CE. The entity's prior compliance history with PRC-005-1a R2 and PRC-005-2 R1 includes NERC Violation ID: WECC2012009846. WECC determined the entity's compliance history should not serve as a basis for pursuing an enforcement action and/or applying a penalty because the previous violation, was a documentation error including only three Protection System devices and not relevant to the facts and circumstances of the instant issue.
Mitigation	To mitigate this issue, the entity has: a. completed maintenance and provided evidence for the 26 Protection System devices and documented the evidence; b. created a maintenance tracking spreadsheet and process that shows when all the devices were last tested and then they are due for future maintenance and trained staff regarding the tracking process. c. retained guidance documentation from the Spot Check detailing the outreach and necessary improvements needed in future revisions to the PSMP; d. implemented an annual meeting with the substation technicians who perform the PSMP maintenance and testing to plan for the next year of testing and then updated the tracking spreadsheet accordingly; and e. stored the records of maintenance on its file server organized by year. The monthly or quarterly substation checks are tracked using a digital tracking sheet and the data is uploaded locally to a laptop and the file server. The CT test records and relays tests are stored locally on a laptop used in conjunction with the testing and the file server. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2019021487	PRC-008-0	R2	Murray City Corporation (MUPD)	NCR05257	6/18/2007	6/13/2016	Spot Check	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	During a Spot Check conducted July 11, 2016, WECC determined the entity, as a Distribution Provider, had a potential noncompliance with PRC-008-0 R2. When PRC-008-0 R2 became mandatory and enforceable, the entity did not provide its Under Frequency Load Shedding (UFLS) test dates and maintenance records for eight UFLS relays. On April 30, 2019, the Regional Reliability Organization requested the maintenance and testing records prior to 2016 of the final scope of the Spot Check conducted in July 27, 2016. The entity responded to the request on May 6, 2019 demonstrating the entity had provided evidence it has completed maintenance and testing for the eight UFLS relays on June 13, 2016. WECC determined the issue associated with PRC-008-0 R2 began on June 18, 2007, when the entity did not provide testing dates and maintenance records for eight UFLS relays and ended on June 13, 2016, when the entity provided evidence it had completed testing and maintenance for eight UFLS relays, for a total of 3,284 days.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to provide evidence of its UFLS test dates and maintenance records for eight UFLS relays, as required by PRC-008-0 R2. The entity implemented weak detective and preventative controls regarding these issues, as evidenced by the noncompliance duration. However, the entity implemented strong compensating controls. Specifically, no Misoperations, maintenance issues, or harm to the BPS resulted from these issues. Additionally, the entity used monitored microprocessor relays which increased the visibility of those devices. Additionally, for the UFLS relays, the entity implemented a five-year maintenance interval, stricter than the minimum 12- year maintenance interval under the current version of the Standard. Lastly, applicable to these issues was 15 miles of 138 kV transmission lines, which step down to 12.5 kV for distribution to serve a peak load of 106 MW. Based on the voltage of the entity's system and amount of load served, the inherent potential harm during the noncompliance was negligible. WECC determined the entity did not have relevant compliance history with PRC-008-0 R2.
Mitigation	To mitigate this issue, the entity has: a. completed testing and maintenance activities and provided evidence for eight UFLS relays and documented the evidence; b. created a maintenance tracking spreadsheet and process that shows when all the devices were last tested and then they are due for future maintenance and trained staff regarding the tracking process. c. retained guidance documentation from the Spot Check detailing the outreach and necessary improvements needed in future revisions to the PSMP; d. implemented an annual meeting with the substation technicians who perform the PSMP maintenance and testing to plan for the next year of testing and then updated the tracking spreadsheet accordingly; and e. stored the records of maintenance on its file server organized by year. The monthly or quarterly substation checks are tracked using a digital tracking sheet and the data is uploaded locally to a laptop and the file server. The CT test records and relays tests are stored locally on a laptop used in conjunction with the testing and the file server. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020177	VAR-501-WECC-3.1	R2	Public Utility District No. 1 of Chelan County	NCR05338	3/12/2018	5/1/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On August 6, 2018, the entity submitted a Self-Report stating that, as a Generator Operator (GOP), it was in noncompliance with VAR-501-WECC-3.1 R2 and VAR-002-4.1 R3. Specifically, the entity was performing an exciter power system stabilizer (PSS) on one of its generators with a third-party consultant on May 1, 2018. During a test to simulate a voltage step change with the PSS enabled and disabled, the testing personnel noticed that the status of the PSS at the exciter did not match the status indicated for the unit's control system programmable logic controller (PLC). One device would indicate enabled and the other would indicate disabled. The PSS was switched between enabled and disabled several times and continued to display the opposite at the other location. The PLC requires that the PSS be enabled to start the generator. Given the conditions discovered while testing, to have had the enabled status at the PLC, the exciter PSS had to have been in a disabled status in the as-found state. Since the exciter is where the PSS resides, the status at the exciter determines whether the PSS is truly enabled or disabled. Further analysis determined the third-party consultants had changed the status logic during an exciter software revision on March 12, 2018. Thus, not only was the PSS disabled on the entity's generator while synchronized, but its TOP was not notified of the PSS being disabled from March 12, 2018 to May 1, 2018 in noncompliance of both VAR-501-WECC-3.1 R2 and VAR-002-4.1 R3, for a total of 51 days. After reviewing all relevant information, WECC determined that the entity failed to: a. have its PSS in service while synchronized, as required by VAR-501-WECC-3.1 R2; b. to notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change, as required by VAR-002-4.1 R3. The root cause of the VAR-501-WECC-3.1 R2 issue was attributed to the entity failing to account for the difference in the generator's configuration when the software update was applied resulting in the PLC showing the opposite status with no alarms being triggered. A contributing cause was a failure to test each unit and PSS for proper functionality after the software update was applied, due in part to an assumption that the process would not change for this unit based on the software update success with the previous units. The root cause of the VAR-002-4.1 R3 issue was attributed to downloading an incorrect configuration file that did not reflect previous changes in the wiring of the PSS to conform with the wiring of all the entity's generating units. The entity does not have any relevant previous violations of this or similar Standards and Requirements.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to: a. have its PSS in service while synchronized, as required by VAR-501-WECC-3.1 R2; b. to notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change, as required by VAR-002-4.1 R3. The issues were discovered relatively quickly and as further compensation, the generator at issue shares a common bus with another generator that had the PSS enabled, allowing the second generator's PSS to compensate for the first generator at the bus level. Furthermore, the entity's total generation at issue amounted to 54 MW, therefore if a contingency were to occur its harm would be negligible to the BES.
Mitigation	On July 18, 2018 the entity completed mitigating activities and on February 25, 2019, WECC verified completion of the entity's mitigating activities. To remediate and mitigate this issue, the entity has: a. notified the TOP of the status change on the PSS; b. enabled the PSS and breaker for the generator; c. established a work practice to verify functionality of all units after any software updates; and

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020177	VAR-501-WECC-3.1	R2	Public Utility District No. 1 of Chelan County	NCR05338	3/12/2018	5/1/2018	Self-Report	Completed
			d. created two new preventative maintenance schedules and associated job plans to generate annual work orders to verify that the PSS signal connection between the exciter and unit controls is correct.					

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020176	VAR-002-4.1	R3	Public Utility District No. 1 of Chelan County	NCR05338	3/12/2018	5/1/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible or confirmed violation.)	On August 6, 2018, the entity submitted a Self-Report stating that, as a Generator Operator (GOP), it was in noncompliance with VAR-501-WECC-3.1 R2 and VAR-002-4.1 R3. Specifically, the entity was performing an exciter power system stabilizer (PSS) on one of its generators with a third-party consultant on May 1, 2018. During a test to simulate a voltage step change with the PSS enabled and disabled, the testing personnel noticed that the status of the PSS at the exciter did not match the status indicated for the unit’s control system programmable logic controller (PLC). One device would indicate enabled and the other would indicate disabled. The PSS was switched between enabled and disabled several times and continued to display the opposite at the other location. The PLC requires that the PSS be enabled to start the generator. Given the conditions discovered while testing, to have had the enabled status at the PLC, the exciter PSS had to have been in a disabled status in the as-found state. Since the exciter is where the PSS resides, the status at the exciter determines whether the PSS is truly enabled or disabled. Further analysis determined the third-party consultants had changed the status logic during an exciter software revision on March 12, 2018. Thus, not only was the PSS disabled on the entity’s generator while synchronized, but its TOP was not notified of the PSS being disabled from March 12, 2018 to May 1, 2018 in noncompliance of both VAR-501-WECC-3.1 R2 and VAR-002-4.1 R3, for a total of 51 days. After reviewing all relevant information, WECC determined that the entity failed to: a. have its PSS in service while synchronized, as required by VAR-501-WECC-3.1 R2; b. to notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change, as required by VAR-002-4.1 R3. The root cause of the VAR-501-WECC-3.1 R2 issue was attributed to the entity failing to account for the difference in the generator’s configuration when the software update was applied resulting in the PLC showing the opposite status with no alarms being triggered. A contributing cause was a failure to test each unit and PSS for proper functionality after the software update was applied, due in part to an assumption that the process would not change for this unit based on the software update success with the previous units. The root cause of the VAR-002-4.1 R3 issue was attributed to downloading an incorrect configuration file that did not reflect previous changes in the wiring of the PSS to conform with the wiring of all the entity’s generating units. The entity does not have any relevant previous violations of this or similar Standards and Requirements.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to: c. have its PSS in service while synchronized, as required by VAR-501-WECC-3.1 R2; d. to notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change, as required by VAR-002-4.1 R3. The issues were discovered relatively quickly and as further compensation, the generator at issue shares a common bus with another generator that had the PSS enabled, allowing the second generator’s PSS to compensate for the first generator at the bus level. Furthermore, the entity’s total generation at issue amounted to 54 MW, therefore if a contingency were to occur its harm would be negligible to the BES.
Mitigation	On July 18, 2018 the entity completed mitigating activities and on February 25, 2019, WECC verified completion of the entity’s mitigating activities. To remediate and mitigate this issue, the entity has: a. notified the TOP of the status change on the PSS; b. enabled the PSS and breaker for the generator; c. established a work practice to verify functionality of all units after any software updates; and

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020176	VAR-002-4.1	R3	Public Utility District No. 1 of Chelan County	NCR05338	3/12/2018	5/1/2018	Self-Report	Completed
			d. created two new preventative maintenance schedules and associated job plans to generate annual work orders to verify that the PSS signal connection between the exciter and unit controls is correct.					

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020106	MOD-026-1	R2	Rockland Wind Farm LLC (RWFL)	NCR11214	7/1/2018	7/11/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On July 20, 2018, RWFL submitted a Self-Report stating, as a Generator Owner, it was in noncompliance with MOD-026-1 R2. Specifically, on July 1, 2018, RWFL discovered it did not provide its Transmission Planner (TP) with a verified generator excitation control system or plant volt/var control function model, including documentation and data (as specified in Part 2.1) for its wind generating unit in accordance with the periodicity specified in MOD-026 Attachment 1 by July 1, 2018, in accordance with the MOD-026-1 Implementation Plan. RWFL completed on-site testing and data collection work to verify the model prior to the deadline. However, due to the unavailability of existing plant voltage regulation models from the original equipment manufacturer (OEM) RWFL did not have the entire scope necessary to develop the accurate model on its own and RWFL outsourced the model verification to a third-party engineering firm to develop an accurate model in addition to the model validation. As a result, there was an increase in the engineering analysis scope to create an accurate model which led to RWFL not being able to provide a complete verified voltage control model for its wind generating unit to its TP by the deadline. The root cause of the noncompliance was attributed to the unavailability of existing models from the OEM coupled with delays from a third-party engineering firm. After reviewing all relevant information, WECC Enforcement determined RWFL failed to properly perform MOD-026-1 R2. This noncompliance began on July 1, 2018 when the Standard became mandatory and enforceable and ended on July 11, 2018, when RWFL provided the verified voltage control model of its wind generating unit to its Transmission Planner for a total of 11 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, RWFL failed to provide its Transmission Planner (TP) with a verified generator excitation control system or plant volt/var control function model, including documentation and data (as specified in Part 2.1) for its wind generating unit in accordance with the periodicity specified in MOD-026 Attachment 1 by July 1, 2018, in accordance with the MOD-026-1 Implementation Plan. However, RWFL implemented good detective controls to prevent this issue. Specifically, RWFL participated in weekly NERC Compliance webinars that focused on NERC Standards, compliance review, and upcoming obligations for the Standards. As a result, RWFL was aware of the issue and the deadline due to the mandatory and enforceable date of MOD-026-1, and subsequently self-reported the issue. Additionally, as compensation, this issue is related to a single intermittent wind generation facility with approximately 73 MW of generation that is subject to this instance and the Requirement is related to long-term planning. The verified model provided by RWFL will contribute to the improvement in modeling accuracy but real-time operations. Providing this data 11 days later than required per the implementation plan has a very minimal impact on the reliability of the BPS. WECC considered RWFL's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, RWFL: 1) reviewed the third-party engineering firm model verification; 2) submitted verified voltage control model for its wind generating unit to its TP; 3) utilized tracking software system to track upcoming and on-going compliance obligations; and 4) continued to participate in weekly NERC Compliance webinars. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019997	MOD-026-1	R2 R2.1	Rocky Mountain Power, LLC (RMPS)	NCR10197	07/01/2018	11/06/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On July 10, 2018, RMPS submitted a Self-Report stating, as a Generator Owner (GO), it was in potential noncompliance with MOD-026-1 R2. On July 1, 2018, RMPS discovered it did not provide its Transmission Planner (TP) with a verified generator excitation control system model of its generating unit in accordance with MOD-026 Attachment 1 by July 1, 2018, as directed in the associated Implementation Plans. Specifically, in December 2016, RMPS's one generating unit had fan bearing damage, which forced RMPS to take the unit offline. In January 2017, RMPS discovered a damaged disconnect at the generating unit and subsequently performed a dissolved gas analysis on its station auxiliary transformer, however, the test samples detected a fault. RMPS took the unit offline again until February 2017, when additional testing was performed on the station auxiliary transformer, but the new test samples still detected a transformer fault. As a result, RMPS had to order a new transformer which did not arrive at RMPS's site until October 2017. Further, RMPS decided to take its generating unit offline beginning November 2017 through January 2018, with the intention of starting back up in August 2018. Because the plant was offline and unavailable for testing, RMPS could not schedule the third-party testing company to perform the verification testing prior to the MOD-026-1 implementation timeline, which has been determined to be the root cause of the noncompliance. After reviewing all relevant information, WECC Enforcement determined RMPS failed to properly perform MOD-026-1 R2. This noncompliance began on July 1, 2018, when the Standards became mandatory and enforceable and ended on November 6, 2018, when RMPS provided the verified generator excitation control system model of the generating unit to its TP for a total of 129 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, RMPS failed to provide its Transmission Planner (TP) with a verified generator excitation control system or plant volt/var control function model including documentation and data (as specified in Part 2.1) for its one generating unit in accordance with the periodicity specified in MOD-026 Attachment 1 by July 1, 2018, as directed in the Implementation Plan. As compensation, the models required by the Standards are used for long term planning and would not result in immediate harm to the BPS. Additionally, RMPS's generating unit has a nameplate rating of 135 MVA, further reducing the risk. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, RMPS: 1) performed the verification model testing and provided the verified generator excitation control system model and turbine/governor model verification of its generating unit. Specific future prevention activities are not required for this instance of noncompliance due to the identified root cause being that the plant was offline for several reasons out of RMPS' control. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019998	MOD-027-1	R2 R2.1	Rocky Mountain Power, LLC (RMPS)	NCR10197	07/01/2018	11/06/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On July 10, 2018, RMPS submitted a Self-Report stating, as a Generator Owner (GO), it was in potential noncompliance with MOD-027-1 R2. On July 1, 2018, RMPS discovered it did not provide its Transmission Planner (TP) with a verified generator excitation control system model and the turbine/governor model verification of its generating unit in accordance with MOD-027 Attachment 1 by July 1, 2018, as directed in the Implementation Plan. Specifically, in December 2016, RMPS's one generating unit had fan bearing damage, which forced RMPS to take the unit offline. In January 2017, RMPS discovered a damaged disconnect at the generating unit and subsequently performed a dissolved gas analysis on its station auxiliary transformer, however, the test samples detected a fault. RMPS took the unit offline again until February 2017, when additional testing was performed on the station auxiliary transformer, but the new test samples still detected a transformer fault. As a result, RMPS had to order a new transformer which did not arrive at RMPS's site until October 2017. Further, RMPS decided to take its generating unit offline beginning November 2017 through January 2018, with the intention of starting back up in August 2018. Because the plant was offline and unavailable for testing, RMPS could not schedule the third-party testing company to perform the verification testing prior to the MOD-027-1 implementation timeline, which has been determined to be the root cause of the issue. After reviewing all relevant information, WECC Enforcement determined RMPS failed to properly perform MOD-027-1 R2. This noncompliance began on July 1, 2018, when the Standards became mandatory and enforceable and ended on November 6, 2018, when RMPS provided the verified generator excitation control system model and the turbine/governor model verification of the generating unit to its TP for a total of 129 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, RMPS failed to provide its Transmission Planner (TP) with a verified turbine/governor and load control or active power/frequency control model, including documentation and data (as specified in Part 2.1) for its one generating unit in accordance with the periodicity specified in MOD-027 Attachment 1 by July 1, 2018, as directed in the Implementation Plan. As compensation, the models required by the Standards are used for long term planning and would not result in immediate harm to the BPS. Additionally, RMPS's generating unit has a nameplate rating of 135 MVA, further reducing the risk.
Mitigation	To mitigate this noncompliance, RMPS: 1) performed the verification model testing and provided the verified generator excitation control system model and turbine/governor model verification of its generating unit. Specific future prevention activities are not required for this instance of noncompliance due to the identified root cause being that the plant was offline for several reasons out of RMPS' control. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017136	MOD-032-1	R2	Spring Canyon Energy LLC (SPCE)	NCR11529	7/1/2016	7/27/2017	Self-Certification	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On February 28, 2017, SPCE submitted a Self-Certification stating, as a Generator Owner (GO), it was in noncompliance with MOD-032-1 R2. This issue began on July 1, 2016, when the standard became mandatory and enforceable and ended on July 27, 2017, when SPCE provided its steady-state, dynamics, and short circuit modeling data for its wind generation units to its TP and PC for a total of 392 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, SPCE failed to provide its steady-state, dynamics, and short circuit modeling data to its Transmission Planner and Planning Coordinator according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1, as required by MOD-032-1 R2. SPCE had weak preventative controls to prevent this issue for occurring. However, as compensation, the unit in scope generates 60 MW while operating and operates at an average 35% capacity factor, which would only cause minor variation in planning results, thus reducing the risk to the BPS to negligible. No harm is known to have occurred. WECC considered SPCE's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, SPCE: 1) submitted its steady-state, dynamics, and short circuit modeling data to its TP/PC; 2) created and implemented an automated task notification to remind responsible personnel 60 days prior to each targeted 12-month review period, task is escalated to compliance team if not completed within 30 days of due date; 3) provided additional training to entity's compliance team with emphasis on model guidelines and future model update expectations; 4) expanded its compliance team capacity by two personnel to better manage and monitor performance action dates; and 5) updated its contact sheet for all third-party compliance partners (RC, BA TP, PC) to ensure contact information is correct and available, the contact sheet will be reviewed and updated on regular basis. SPCE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020361	VAR-002-4.1	R2	CHI Power, Inc (CHI P)	NCR10316	01/01/2018	06/27/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 11, 2018, CHI P submitted a Self-Report stating that as a Generator Operator, it was in noncompliance with VAR-002-4.1 R2. Per CHI P, Reactive Power measurements in CHI P's Control Room were incorrect for its Thunder Ranch Facility (TRWF). The Control Room measurements showed that the site was within the prescribed Transmission Operator (TOP) Reactive Power schedule; however, an on-site SCADA engineer discovered that the TRWF was producing Reactive Power in excess of the Control Room measurement. CHI P subsequently reviewed its historical operations based on actual Reactive Power outputs and determined that the TRWF was not meeting the Reactive Power schedule set by its TOP. The cause of the noncompliance was CHI P did not have adequate alarming to inform operators of VAR measurement discrepancies between its TRWF Facility and Control Center. The issue began January 1, 2018, the TRWF's commercial operating date, and ended on June 27, 2018 when the measurement discrepancy error was corrected and a notification was provided to the TOP.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Due to TRWF's relatively small size (300 MW), TRWF would have limited effect on the larger system's ability to respond to Reactive Power demands or control voltage. Additionally, the noncompliance did not have any adverse effects on the BPS. TRWF is not a part of a Remedial Action Scheme, is not a Blackstart Resource, and is not associated with any Interconnection Reliability Operating Limit (IROL). Further, per TRWF, the scheduled reactive power limit for this facility was 5 MVAR, and the reactive power schedule exceedance was limited to 3 MVAR on average during the period of noncompliance. Finally, CHI P conducted an extent of condition review and confirmed that TRWF was the only Facility with this issue, as TRWF is CHI P's only site that is required to operate in Reactive Power Control mode. No harm is known to have occurred. CHI P has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, CHI P: 1) notified its Transmission Operator that the Reactive Power schedule had not been maintained due to the issue; 2) corrected the compensation calculation on the VAR controller at TRWF to eliminate the measurement discrepancy issue; 3) updated its alarming and monitoring to include TRWF's Reactive Power value at the point of interconnection, which would detect similar issues in the future; and 4) updated training materials in the Control Monitoring Room based on lessons learned from this noncompliance, which included retraining on notifying the TOP even if the noncompliance is still being investigated and handling of the unique circumstances at TRWF since it is the only site that is required to operate in Reactive Power mode.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018019388	PRC-005-2(i)	R3	Glencoe Light and Power Commission (GLP)	NCR11444	12/01/2016	01/11/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On March 5, 2018, GLP submitted a Self-Report stating that, as a Transmission Owner, it was in noncompliance with PRC-005-2(i) R3. GLP reported that it failed to complete the required impedance testing on batteries at two substations per the 18 month interval prescribed by PRC-005-2(i) R3. The cause of the noncompliance was that GLP's processes and controls were deficient. The noncompliance began on December 1, 2016, 18 months after the previously completed impedance tests, and ended on January 11, 2018, when the battery impedance tests were completed at both substations.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). GLP states that there were no performance issues with the batteries that were identified by the impendence testing once the testing was performed. Further, GLP's two substations have a maximum voltage of 115 kV, limiting the potential risk to the BPS. Finally, GLP does not own any Facilities associated with a Remedial Action Scheme (RAS), Interconnection Reliability Operating Limit (IROL), or Blackstart Cranking Path. No harm is known to have occurred. GLP has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, GLP: 1) performed the missing tests; and 2) implemented a compliance calendar with quarterly review sessions to evaluate adherence to the required maintenance intervals.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020551	TOP-001-3	R14	Minnesota Power (Allete, Inc.) (MP)	NCR00674	05/13/2018	05/13/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 10, 2018, MP submitted a Self-Log stating that, as a Transmission Operator, it was in noncompliance with TOP-001-3 R14. MP reported that it failed to initiate its Operating Plan to mitigate a System Operating Limit (SOL) exceedance identified as part of its Real-time monitoring or Real-time Assessment. Three MP Transmission Lines utilize dynamic (temperature) based limits to calculate SOLs. The temperature is recorded and imported to the EMS, which updates the limit in real-time for System Operators. In this instance, a 115 kV transmission line that utilized temperature based limits exceeded its limit at 12:53 on May 13, 2018 and was not mitigated until 18:15 when it was removed from service per the MP Operating Guide. MP's Operating Plan indicates that SOL exceedances are to be mitigated within 30 minutes. MP reported that the cause of the noncompliance was that the alarm received in response to the ratings exceedance was incorrectly classified as a "priority two" (lower priority) alarm in the EMS. Therefore, as a result of the incorrect alarm classification, the alarm was dismissed by the System Operator without immediate response and MP failed to mitigate the SOL exceedance within 30 minutes as stated in MP's Operating Plan. The noncompliance began on May 13, 2018, when MP failed to implement its Operating Plan to mitigate SOL exceedances within 30 minutes, and ended approximately five hours later when MP implemented its Operating Plan.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). As detailed in its Operating Guide, the mitigation for SOL exceedances on the 115 kV transmission line is to remove the line from service. Offline studies and RTCA results indicated that the loss of this line would not cause any adverse reliability impact to the BPS. Additionally, the dynamic (temperature) ratings system does not currently utilize wind speeds to assist in determining the rating limit. During the noncompliance, the actual line flows did not exceed 61 MVA . MP performed a post-mortem analysis of the line rating including a 10 MPH wind speed, and determined that the line limit could have safely been at least 76 MVA for the period of noncompliance. Finally, the Transmission Line is not associated with a Blackstart Cranking Path, Remedial Action Scheme, or an Interconnection Reliability Operating Limit (IROL). No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, MP: 1) removed the Transmission Line from service per the Operating Guide; 2) changed the alarm classifications for its Transmission Lines that utilize dynamic (temperature) ratings from "priority two" to "priority one" alarms. Priority one alarms necessitate immediate action or response from a System Operator; 3) provided refresher training for its System Operators on MP's utilization of Dynamic Limits; and 4) updated its dynamic ratings in the applicable models.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020215	TOP-001-4	R20	Muscatine Power & Water (Board Of Water, Electric & Communications) (MPW)	NCR00967	07/01/2018	08/14/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On August 14, 2018, MPW submitted a Self-Report stating that as a Transmission Operator, it was in noncompliance with TOP-001-4 R20. MPW reported that at its primary Control Center, there was only a single hub to its Reliability Coordinator (RC) outside of the SCADA ESP connecting to a single port on the MPW SCADA firewall. This hub served as a concentration point, routing ICCP communications to its RC for the exchange of Real-time Assessment data. MPW determined that a second RC hub was needed to have fully redundant data exchange infrastructure per TOP-001-4 R20. The cause of the noncompliance was that MPW misinterpreted the redundancy requirements in the new version of the Standard. The noncompliance began on July 1, 2018, when the Standard and Requirement became enforceable and ended on August 14, 2018 when MPW reconfigured its connection to have a redundant result.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). MPW has its RC's RTCA designated as its primary Real Time Analysis tool, and MPW has fully redundant ICCP communications with its RC. In the event of failure of any of the data exchange infrastructure within the Primary Control Center, ICCP communications are rerouted through the Backup Control Center and System Operators continue to be able to perform Real-time Assessments. MPW's transmission system poses a limited risk to the reliability of the BPS. MPW owns and operates approximately 33 miles of 161 kV transmission, which limits the potential risk as indicated by its Transmission Portfolio and Critical Transmission ERO Risk Factors. MPW does not own nor operate any Blackstart resources, cranking paths, or Interconnection Reliability Operating Limit (IROL). No harm is known to have occurred. MPW has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, MPW eliminated the single RC hub and configured separate direct connections from each RC firewall to separate ports on MPW's SCADA firewall; therefore achieving the desired redundant result.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020553	COM-001-3	R10	Otter Tail Power Company (OTP)	NCR01023	08/23/2018	08/23/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 10, 2018, Otter Tail Power (OTP) submitted a Self-Log stating that, as a Transmission Operator (TOP), it was in noncompliance with COM-001-3 R10. OTP states that its Reliability Coordinator (RC) contacted the OTP Power System Operator (PSO) via the MSAT radio reporting that it was unable to contact OTP by normal phone. OTP imitated its Standard Operating Procedure (SOP) 13 (Communications Capabilities) regarding the loss of interpersonal communications. OTP notified its Reliability Coordinator, its Balancing Authority, neighboring TOPs, some of the Distribution Providers (DP) within its TOP area, and some of the Generator Operators (GOP) within its TOP area via its RC's Communications System (MCS) of the problem and provided alternate phone numbers. Some DPs and GOPs within OTP's TOP area that do not use the MCS, were not notified. The cause of the noncompliance was an inadequate procedure. OTP's SOP 13 (Communications Capabilities) instructs PSOs to contact counterparts using the alternate communication method. Alternate methods had not been identified for these DPs and GOPs that do not own the MISO MCS. The noncompliance began on August 23, 2018; 60 minutes after OTP detected its communication failure, and ended approximately eight hours later when its communication system was fully resolved.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. OTP notified the RC and adjacent TOPs that are considered critical to the reliable operation of the interconnected transmission systems. Additionally, the DPs and GOPs that did not receive a notification would not typically be contacted for real-time operations. Furthermore, the ability of these entities to communicate in real time with OTP has a minimal effect on BES reliability due to their small size and the limited operational nature of the DP and GOP functions. No harm is known to have occurred.
Mitigation	To mitigate this reoccurrence for the noncompliance, OTP: 1) had their System Operations group revise SOP 13 (Communications Capability); the revised version includes documentation of alternate communication methods for all entities in the OTP TOP area; and 2) provided refresher training to all PSOs on the new SOP 13.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2019020992	PRC-005-2(i)	R3	Southern Minnesota Municipal Power Agency (SMMPA)	NCR01030	10/01/2015	05/29/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 14, 2019, Southern Minnesota Municipal Power Agency (SMMPA) submitted a Self-Report stating that as a Transmission Operator it was in noncompliance with PRC-005-2(i) R3. Table 1-4(a) of standard PRC-005-2(i) and PRC-005-6 requires DC supply maintenance activities to be performed on a four calendar month interval. Table 1-2 of PRC-005-6 requires communications systems maintenance activities to be performed on a six calendar year interval. SMMPA states that during an internal review, it discovered three instances where maintenance activities were not performed as required by Table 1-4 (a) or Table 1-2. In the first instance, SMMPA discovered a substation battery bank that had only its supply voltage verified and lacked documentation to demonstrate that it had been inspected for electrolyte levels or unintentional grounds. The cause of the noncompliance was that SMMPA did not follow its processes to ensure that adequate testing was completed or adequate documentation was being retained. The required maintenance was not performed according to schedule and the entity was in non-compliance between October 1, 2015 and November 20, 2015. In the second instance, there was not sufficient documentation for the maintenance of a substation battery bank. SMMPA reports that the cause of the lack of documentation corresponds with the maintenance provider’s change in its compliance software program. SMMPA states that the lack of documentation impacts maintenance activities that were required to be performed resulted in a period of noncompliance between March 31, 2017 and May 17, 2018. The third instance involved four communication relays between two substations. SMMPA failed to perform a lack of end-to-end testing between the substations. The noncompliance was caused by a failure to coordinate maintenance between two maintenance providers. The noncompliance began on December 31, 2016 and the test was not completed until May 29, 2019. The noncompliance was noncontiguous; the noncompliance began on October 1, 2015, when SMMPA missed the first interval in instance one, and ended on May 29, 2019, when the relays in instance three were tested.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. SMMPA states that the noncompliance in instance one and two were confirmed to be limited to a single substation by an extent of condition review. Additionally, SMMPA states that the noncompliance in instance three were confirmed to be limited to a single Transmission Line by an extent of condition review. Further, SMMPA states that there were no misoperations or events during the period of noncompliance due to a loss of substation DC supply or Protection System issues. Finally, SMMPA’s transmission facilities are not part of any Interconnection Reliability Operating Limit (IROL) or Remedial Action Scheme (RAS). No harm is known to have occurred. SMMPA has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, SMMPA: To mitigate noncompliance for the first instance, SMMPA: 1) completed the all the required equipment testing; and 2) provided training to the maintenance provider/substation technicians regarding the documentation requirements for PRC-005 R3. To mitigate noncompliance for the second instance, SMMPA: 1) finished compiling the missing documentation; 2) provided training to improve the familiarity with the compliance software; and 3) assigned each maintenance activity a measurement point in the compliance software for completion recording and reporting. To mitigate noncompliance for the third instance, SMMPA: 1) completed the required end-to-end testing; and 2) put one maintenance provider in charge of testing both sides of the line.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2019020896	BAL-005-0.2b	R7	Western Area Power Administration - Upper Great Plains East (WAPA)	NCR01036	10/17/2018	10/17/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On November 5, 2018, WAPA submitted a Self-Report stating that, as a Balancing Authority, it was in noncompliance with BAL-005-0.2b R7. WAPA states that on October 17, 2018, it failed to resume Automatic Generation Control (AGC) for Fort Peck Generation Unit #1 after testing had been complete. WAPA needed to suspend AGC while testing was being done on the unit, however, WAPA reports that it did not promptly reinstate AGC after the testing was complete. AGC was reinstated approximately 90 minutes after testing was complete. The cause of the noncompliance is that the System Operator became distracted by another task and failed to resume AGC once testing was complete. This noncompliance started on October 17, 2018, when WAPA did not reinstate AGC after the testing was complete and ended approximately 90 minutes, when AGC was reinstated.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The currently enforceable Standard, BAL-005-1 does not include the requirement that the Balancing Authority operate the AGC. Additionally, WAPA reports that it remained with +/- 3 MW and did not have any ACE Limit exceedances during the period of noncompliance. No harm is known to have occurred. WAPA has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, WAPA: 1) resumed AGC mode; 2) discussed the issue with the System Operator that became distracted; and 3) included BAL-005-0.2b R7 related content in its 2019 Spring Dispatcher Training.

NERC Noncompliance ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Mitigation Completion Date
NPCC2019021286	FAC-014-2	R2	Consolidated Edison Company of NY, Inc	NCR07046	7/1/2016	11/16/2018	Self-Log	11/16/2018

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On April 1, 2019, Consolidated Edison Company of NY, Inc ("the Entity") submitted a Self-Log stating that as a Transmission Operator (TOP), it was in noncompliance with FAC-014-2 R2. Following submission of a separate Self-Report of potential noncompliance of FAC-008-3 R6 for incorrect feeder ratings, the Entity performed an internal review of System Operating Limits (SOLs) utilized in its Energy Management System (EMS) for monitoring and implementing real-time system operation. The process in place for establishing SOLs is currently implemented by the EMS group who, upon review of thermal ratings provided by the Engineering group for individual components of every transmission feeder, manually input into EMS the most limiting rating as representative of individual feeders' SOLs. This internal investigation concluded that the SOLs for two regulated 138 kV feeders were incorrectly determined. This noncompliance started on July 1, 2016, when the two feeders were classified as BES elements and thus in scope of the standard, and ended on November 16, 2018, when the noncompliant SOLs were corrected in the Entity's EMS system. On this same day, the Entity also provided the corrected SOLs to its Reliability Coordinator (the NYISO). The root cause of this potential noncompliance is a failure of the EMS group to select the ratings of the most thermally limiting component of a feeder in order to establish correct SOLs in the EMS system for the two aforementioned 138 kV feeders.
Risk Assessment	This violation posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The Entity owns 175 BES transmission feeders, of which two were affected by this instance of noncompliance. More specifically, the noncompliance consisted of the use of incorrect SOLs for two 138 kV feeders (Feeders 331 and 332) in the Entity's EMS' real-time monitoring and contingency analysis (CA) programs. Each of the two feeders is comprised of three elements in series: a transformer, a phase angle regulator (PAR) and a cable section. The most limiting element of the series components under most of the rating scenarios is the PAR or the transformer, not the cable. • In the RT program, the rating entries for these two feeders were based on their respective transformer rating for Normal, LTE, and STE for Summer and Winter. However, the PAR is actually the limiting element for Normal and LTE for Summer and Winter; but the maximum MW difference in those cases is only 8 MW. • In the CA program, the ratings entries for these two feeders were based on their respective cable ratings. However, either the PAR or transformer is limiting element for all ratings level (Normal, LTE, STE for Summer and Winter), not the cable. This resulted in CA alarm points being calculated artificially higher by the following percentages: Summer Normal 27%, LTE 31%, STE: 38%, Winter Normal 22%, LTE: 25%, STE: 27%. The reliability risk of entering the incorrect SOLs into the EMS was lessened by three factors. 1) A Second Contingency Design is afforded to the area of the system affected by this noncompliance (i.e. the ability to return the system to within its normal state performance limits without any load shedding after the occurrence of two non-simultaneous design contingencies). 2) The incorrect SOLs affect two 138 kV feeders that are associated with a 138 kV interface and 138 kV load pocket that does not have operational impact on any of the RC's (the NYISO) IROL interfaces. 3) The degree of the incorrectness of the ratings entries was not of a large nature in the real time system. In real time, the System Operator must procedurally get below LTE within 15 minutes and below STE within 5 minutes. As stated above for the case of real time awareness, the EMS was showing a maximum incorrect rating of 8 MW and there were no instances during this noncompliance where the two feeders ever exceeded in real time their Normal or LTE rating that was entered in the real time aspect of the EMS. From the perspective of post contingency awareness and alarms, the System Operator is not allowed to be in a state where there are post-contingency STE alarms while the System Operator is allowed to be in a state where there are post-contingency LTE alarms. The post-contingency alarms are presented to the System Operator on an N-1 basis. Operational studies were run against the largest system contingencies and the contingencies local to the 138 kV interface and load pocket in question. The results showed that the worst case would have been that the two parallel feeders would have gone over the corrected LTE in real-time (an allowable state) whereby the System Operator would have followed procedure to reduce the flow back below the corrected LTE within 15 minutes. The feeders in question would have never gone over the corrected STE in real time based on all of the contingencies studied. No actual harm is known to have occurred.
Mitigation	To rectify the noncompliance and prevent a recurrence, the Entity: 1. Corrected the noncompliant SOLs for the two 138 kV feeders in its EMS system and provided them to its RC.

	2. Improved the process of establishing SOLs by enlisting the help of another group, the Operations Analysis group, to perform a peer review of the SOLs determinations made by the EMS group. 3. Enhanced feeders' ratings spreadsheets produced by the Engineering group by prominently highlighting the most limiting rating of the various components of a transmission feeder.

NERC Noncompliance ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Mitigation Completion Date
NPCC2019021716	PRC-001-1.1	R3	Rumford Power Inc.	NCR11130	5/7/2015	7/2/2019	Self-Report	7/2/2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On June 20, 2019, Rumford Power Inc. ("the Entity") submitted a self-report stating that, as a Generator Operator ("GOP"), it was in noncompliance with PRC-001-1.1 R3. Specifically, on two occasions, the Entityfailed to coordinate the implementation of certain changes to its protective systems with its Host Balancing Authority ("BA"). There were two instances of noncompliance. The first began on May 7, 2015, when the Entity failed to notify its Host BA of changes implemented to its protection system relaying and ended on July 2, 2019, when the Entity sent a communication to its Host BA regarding the protective system changes. The changes were an in-kind replacement of two existing protection relays for two generating units and the installation of two back-up transformer differential protective relays for both the Steam and Gas Turbine's Generator Step-up Transformers (GSUs). The second instance began on September 12, 2016, when the Entity failed to notify its Host BA of relay setting changes to its protection systems and ended on June 27, 2019, when the entity notified its Host BA of those changes. The changes were to the Entity's generation excitation limiters' Volts/Hz relays (Device 24) settings that resulted from compliance activities associated with the application of Reliability Standard PRC-019-2. NPCC determined that the Entity was in noncompliance with PRC-001-1.1 R3 from May 7, 2015 until May 28, 2015 and then was in noncompliance with PRC-001-1.1(ii) R3 from May 29, 2015 until July 2, 2019. NPCC further determined that, for purposes of this noncompliance, there was no substantive change in its compliance obligations under the two applicable Standard Requirements. The root cause of this instance of non-compliance was the Entity's inability to establish communication channels with the appropriate Host BA staff and a misunderstanding of the process to follow regarding the coordination of protective system changes.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Failure to coordinate changes to protective systems could result in a misunderstanding of the protective systems settings, which could result in such protective systems not being implemented or operated correctly. However, in this case, the Entity did coordinate the changes to its protective system with its TOP on both occasions. Additionally, in the first instance, the protection system changes were implemented without any changes to the pre-existing relay settings for either the generating units or their GSUs. In the second instance, the changes were part of compliance activities associated with the application of PRC-019-2, which resulted in changes to the settings of the Entity's generation excitation limiters to prevent an unnecessary tripping. The Entity owns two generating facilities that are in scope of the standard, a Gas Turbine and a Steam Turbine, which are normally operated as a single Combined Cycle plant. The facilities are interconnected to a 115 kV substation owned by the Host TO. The Entity's two generating facilities have a combined rated capacity of approximately 265 MW. The combined average annual capacity factors for the two units have been 10.3% (in 2017), 6.7% (in 2018) and 0.1% (in 2019, to date). By comparison, the Entity's Reliability Coordinator (ISO-NE) carries required Operating Reserves of approximately 2600 MW and could have adequately compensated for potential generation outages arising from these instances of noncompliance during a declining system voltage/frequency event. No harm is known to have occurred as a result of this instance of non-compliance. NPCC considered the Entity's compliance history and determined there are no prior relevant instances of noncompliance.
Mitigation	To mitigate the noncompliance and prevent a recurrence, the Entity: 1. sent a communication to its Host BA regarding protection relaying enhancements implemented on two occasions (May 7, 2015 and September 12, 2016) for which it had failed to provide the required coordination. 2. implemented an internal control consisting of a NERC Management Checklist that instructs responsible staff to manually review, on a monthly basis, PRC-001 issues, such as changes/additions to protection equipment, and clearly highlights the need to coordinate such changes with both TOP and BA. It also includes how to coordinate those changes. 3. Implemented the use of automated preventive maintenance reminders for compliance tasks that will need to be completed by the 14th of each month.

NERC Noncompliance ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Mitigation Completion Date
NPCC2019021679	PRC-024-2	R1	Saranac Power Partners, L.P.	NCR07208	7/1/2016	2/14/2018	Off-site Audit	7/2/2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	During a Compliance Audit conducted from March 4, 2019 through April 3, 2019, NPCC determined that Saranac Power Partners, LP ("the Entity"), as a Generator Owner (GO), was in noncompliance with PRC-024-2 R1. The Entity failed to timely verify that frequency protection relays for their applicable three generating units were correctly set to not trip the generating units within the "no trip zone" of PRC-024-2 Attachment 1. Per the phased-in implementation plan of the Standard and Requirement, the above verification was required by July 1, 2016 for two of the Entity's generating units and by July 1, 2018 for the one remaining generating unit. This noncompliance started on July 1, 2016, when the Entity failed to perform the required frequency relay settings verification for two of its three generating units, and ended on February 14, 2018, when the Entity implemented frequency relay setting changes to bring these two units into compliance. On that same date, the Entity also completed frequency relay changes for its third generating unit, ahead of its July 1, 2018 deadline. The root cause of this instance of noncompliance consisted of the Entity underestimating the complexity of tests required to be completed within the timelines prescribed by the phased-in implementation plan for its applicable generating facilities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The Entity owns three generating units that are in scope of the standard: two Gas Turbines and one Steam Turbine, all of which are normally operated as a single Combined Cycle plant. The units are interconnected to one of the host TO's 115 kV substations. This noncompliance consisted of incorrect frequency protective relaying settings that would trip the Entity's three generating units within the "No Trip zone" of Attachment 1. In September 2016, the Entity's hired consultant performed an engineering assessment to determine specific changes needed to be implemented to existing frequency relays' settings. In order to achieve compliance, the Entity hired a second consultant to implement recommended changes to the tripping points of its generators' Over-Frequency relays (Device 81O), as summarized below: Generating unit / Non-compliant Setting (existing) / Compliant Setting (as implemented and tested) GT #1 / 60.5 Hz @ 0.4 sec. / 61.8 Hz @ 0.4682 sec GT #2 / 60.5 Hz @ 0.4 sec. / 61.8 Hz @ 0.4711 sec ST #1 / 60.5 Hz @ 0.45 sec. / 61.8 Hz @ 0.4703 sec The Entity's three generating units have a combined rated capacity of approximately 248 MW. The combined average annual capacity factors for these units have been 3.9% (in 2016), 2.7% (in 2017) and 3.1% (in 2018). By comparison, the Entity's Reliability Coordinator (NYISO) carries required Operating Reserves of approximately 1965 MW and could have adequately compensated for potential generation outages arising from these instances of noncompliance during a declining system frequency event during the noncompliance period. No harm is known to have occurred as a result of this instance of noncompliance. NPCC considered the Entity's compliance history and determined there are no prior relevant instances of noncompliance.
Mitigation	To mitigate the noncompliance and prevent a recurrence, the Entity: 1. implemented frequency relay setting changes to not trip its generating units within the "no trip zone" of PRC-024-2 Attachment 1 2. revised its main compliance document to highlight additional considerations affecting timely compliance with standards, which were not previously specifically included, such as phased implementation timeline requirements and third-party engineering support procurement lead-times. 3. implemented a new software tracking control that creates automatic reminders to responsible staff to ensure timely completion of compliance tasks.

NERC Noncompliance ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Mitigation Completion Date
NPCC2019021681	PRC-019-2	R1	Saranac Power Partners, L.P.	NCR07208	7/1/2016	10/17/2016	Off-site Audit	7/2/2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	During a Compliance Audit conducted from March 4, 2019 through April 3, 2019, NPCC determined that Saranac Power Partners, LP ("the Entity"), as a Generator Owner (GO), was in noncompliance with PRC-024-2 R1. The Entity failed to timely perform the coordination of voltage regulating system controls with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. Per the phased-in implementation plan of the Standard and Requirement, the above coordination was required by July 1, 2016 for two of the Entity's generating units and by July 1, 2018 for the one remaining generating unit. This noncompliance started on July 1, 2016, when the Entity failed to perform the required coordination of voltage regulating system controls for two of its three generating units, and ended on October 17, 2016, when the Entity completed coordination activities to bring these two units into compliance. On that same date, the Entity also completed coordination of voltage controls for its third generating unit, ahead of the July 1, 2018 deadline. The root cause of this noncompliance consisted of the Entity underestimating the complexity of tests required to be completed within the timelines prescribed by the phased-in implementation plan for its applicable generating facilities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The Entity owns three generating units that are in scope of the standard: two Gas Turbines and one Steam Turbine, all of which are normally operated as a single Combined Cycle plant. The units are interconnected to one of the host TO's 115 kV substations. The noncompliance consisted in the Entity's failure to complete coordination of voltage controls for its applicable generating units within the phase-in implementation timeline established by the standard. The coordination studies, when completed, did not recommend any changes to existing settings of voltage regulating system controls for any of the Entity's generating units. The Entity's three generating units have a combined rated capacity of 248 MW. The combined average annual capacity factors for these units have been 3.9% (in 2016), 2.7% (in 2017) and 3.1% (in 2018). By comparison, the Entity's Reliability Coordinator (NYISO) carries required Operating Reserves of approximately 1965 MW and could have adequately compensated for potential generation outages arising from these instances of noncompliance during a declining system voltage/frequency event during the noncompliance period. No harm is known to have occurred as a result of this instance of noncompliance. NPCC considered the Entity's compliance history and determined there are no prior relevant instances of noncompliance.
Mitigation	To mitigate the noncompliance and prevent a recurrence, the Entity: 1. completed coordination of voltage regulating system controls for its noncompliant generating units. 2. revised its main compliance document to highlight additional considerations affecting timely compliance with standards, which were not previously specifically included, such as phased implementation timeline requirements and third-party engineering support procurement lead-times. 3. implemented a new software tracking control that creates automatic reminders to responsible staff to ensure timely completion of compliance tasks.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020823	NUC-001-3	R6	Commonwealth Edison Company	NCR08013	9/24/2018	9/24/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 6, 2018, the entity submitted a Self-Report stating that, as a Distribution Provider and Transmission Owner (TO), it was in noncompliance with NUC-001-3 R6. As background, the entity, as a TO, has an NPIR obligation to notify a nuclear power plant when the remote end of a transmission line from the entity switchyard at the nuclear power plant is out of service. Notably, neighboring TOs own the remote ends of some of the lines from that entity switchyard. On September 24, 2018, the entity failed to notify the nuclear power plant that the remote end of a line was out of service. Specifically, to support planned work, a neighboring TO opened the remote end of a transmission line from the entity switchyard at the nuclear power plant. Due to unforeseen circumstances, the remote end outage needed to be expanded into the entity switchyard at the nuclear power plant. The neighboring TO contacted the nuclear power plant to inform it of this required expansion. The nuclear power plant then contacted the entity stating that it was unaware of the fact that the remote end of the line was open. The root cause of this noncompliance was an insufficient process to ensure that the proper notification was made to the nuclear power plant as required by the NPIR. In short, the control room operator responsible for making this notification missed it. This root cause involves the management practice of reliability quality management, which includes maintaining a system for deploying internal controls to ensure all requirements (including notifications) are met. This noncompliance started on September 24, 2018, when the entity was required to notify the nuclear power plant of the outage and ended later that same day when the nuclear power plant was made aware of the outage.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by a TO failing to coordinate an outage with the affected nuclear power plant is that it could result in a loss of situational awareness for the nuclear power plant and the loss of an opportunity for the nuclear power plant to perform a risk assessment before switching occurred. This risk was mitigated in this case by the following factors. First, although the nuclear power plant was unaware of the switching, the switching was still coordinated in a planned fashion between the entity, the neighboring TO, the entity's Transmission Operator (TOP), the neighboring TOP, and both applicable Reliability Coordinators, which reduced the risk of any adverse consequences. Second, during this outage, the nuclear power plant still had two sources of offsite power as required by the nuclear power plant's Technical Specification. No harm is known to have occurred. The entity has relevant compliance history. However, ReliabilityFirst determined that the entity's compliance history should not serve as a basis for applying a penalty because while the result of some of the prior noncompliances were arguably similar, the prior noncompliances arose from different causes.
Mitigation	To mitigate this noncompliance, the entity: 1) updated the energy management system screens with notification requirement reminders for lines associated with nuclear power plants and neighboring Transmission Owners; and 2) reviewed the event with the entity control room operators and issued a read-and-sign for the requirement to notify an affected nuclear power plan before planned work of an open-ended line condition, including tie-lines. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020824	PRC-023-3	R1	Commonwealth Edison Company	NCR08013	7/24/2015	10/7/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 7, 2018, the entity submitted a Self-Report stating that, as a Distribution Provider and Transmission Owner, it was in noncompliance with PRC-023-3 R1. On October 2, 2018, as part of a planned PRC-023 internal review, the entity discovered that it incorrectly configured a switch-onto-fault setting. Specifically, the entity configured the switch-onto-fault setting to operate at 106.7% of the line's Facility Rating, instead of 115% of the highest seasonal 15-minute Facility Rating of the circuit, as required by the Standard. The entity incorrectly configured this switch-onto-fault setting on July 24, 2015. The relay engineer performing the work chose not to follow normal company practices in this case because the relay was configured to protect a transmission line with non-standard configuration using a shunt inductor. The root cause of this noncompliance was an omission in the entity's relay setting guide, which in the event of configuring a line with non-standard a configuration, did not direct engineers to reevaluate loadability to ensure the line protection was set to operate above 115% of the highest seasonal 15-minute Facility Rating of the circuit. As a result, the relay engineer and peer checker did not reevaluate the loadability when the setting was issued. This root cause involves the management practice of asset and configuration management, which includes controlling changes to assets, and verification, in that the entity failed to verify the correctness of the relay setting. This noncompliance started on July 24, 2015, when the entity applied the 106.7% setting to the relay and ended on October 7, 2018, when the entity issued revised settings.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this noncompliance was that it could have resulted in an open transmission path due to this line's circuit breaker failing to remain closed during manual switching or following an automatic reclose attempt after a fault and subsequent loading conditions between 106.7% and 115% of the line's highest seasonal Facility Rating. This risk was mitigated in this case by the fact that, during the time of the noncompliance, the loading on this line never exceeded 60% of the line's highest seasonal Facility Rating. No harm is known to have occurred. The entity has relevant compliance history. However, ReliabilityFirst determined that the entity's compliance history should not serve as a basis for applying a penalty because while the result of some of the prior noncompliances were arguably similar, the prior noncompliances arose from different causes.
Mitigation	To mitigate this noncompliance, the entity: 1) revised settings to reconcile switch-onto-fault setting deviation for specified instance reported; 2) communicated to its relay setting engineers that Switch onto Fault settings must conform to the NERC PRC-023 Standard; 3) created PRC-023 settings/loadability awareness that is incorporated into the relay setting engineering onboarding packet and communicated the awareness material to relay setting engineers; 4) created a General Settings Design Document to address general considerations to take when creating relay settings for switch-onto-fault as applicable to PRC-023 conformance; 5) performed an analysis of implemented Switch onto Fault supervision or initiation method for lines in-scope of PRC-023; and 6) revised AM-CE-P014 Self Check and Independent Review of Design Packages, Section 3.5, and Attachment AM-CE-P014-5 T&S Relay Engineer Checklist to account for applicable PRC-023 loadability requirements.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020673	MOD-026-1	R2	Delaware City Refining Company LLC	NCR11173	7/1/2018	9/7/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 7, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-026-1 R2. The entity was unable to complete generator excitation system testing and model verification by the July 1, 2018 deadline. The entity was required to contract with a specialized engineering firm to conduct this work because it lacks the necessary expertise internally. Due to the increased demand on the contract firm, the work was not completed on time. The contract firm completed the work on September 7, 2018. The root cause of this noncompliance was the failure of the entity to anticipate, and appropriately plan for, the high demand for the specialized engineering resources needed. This root cause involves the management practices of work management and external interdependencies. This noncompliance started on July 1, 2018, when the entity was required to comply with MOD-026-1 R2 and ended on September 7, 2018, when the entity completed the requisite testing and model verification.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by this noncompliance arises from using outdated or incorrect information regarding the generator excitation control system or plant volt/var control function behavior in dynamic simulations. That can lead to Transmission Planners operating the BPS with inaccurate information. This risk was mitigated by the following factors. First, the entity completed the work just over one month late, which minimized the amount of time that models could have been affected. Second, the entity's generator excitation system was already modeled in the system and the analysis determined that only one parameter had to be changed (i.e., the Ka was changed from 4.5 to 3.54 to better match the modeled response with measured waveforms). Third, the facility has a capacity factor of 38% and provides approximately 83 MVA to the directly connected oil refinery and approximately 60 MVA to the BPS. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) documented that the field testing, data analysis, and generator excitation model recommendations were completed and a report was submitted to the Transmission Planner; and 2) set the action date in the entity's NERC Compliance Tracking System for January 1, 2028 to ensure that there is enough time to complete the specialized engineering tasks of field testing, data analysis and model revision recommendations ahead of the due date. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020674	MOD-027-1	R2	Delaware City Refining Company LLC	NCR11173	7/1/2018	9/7/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 7, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-027-1 R2. The entity was unable to complete generator excitation system testing and model verification by the July 1, 2018 deadline. The entity was required to contract with a specialized engineering firm to conduct this work because it lacks the necessary expertise internally. Due to the increased demand on the contract firm, the work was not completed on time. The contract firm completed the work on September 7, 2018. The root cause of this noncompliance was the failure of the entity to anticipate, and appropriately plan for, the high demand for the specialized engineering resources needed. This root cause involves the management practices of work management and external interdependencies. This noncompliance started on July 1, 2018, when the entity was required to comply with MOD-027-1 R2 and ended on September 7, 2018, when the entity completed the work.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by this noncompliance arises by allowing dynamic simulations that assess BPS reliability to inaccurately represent generator unit real power response to system frequency variations. That can lead to Transmission Planners operating the BPS with inaccurate information. This risk was mitigated by the following factors. First, the entity completed the work just over one month late, which minimized the amount of time that models could have been affected. Second, the entity's generator excitation system was already modeled in the system and the analysis determined that only one parameter had to be changed (i.e., the Ka was changed from 4.5 to 3.54 to better match the modeled response with measured waveforms). Third, the facility has a capacity factor of 38% and provides approximately 83 MVA to the directly connected oil refinery and approximately 60 MVA to the BPS. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) documented that the field testing, data analysis, and turbine/governor control system model recommendations were completed and a report was submitted to the Transmission Planner; and 2) set the action date in the entity's NERC Compliance Tracking System for January 1, 2028 to ensure that there is enough time to complete the specialized engineering tasks of field testing, data analysis and model recommendations ahead of the due date. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020792	VAR-002-4	R2	FirstEnergy Nuclear as agent for etc.	NCR11316	2/16/2017	8/5/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 3, 2018, the entity submitted a Self-Report stating that, as a Generator Operator (GO), it was in noncompliance with VAR-002-4 R2. The entity, as a GO, is required via VAR-002-4 R2 to comply with PJM's (Transmission Operator (TOP)) conditions of notification for deviations from the voltage or reactive power schedule provided by PJM. The entity is required to maintain and adhere to its PJM assigned voltage schedule and to notify the Transmission Local Control Center when they are outside of the specified voltage schedule limits continuously for thirty minutes. In the initial Self-Report, the entity identified 56 instances where the entity deviated from its voltage schedule and failed to notify the Transmission Local Control Center within the thirty-minute notification requirement. During the course of mitigating this noncompliance, the entity performed an extent of condition review to determine if there were any additional instances where the entity did not adhere to its voltage schedule. This additional analysis resulted in a new total of 117 instances. (Some of the increase is that the follow-up review identified multiple occurrences of not meeting the voltage schedule on the same day that were previously reported as a single occurrence. The follow-up evaluation also considered if entity units were at minimum and maximum MVAR capability which changed the times and dates of the original 56 instances. PJM notification requirements exempt the GO from notification if the unit is at maximum or minimum D-Curve limits while trying to maintain voltage schedule and this data point was not previously considered in the initial review.) 116 instances occurred at the entity's Beaver Valley Units and one instance occurred at the entity's Perry Generation Unit. The entity units were outside their voltage schedule limit on average by 1.52 kV (0.43%) and all instances deviated from the voltage schedule by less than 5kV (less than 2%) (The longest duration for a deviation was approximately 6.5 hours. A majority of the deviations occurred for less than an hour.): (a) There was a total of eight instances that were outside their voltage schedule limit by 0.75% or greater (with a maximum deviation of 1.32%). (b) There were 22 instances outside their voltage schedule limit by between 0.50% and 0.75%. (c) There were 87 instances outside their voltage schedule limit by less than 0.50%. The root cause of the various instances comprising this noncompliance was a poorly drafted "Voltage Schedule Guidance" procedure which did not provide a clear reference to VAR-002 notification expectations. That led to confusion on voltage schedule responsibilities. This noncompliance involves the management practices of work management and grid operations. Work management is involved because the entity relied on a faulty procedure to manage notifications to its Transmission Operator, resulting in incomplete information flowing between the entity as a GO and PJM as a TOP. Grid operations management is involved because the entity's failure to notify the TOP of voltages outside of the voltage schedule limits created a breakdown in monitoring operations and maintaining situational awareness. The noncompliance began on February 16, 2017, the first date the entity deviated from its voltage schedule and ended on August 5, 2018, the last date the entity deviated from its voltage schedule.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is allowing voltage schedule deviations at levels detrimental to the bulk power system's (BPS) voltage level without the TOP having knowledge, which could result in harm to the BPS. The risk is minimized because all instances of noncompliance occurred during off-peak hours when the maximum voltage limit changed from 355 kV to 350 kV. Further minimizing the risk, all 117 instances deviated from the voltage schedule by less than 5kV (less than 2%). Lastly, the average deviation was just 1.52 kV (0.43%). No harm is known to have occurred. The entity has relevant compliance history. However, ReliabilityFirst determined that the entity's compliance history should not serve as a basis for applying a penalty because while the result of the prior noncompliance was arguably similar, the prior noncompliance arose from a different root cause.
Mitigation	To mitigate this noncompliance, the entity: 1) installed a Generation Management System alarm using the thirty-minute rolling average. This enhancement will prompt the Generator Operator to contact the Beaver Valley plant to assist with timely notification to the Transmission Local Control Center (LCC); 2) changed the Beaver Valley night, weekend, and holiday high voltage schedule limit from 350kV to 353kV. The voltage limits were overly restrictive, and the expansion of the voltage schedule limit reduced the number of notifications required to the Transmission LCC when Beaver Valley is outside of its voltage schedule; and 3) updated the Beaver Valley Voltage Schedule Guidance procedure to add a reference to VAR-002 and to clarify notification expectations with the Transmission LCC. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020030	MOD-026-1	R2	Interpower/Ahlcon Partners Limited Partnership	NCR11335	7/1/2018	4/26/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On July 9, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-026-1 R2. On April 2018, during a routine review of NERC Standards, the entity discovered that it would not be able to complete testing for MOD-026-1 and subsequent submittal of test data by the required completion date, July 1, 2018. Attempts to meet this deadline were not successful due to logistical and system restraints, including lack of available vendors to perform the requisite testing and the limited timeframe to coordinate the testing. The root cause of this noncompliance was the entity's lack of awareness related to the impending deadline combined with logistical constraints the entity encountered when attempting to hire a third-party testing company. This root cause involved the management practices of work management and workforce management, which includes providing training, education, and awareness to employees. This noncompliance started on July 1, 2018, when the entity was required to comply with MOD-026-1 R2 and ended on April 26, 2019, when the entity completed its Mitigation Activities.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by this noncompliance arises from using outdated or incorrect information regarding the generator excitation control system or plant voltage/var control function behavior in dynamic simulations that can lead to Transmission Planners operating the BPS with inaccurate information. The risk was mitigated in this case by the following factors. First, the type of information at issue here does not change very often. In fact, the relevant data for this particular plant has been the same since the plant began operations. Second, the plant has never had any issues relating to generation excitation control or plant voltage/var systems. Third, the facility is a waste coal burning plant rated at 131 MVA and connected to the Bulk Electric System at 115kV. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) ensured a third party testing company completed the required testing; and 2) created a monthly reminder to monitor upcoming NERC Standards requirements.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020759	PRC-005-6	R3	Northampton Generating Company, LP	NCR00852	4/1/2017	10/10/2018	Spot Check	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 21, 2018, ReliabilityFirst determined that the entity, as a Generator Owner, was in noncompliance with PRC-005-6 R3 identified during a Spot Check conducted from October 29, 2018 through November 20, 2018. ReliabilityFirst determined that the entity failed to complete all of the 18 calendar month maintenance activities for its batteries pursuant to Table 1-4(a) by the April 1, 2017 implementation date. ReliabilityFirst noted that the entity had successfully and timely performed the 4 calendar month maintenance activities on its batteries. However, the entity completed the 18 calendar month maintenance activities on October 10, 2018. The root cause of this noncompliance was an insufficient process for tracking when certain maintenance activities were due and for ensuring that the proper maintenance actions were performed. This root cause involves the management practices of external interdependencies, in that the entity utilized a vendor to conduct the maintenance, reliability quality management, which includes maintaining a system for deploying internal controls, and grid maintenance. This noncompliance started on April 1, 2017, when the entity was required to have completed the 18 calendar month maintenance activities and ended on October 10, 2018, when the entity completed those maintenance activities.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by failing to perform the required maintenance activities on Protection Systems within the required time intervals is that it may result in a failure of the Protection System to operate as expected or required, which may result in reduced reliability of the BPS. This risk was mitigated in this case by the following factors. First, although the entity failed to complete the 18 calendar month maintenance activities, it had successfully completed the 4 calendar month maintenance activities. Second, when the entity subsequently performed the 18 calendar month maintenance activities, no issues were identified. Third, this unit is not a Blackstart Resource, so its potential loss would not impact a system restoration plan. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) completed eighteen month maintenance activities; 2) installed new batteries; 3) reviewed with the technicians the requirements and provided a sign off training sheet; and 4) purchased a battery monitoring system and verified alarm pathways that will ensure systems components are monitored and maintained to the point of obtaining exemption status of the maintenance requirements. The entity also updated its procedure to reflect these changes. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020822	COM-002-4	R5	PJM Interconnection, LLC	NCR00879	7/18/2018	7/18/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 6, 2018, the entity submitted a Self-Report stating that, as a Reliability Coordinator, it was in noncompliance with COM-002-4 R5. On July 18, 2018, a 138 kV bus in American Electric Power's (AEP) service territory tripped, thereby creating a radial load pocket and severe low voltages in the area. The entity and AEP operators had multiple conversations to discuss the low voltage conditions, including discussions involving switching actions to help alleviate the conditions in conjunction with a load shedding plan. The entity operator indicated that AEP would have to shed load, but the entity operator failed to comply with COM-002-4 R5. Specifically, the entity operator failed to utilize appropriate three-part communication (i.e., issue the Operating Instruction, wait for the receiver to repeat the Operating Instruction, and confirm the receiver's response if the repeated information is correct). The root cause of this noncompliance was a lack of sufficient training and preparation, as infrequently performed steps (i.e., communications during unplanned switching to remediate emergency conditions) were performed incorrectly. This noncompliance involves the management practice of workforce management. An entity should train staff, which can impart skills and knowledge to enable staff to effectively perform specific reliability and resilience functions. This noncompliance started on July 18, 2018, when the entity failed to comply with the communication requirements set forth in COM-002-4 R5 and ended that same day when communications with AEP regarding the event ceased.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS) based on the following factors. A violation of COM-002-4 R5 has the potential to adversely affect the reliable operation of the BPS because there would be an increased likelihood of miscommunication and corresponding action or inaction that is incorrect. In this case, that risk was reduced by the following facts. The entity and AEP operators had several conversations prior to the load shed instruction and clearly identified a load shed plan and the breakers that would need to be opened. And, as demonstrated by the voice transcript of communications regarding the instruction, both parties understood the next steps that needed to be executed. The entity and AEP shed sufficient load to alleviate all low voltage conditions in the area. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) conducted system operator training to review the AEP load shed event; and 2) delivered a class on effective communications and the importance of three-part communication, as part of the normal operator cycle training. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020845	MOD-032-1	R2	Rocky Road Power, LLC	NCR03009	6/16/2018	6/25/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 13, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-032-1 R2. The entity was required to submit its MOD-032 data to PJM Interconnection, LLC (PJM) on or before June 15, 2018, but it did not submit the data until June 25, 2018. A new individual was responsible for reporting to PJM but was not fully aware of the reporting procedures and deadlines. The noncompliance was discovered when a compliance manager was following up to ensure that all necessary data was submitted to PJM. The root cause of this noncompliance was the entity's mismanagement of staff turnover. The entity did not adequately train the person who had recently transitioned into the new role and was unfamiliar with reporting procedures and deadlines. This noncompliance involves the management practice of workforce management. Workforce management includes the implementation of training programs and internal controls designed to ensure adequate performance of reliability and resilience functions. This noncompliance started on June 16, 2018, after the entity failed to submit its MOD-032 data to PJM in a timely manner and ended on June 25, 2018, when the entity submitted the data.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System based on the following factors. An entity's failure to submit MOD-032 data to its Transmission Planner (TP) and Planning Coordinator (PC) by the submission deadline could prohibit the TP and PC developing accurate models and analyzing the reliability of the interconnected system. The risk was mitigated by the following facts. PJM already possessed modeling information for the plant, which the entity had submitted in June, 2017. Further, this issue was short in duration (i.e., the data was submitted ten days late) and quickly self-identified and corrected by the entity. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) updated the procedure covering required submissions; 2) finalized the NERC Management Checklist to include data submittal dates specific to the site; 3) designated an individual to be responsible for monitoring and submission of MOD-032 data; 4) trained staff responsible for submission on the updated procedure; and 5) created recurring work management work orders for submission of required MOD-032 data.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020847	PRC-005-6	R3	U.S. Department of Energy	NCR04167	10/1/2018	11/28/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 12, 2018, the entity submitted a Self-Report stating that, as a Transmission Owner, it was in noncompliance with PRC-005-6 R3. During a review conducted on November 20, 2018 of the entity's PRC-005-6 Protection System Maintenance Program (PSMP), the entity identified that two station service batteries were not properly maintained in accordance with Table 1-4(a) of NERC PRC-005-6. Table 1-4(a) requires Vented Lead Acid (VLA) station service batteries to have "terminal connection resistance" and "intercell or unit-to-unit connection resistance" verified at least once every 18 calendar months. The entity concluded that the last completion of the resistance checks on the two station service batteries was on March 10, 2017 and that the entity had not completed resistance checks by the next required completion date of September 30, 2018. The entity timely performed all other activities listed in Table 1-4(a) of NERC PRC-005-6. After discovering this noncompliance, the entity promptly performed the overdue resistance checks on November 28, 2018. A cause of this noncompliance is that this maintenance activity (completing resistance checks) was previously performed as corrective maintenance when the requirements of PRC-005-6 became effective and this activity was not included in the Computerized Maintenance Management System (SOMAX) to notify maintenance personnel when the activity was again due. Entity personnel had identified that this activity needed to be included in SOMAX as a required maintenance activity, but the process to add this maintenance activity to SOMAX was inadvertently not completed. The failure to add this maintenance activity into the entity's maintenance management system is the root cause of this noncompliance. This noncompliance involves the management practices of implementation and verification because the entity did not implement or verify that it had implemented this required maintenance activity in its maintenance management system. This noncompliance started on October 1, 2018, when the entity was required to complete the 18 calendar month resistance checks and ended on November 28, 2018, when the entity completed the overdue resistance checks.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by this noncompliance is allowing important Protection System devices (VLA batteries) to remain unmaintained and untested which could have resulted in failure of the breakers to operate during a fault. The risk is minimized because of the less than two months duration of this noncompliance. Additionally, the entity has two redundant battery systems and both would have to fail under a double contingency in order to cause a significant impact to the BPS. The entity also timely completed all other required maintenance activities for these batteries for the duration of the noncompliance. Lastly, ReliabilityFirst notes that when the entity performed the overdue resistance checks, those checks confirmed the battery system resistances measurements were all within the normal range. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) scheduled and performed the delinquent maintenance activity; 2) added the maintenance activity to SOMAX; 3) performed an extent of condition to determine if any other required maintenance activities are not included in SOMAX. This extent of condition determined that one activity (for the annual battery maintenance) was not listed in SOMAX; 4) revised the process for modifying NERC related maintenance activities in SOMAX such that the NERC Compliance team has oversight to any changes made to the NERC related items; and 5) updated the entity Protection System Maintenance Program (PSMP) to include the newly identified maintenance activity information. This activity also required updating the internal Engineer Evaluation which drives what items to include in the PSMP. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019020888	VAR-002-4.1	R3	Wisconsin Electric Power Company	NCR00951	9/27/2018	9/28/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 21, 2018, the entity submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with VAR-002-4.1 R3. At 11:55 A.M. on September 27, 2018, the entity enabled a new Power System Stabilizer (PSS) on Valley Power Plant Unit 1 while the unit was online and undergoing commission testing for upgraded turbine controls and excitation systems. The PSS remained enabled until 9:32 A.M. on September 28, 2018 when Unit 1 went offline for minor repairs. The entity, however, failed to notify the Transmission Operator (TOP) of this initial change in status of the PSS within 30 minutes of the status change as required by VAR-002-4.1 R3. (The entity operating procedure for communicating Automatic Voltage Regulator (AVR) and PSS status change is PG-522, Generator Voltage and Reactive Power Control.) The PSS addition to Valley Power Plant Unit 1 was part of a larger plant modification that upgraded turbine controls and excitation systems. The facility modification process required that a change to these systems would result in a notification to the system protection engineer and NERC Compliance Coordinator. There was a miscommunication between the Project Manager and the system protection engineer/NERC compliance coordinator regarding the PSS installation. The impact of the PSS installation on NERC compliance was not realized in the project planning and plant modification phases which caused this noncompliance. Additionally, the PSS status alarms had not been set up in the Supervisory Control and Data Acquisition system so the entity System Reliability Supervisors did not receive an alarm when the PSS status changed. The System Reliability Supervisors are tasked with making notifications to the TOP for status changes such as enabling the PSS. The entity discovered this noncompliance in November 2018 when an entity employee performed an annual review of VAR-002-4.1 compliance. This included reviewing applicable electronic logs to ensure ongoing NERC compliance. This noncompliance involves the management practices of asset and configuration management, workforce management, and reliability quality management. A contributing cause of this noncompliance was ineffective internal communications between the project manager and the entity's NERC Compliance Coordinator regarding Unit 1 and plant modification. The root cause was ineffective training as the impacts of the PSS installation were not effectively communicated to the NERC Compliance Coordinator. This noncompliance started on September 27, 2018, at 11:55 AM when the entity failed to notify the Transmission Operator of the active PSS and ended on September 28, 2018, at 9:32 AM when Unit 1 went offline for minor repairs. (The PSS was enabled for approximately 21 hours and 37 minutes without notifying the TOP.)
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based (BPS) on the following factors. The risk posed by allowing PSS changes to occur without timely informing the TOP is that the TOP could make decisions which impact the BPS based on faulty or incomplete information. The risk is minimized because Unit 1's Automatic Voltage Regulator was operating and controlling voltage for the duration of the noncompliance. The unit also monitored and maintained its voltage schedule for the entire noncompliance. Lastly, the addition of the PSS to Unit 1 was done during a plant modification to upgrade the turbine controls and excitation systems which increased the overall reliability of the unit and of the BPS. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) implemented a Supervisory Control and Data Acquisition alarm for the VAPP Unit 1 PSS status; 2) retrained applicable operators and engineers on procedures PG-705, Facility Modification Request and PG-522, Generator Voltage and Reactive Power Control; and 3) updated the Power Generation (PG) Project Authorization Request process and the PG facility modification process to require a NERC review.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2019020959	FAC-003-3	R3	Wisconsin Electric Power Company	NCR00951	January 1, 2015	March 7, 2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On January 11, 2019, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with FAC-003-3 R3. During the implementation phase of FAC-003-3 in 2014, the entity erroneously interpreted and applied FAC-003-3 in concluding that the entity did not own or operate transmission lines to which FAC-003-3 applied. However, in November 2018, internal reviews performed by the entity determined that FAC-003 was applicable to generator lead lines for Oak Creek Power Plant (OCPP) Units 6, 7, and 8, (The generating capacity of OCPP Units 6, 7, and 8 is: Unit 6: 264 megawatts, Unit 7: 298 megawatts, and Unit 8: 312 megawatts.) as well as Elm Road Generating Station (ERGS) Units 1 and 2. (The generating capacity of ERGS Units 1 and 2 is: Unit 1 634 megawatts and Unit 2 634 megawatts.) The entity's original determination of non-applicability was focused on Section 6, Background, which provides that vegetation management "does not apply to underground lines, submarine lines, or line sections inside an electric station boundary." All line sections of the OCPP lead lines and ERGS lead lines are inside an electric station boundary, and were within the "clear line of sight." The entity then determined based on these facts that the lines were outside of the scope of FAC-003-3. This interpretation was incorrect. Upon review in 2018 and in preparation for an O&P Compliance Audit by ReliabilityFirst, the entity requested an interpretation of FAC-003-4 to validate its application. ReliabilityFirst determined that both the "inside electric station boundary" and "clear line of sight" carve-outs could not be used as exclusions here. Those carve outs were not applicable because the line is applicable under FAC-003-3 because it is an overhead transmission line that does not have a clear line of sight from the generating station switchyard fence to the point of interconnection. (*See* Section 4, Applicability) The entity then applied ReliabilityFirst's guidance regarding FAC-003 and discovered the OCPP and ERGS lines were not in compliance with FAC-003. Due to the original misinterpretation, the entity neither established a qualifying vegetation management process nor inspected the applicable OCPP and ERGS lines as required by FAC-003-3 R3 and R6. The root cause of this noncompliance was a lack of requisite training and knowledgeable staff to effectively interpret FAC-003 requirements. This noncompliance involves the management practices of grid maintenance and workforce management. Grid maintenance management is involved because this noncompliance involves the failure to implement a process resulting in the risk that the entity would not perform grid maintenance in a timely or effective fashion. Workforce management is involved because this noncompliance results from the entity's failure to train employees on how to effectively interpret FAC-003 requirements. This noncompliance started on January 1, 2015, when the entity was required to comply with FAC-003-3 R3 and ended on March 7, 2019, when the entity completed its Mitigating Activities by performing a vegetation inspection of 100% of the applicable OCPP and ERGS lines.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is the failure to implement a process to manage vegetation growth in transmission line rights-of-way could cause potential vegetation contacts. The risk is minimized because the lines involved in this instance of noncompliance resided entirely within the Oak Creek campus within an electric station boundary fence. This lowers the risk because it is a short span of line that is also easier to monitor as the utility complex is staffed continuously. Further, the lines involved are only exposed to a limited number of trees in the vicinity as most nearby trees were removed in 2016. (At time of initial evaluation, the WEC Energy Group Subject Matter Expert identified trees near sections of the ERGS Units 1 & 2 lines. Those trees were removed in 2016. Sections under the OCPP Units 6, 7 & 8 lines are in part over a paved parking lot. The lead lines extend over grass, parking lots, railroad tracks, and low growing plants. The terrain that the lead lines traverse contains a bluff with a steep slope. The bluff is designed with prairie grass with deep rooted sumac to minimize erosion and maintain structure. Lawn care and weed control is managed under contract.) Plant management monitors and actively manages tree growth and removal on an ongoing basis. Finally, a vegetation inspection of the involved OCPP and ERGS lines following the noncompliance found that no encroachment into the MVCD exists. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) the entity updated PG30-23 Vegetation Management procedure to include the now applicable OCPP and ERGS lines; and 2) performed a vegetation inspection of 100% of the applicable OCPP and ERGS lines. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2016016086	PRC-005-2(i)	R3	Duke Energy Progress, LLC (DEP)	NCR01298	01/01/2016	05/18/2016	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 1, 2016, Duke Energy Florida (DEF) submitted a Self-Report to Duke Energy Progress (DEP) stating that, as a Transmission Operator (TO), DEF was in noncompliance with PRC-005-2(i) R3. Under an existing multi-regional registered entity agreement, DEP submitted the Self-Report to SERC. DEF did not conduct a required maintenance activity within the defined interval for one battery. On August 23, 2016, during a normal review of maintenance documentation to verify compliance, a Duke compliance analyst questioned the test results from a 230 kV substation. The analyst contacted the electrician that performed the work and discovered a battery type discrepancy between the maintenance database and the battery deployed. In January 2015, DEF replaced a vented lead-acid battery with a sealed valve-regulated lead-acid (VRLA) battery, but did not update the database. At the time of installation, DEF did not follow its established process to complete an equipment change request and did not change the battery type. PRC-005-2(i), Table 1-4(b), requires internal resistance measurement, every six months, for sealed VRLA batteries, whereas Table 1-4(a), requires 18-month testing for vented lead-acid batteries. Generally, DEF performed battery impedance tests to meet those requirements. On June 24, 2015, DEF performed scheduled annual maintenance on the battery, which included an impedance test. However, DEF did not perform the required six month impedance test by the end of December 2015. This noncompliance started on January 1, 2016, when DEF was required to complete the required battery maintenance for the one battery, and ended on May 18, 2016, when DEF performed the maintenance activity on the battery. The root cause of this noncompliance was a deficient process and lack of an internal control to ensure adherence to the process. The electrician who replaced the battery did not complete the equipment change request form or update the management maintenance system (MMS) database to reflect the change per DEF's process. DEF's process did not require a review after changes were implemented to ensure that equipment change request form were completed and updates were made to the MMS database as required by the process.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk posed by Duke's failure to perform timely battery maintenance was the potential that the batteries would not perform protective functions or normal operating actions when needed. However, the noncompliance involves only one substation battery, and the required testing was late by less than five months. DEF conducted quarterly inspections of all applicable batteries at the Griffin 230kV substation, as well as monthly visual substation inspections, to identify potential issues. DEF did not identify any potential issues during those inspections for the duration of the noncompliance. Moreover, when DEF discovered the noncompliance and performed the impedance test of the replacement battery, it did not identify any battery decay. No harm is known to have occurred. DEF and its affiliates, Duke Energy Carolinas, LLC (DEC), and Duke Energy Progress, LLC (DEP), has relevant compliance history. DEF's relevant prior noncompliance with PRC-005 includes FRCC2013012446; FRCC2015015063; and SERC2015015248. In FRCC2013012446 (PRC-005-1 R2), DEF did not have maintenance and testing evidence for one pair of substation transmission bus relays because they were incorrectly listed as distribution relays in the MMS database. Therefore, the relays were not being tracked for scheduled maintenance. FRCC2015015063 (PRC-005-1.1b R2) involved three instances of noncompliance. In the first instance, DEF replaced the primary Frequency Shift Keying (FSK) blocking carrier and updated the MMS database to reflect the change; however, during the update, the secondary FSK blocking carrier was mistakenly removed from the MMS database. As a result, preventative maintenance work orders were not generated for both blocking carriers, which resulted in the failure to test the carriers in accordance with the standard. In the second instance, DEF failed to maintain complete battery maintenance records for four substations. In the third instance, DEF replaced two battery banks in a substation but they were not updated in the MMS database for tracking maintenance due dates. In SERC2015015248 (PRC-005-2 R3), DEF performed annual battery maintenance of a substation on February 19, 2015; however, DEF did not maintain sufficient evidence of the maintenance. Specifically, DEF was unable to provide evidence for verifying float voltage, cell condition, and condition of battery racks for one battery. Additionally, some battery maintenance forms were missing header information identifying the battery that was maintained. DEC's relevant prior noncompliance with PRC-005-1 R2 includes SERC201000544 where it failed to test approximately 1.9% of its devices within the defined interval. DEP's relevant prior noncompliance with PRC-005-1b R2 includes SERC200900306 (PRC-005-1 R2), SERC200900412 (PRC-005-1 R1), SERC2011006760 (PRC-005-1 R2), SERC2013012434 (PRC-005-1b R2), and SERC2014014141. SERC200900306 involved two Coupling-Capacitor Voltage Transformers at a 115 KV substation where DEP failed to maintain within the defined interval. In SERC200900412 (PRC-005-1b R2). DEP failed to document a basis for battery maintenance and testing intervals consistent with its authorized and implemented intervals. In SERC2011006760, there were no documented maintenance and test records for .64% of Protection System Devices. SERC2013012434 involved delayed testing of an associated communication system due to work on the terminal of an adjacent Transmission Owner. In SERC2014014141 battery maintenance at one power plant was scheduled and performed before the quarter in which it should have been performed. Duke Energy Corporation does not have a relevant compliance history.

	SERC reviewed the above compliance history of DEF and its affiliates and determined that the instant noncompliance is appropriate for Compliance Exception treatment for the following reasons. The violation history does not include any recent instances of noncompliance, which could suggest a programmatic deficiency. Additionally, the root cause of the current noncompliance is different than the root causes of the prior instances of noncompliance. Moreover, each Duke Energy affiliate is responsible for its own maintenance and testing program and the completed mitigation plans would not have addressed the current issue. The current noncompliance posed only minimal risk, and the entity quickly identified and corrected the current noncompliance. Therefore, SERC did not consider the violation history as aggravating circumstances that would require an elevated disposition method.
Mitigation	To mitigate this issue, DEF: 1) updated the maintenance database with the correct battery type; 2) communicated to the Construction Maintenance and Vegetation departments, across all Duke jurisdictions, their responsibility to complete equipment change request forms for all Units of Property within 14 days of the completion of the work; 3) completed work management to include equipment change request data form with work packages for any maintenance related NERC Units of Proper replacement; 4) updated the Asset Management database with equipment changes and maintenance to ensure triggers/intervals are set up for all Projects, or Emergent Capital Projects; 5) notify stakeholders when Project and/or Emergent Capital Work has been placed in service; 6) conducted a survey of substation battery types to ensure they match the battery types listed in the MMS database; and 7) revised its process and implemented an internal control, specifically, implemented ongoing monthly check of battery replacement work orders, which will allow DEF to identify new batteries installed before they need to be inspected every 4 calendar months.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018740	PRC-005-6	R3	Alamo 6, LLC (ALAMO 6) (the "Entity")	NCR11641	10/01/2016	03/23/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 1, 2017, the Entity submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with PRC-005-6 R3. Specifically, the Entity failed to timely perform maintenance activities with a maximum maintenance interval of four months for one vented lead-acid (VLA) battery bank. Subsequently, on April 23, 2018, the Entity identified an additional instance of noncompliance regarding PRC-005-6 R3. In this second instance, the Entity failed to perform maintenance activities with a maximum maintenance interval of four months for two communications systems devices. Regarding the Entity's VLA battery bank, the Entity stated that it discovered in February 2017 that the maintenance activities with a maximum maintenance interval of four months had not been performed. The Entity indicated that the first four-month interval for the VLA battery bank should have been performed before October 1, 2016, but it was not performed until March 14, 2017. In addition, every four months, a GO must verify that its communications systems devices are functional, which the Entity performs by recording a "lamp light test." However, for the maintenance interval ending in November 2017, the Entity's quarterly maintenance records do not include documentation of the results of the "lamp light test." The Entity performed and documented the maintenance activities at issue on March 23, 2018. Therefore, the duration of this second instance was from December 1, 2017, to March 23, 2018. For the instance involving the Entity's VLA battery bank, the root cause is that the previous owner of the Entity failed to perform the maintenance activities at issue prior to the current owner's acquisition of the Entity. The change in ownership occurred in January 2017, and the noncompliance was discovered on February 2, 2017. For the instance involving the two communications systems devices, the root cause is that the Entity did not have a sufficient process to ensure its maintenance contractor documented the completion of the maintenance activities at issue. Specifically, for the November 2017 maintenance interval, the Entity's contractor used a document form that did not include a field to record the "lamp light test," but the correct form was used for the maintenance intervals immediately prior to and after the noncompliance. This noncompliance started on October 1, 2016, which is the first day after the first four-month interval for the VLA battery bank was due, and ended on March 23, 2018, when the Entity documented the completion of the maintenance activities at issue for the two communications systems devices.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. This risk posed by this issue is that the VLA battery bank and communications systems devices at issue would not function as intended. However, the risk posed by this issue is reduced by several factors. First, the VLA battery bank and communications systems devices at issue comprise approximately 6% of the 52 Protection System devices associated with the generator at issue. Second, the Entity did not identify any issues with the VLA battery bank and communications systems devices when it performed the required maintenance activities. Third, the duration of each instance of noncompliance was short, with each instance lasting less than six months. Finally, the generator at issue is relatively small, comprising a solar generating unit with a nameplate rating of 116 MVA. No harm is known to have occurred. Texas RE considered the Entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the Entity: 1) performed the maintenance activities at issue for the VLA battery bank and the two communications systems devices; 2) adopted a new Protection System Maintenance Program following the completion of the change in control of the Entity; 3) increased the frequency of the Entity's quarterly maintenance activities so that they would be performed monthly, and conducted a meeting with compliance personnel to discuss the change in frequency; and 4) provided the Entity's maintenance contractor with instructions to use the appropriate form for the maintenance activities at issue. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018018982	VAR-002-4	R3	Barney M Davis, LP (BMDLP) (the “Entity”)	NCR04009	07/02/2017	11/30/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 11, 2018, the Entity submitted a Self-Report under an existing multi-region registered entity agreement stating that, as a Generator Operator (GOP), it was in noncompliance with VAR-002-4 R2. Specifically, the Entity failed to notify its associated Transmission Operator (TOP) of a status change on the power system stabilizer (PSS) within 30 minutes of the change. During a review of lessons learned for the Talen fleet for VAR-002-4.1 and a best practice review of automatic voltage regulator (AVR) alarms, the Entity identified 15 instances of noncompliance with VAR-002-4 R3, between July 2, 2017 and November 30, 2017. The longest period of time the Entity failed to notify its TOP of a PSS status change was 2.5 hours. The root cause of this noncompliance was a lack of internal controls to properly set the activation of the PSS. The PSS settings at the facility were appropriate for a 2 x 1 operation; however, the PSS dropout and return cycles were occurring in the 1 x 1 configuration without operation command or awareness. A contributing root cause was a lack of internal controls for notifications when there is a change in PSS status. The Entity determined that there was not a “PSS Not Active” alarm to alert the operator when a PSS status changed. This noncompliance started on July 2, 2017, 31 minutes after there was a change in the PSS status for the facility that was not reported to the TOP, and ended on November 30, 2017, when following the final instance of noncompliance the PSS was restored to active status to match the PSS status provided to its TOP.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, during the periods when the Facility was operating with the PSS Not Active for steam turbine 2, there were no known system perturbations, the Facility operated within its operating limits, and the Facility maintained the TOP’s voltage schedule. Second, the automatic voltage regulator (AVR) remained in service throughout each of the 15 instances. Third, there were no trips or facilities outages during the 15 instances. No harm is known to have occurred. Texas RE considered the Entity’s compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the Entity: 1) restored the PSS to active status to match the PSS status provided to its TOP; 2) revised the PSS activation and de-activation set points; 3) reviewed 2 x 1 combined cycle operation and gas turbine PSS Active and PSS Not Active set points to ensure all units complied, and confirmed gas turbines complied when in a 1 x 1 configuration; and 4) added visual and audible alarms to indicate if a PSS is not active when it should engaged. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018019535	PRC-019-2	R1	Buffalo Gap Wind Farm, LLC (AES Buffalo Gap)	NCR04025	07/01/2016	02/28/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On April 10, 2018, Buffalo Gap Wind Farm, LLC (AES Buffalo Gap) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with PRC-019-2 R1. In particular, AES Buffalo Gap did not verify the coordination of its voltage regulating system controls with the equipment capabilities and settings of applicable Protection System devices and functions for its wind generation Facility by July 1, 2016, as required. On January 18, 2016, AES Buffalo Gap engaged a contractor to complete an electrical study at its Facility intended to satisfy the requirements of PRC-019-2. This study was completed, and the draft results were provided to AES Buffalo Gap on October 5, 2016. However, this study did not fully satisfy the requirements of PRC-019-2. On November 30, 2016, AES Buffalo Gap engaged a second contractor to complete the required study. On March 16, 2017, the second study was completed, however, it was determined that the Facility remained noncompliant with PRC-019-2 at the turbine level, and that additional adjustments to turbine protection settings were necessary for compliance. AES Buffalo Gap adjusted its protection settings and a third study was completed on February 28, 2018, that provided AES Buffalo Gap with the required verification that its voltage regulating system controls were coordinated with its equipment capabilities and settings of applicable Protection System devices and functions, ending the noncompliance with PRC-019-2. The root cause of this noncompliance was that AES Buffalo Gap failed to direct the activities of its contractors in the performance of the required verifications, and failed to identify the necessary requirements for compliance with PRC-019-2 prior to the effective date of the standard. This noncompliance started on July 1, 2016, when PRC-019-2 became mandatory and enforceable, and ended on February 28, 2018, when AES Buffalo Gap obtained verification that its voltage regulating system controls were coordinated with its equipment capabilities and settings of applicable Protection System devices and functions.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. This Facility did not experience any unit trips during the period of noncompliance. This Facility is relatively small, with a nameplate rating of 120.6 MW. The period of noncompliance lasted 19 months and 27 days. No harm is known to have occurred. Texas RE considered the AES Buffalo Gap's and its affiliates' compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, AES Buffalo Gap: 1) completed the coordination study of its voltage regulating system controls, protection system elements, and equipment capabilities; 2) updated its voltage protection system settings in accordance with PRC-019-2; 3) developed a detailed scope to distribute to outside consultants for future studies regarding compliance with PRC-019-2; and 4) created automatic reminders that notify applicable staff members when to perform the next coordination study. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018020358	BAL-001-TRE-1	R7	Consolidated Edison Development, Inc. (CED)	NCR11605	11/02/2015	06/20/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 6, 2018, Consolidated Edison Development, Inc. (CED) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with BAL-001-TRE-1 R7. Specifically, CED failed to operate two of its photovoltaic generating units, Alamo 5 and Alamo 7, with their governors in service and responsive to frequency when the generating units were online and released for dispatch. This noncompliance occurred at two separate Facilities during overlapping periods. The noncompliance at Alamo 5 began on November 2, 2015 and ended on June 20, 2018, fully overlapping the additional noncompliance at Alamo 7. The instance of noncompliance at Alamo 7 began on September 23, 2016, and ended April 26, 2018. The noncompliance at Alamo 5 began on November 2, 2015, when the Facility was registered with NERC and entered service with Primary Frequency Response (PFR) logic that would overwrite its actual frequency reading with a static value during certain curtailments. Alamo 5 continued operation with limited PFR until May 18, 2017, when frequency response was disabled entirely. CED speculated that the PFR logic had been disabled to address the slow morning ramp at the facility. CED discovered that PFR had been disabled on June 7, 2018 when CED was preparing Alamo 5 for compliance with MOD-026-1 and MOD-027-1. CED re-enabled PFR and modified its logic to be compliant with BAL-001-TRE-1 on June 20, 2018. The noncompliance at Alamo 7 began on September 23, 2016, when the Facility entered service with its Primary Frequency Response (PFR) logic disabled entirely. In May of 2017, CED discovered that PFR had been disabled at Alamo 7 when it was constructing Upton County Solar, LLC (Upton) and the same Supervisory Control And Data Acquisition (SCADA) integrator was used for that Facility as Alamo 7. On November 3, 2017, CED enabled PFR at Alamo 7. However, this did not fully correct the noncompliance. Similar to Alamo 5, the PFR logic at Alamo 7 had been set such that it would overwrite the actual frequency reading and replace it with a static value. CED discovered that frequency measurement was unresponsive at Alamo 7 on April 26, 2018, when CED reviewed the facility's alarm logic. CED removed the noncompliant PFR logic settings and Alamo 7 became compliant with BAL-001-TRE-1 on April 26, 2018. The root cause of this noncompliance was that CED failed to establish adequate controls around changes to Facility controls and systems made by internal personnel and third-party vendors. This noncompliance started on 1 November 2, 2015, when Alamo 5 entered service without its PFR fully enabled, and ended on June 20, 2018, when Alamo 5's PFR was fully enabled.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system for the following reasons. First, solar photovoltaic facilities operate at maximum output based on available sunlight at any given time. For this reason, solar plants are typically unable to respond to underfrequency events, but capable to respond to overfrequency events. The only scenario where the facility can respond to underfrequency events is during (rare) curtailments, when the solar facility will have MW headroom. Second, the generation units at issue are relatively small, with a maximum output capability of 95 MW for Alamo 5 and 106.4 MW for Alamo 7. Furthermore, the maximum PFR contribution (if producing at capacity), is below 3.56 MW per 0.1 Hz at Alamo 7 and 3.18 MW per 0.1 Hz at Alamo 5. According to CED, Alamo 5 and Alamo 7 rarely operate steadily at capacity. Third, ERCOT Frequency Measureable Events (FMEs) during the possible non-compliance period, in which the plants participated, were all underfrequency events and both Alamo 5 and Alamo 7 received a status of "No Evaluation," indicating that PFR from these facilities was not required during the FME events. No harm is known to have occurred. Texas RE considered CED's and its affiliates' BAL-001-TRE-1 compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, CED: 1) has enabled PFR where it was disabled, and removed noncompliant PFR logic that forced static values; and 2) implemented a Change Management Process to establish controls around any changes made by internal personnel and third party vendors that impact plant control systems. All changes that impact facility control systems must be reviewed and approved by CED's Engineering and operations and maintenance staff in accordance with the Change Management Process prior to implementation of any proposed modifications. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017017607	VAR-002-4	R3	Duke Energy Renewables Services, LLC (DERS) (the "Entity")	NCR11032	09/05/2015	03/28/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On May 19, 2017, the Entity submitted a Self-Report stating, as a Generator Operator (GOP), it was in noncompliance with VAR-002-4 R3. Specifically, in several instances at the Los Vientos Windpower III, LLC (LVWPIII) Facility, the Entity did not notify its associated Transmission Operator (TOP) of a status change on the automatic voltage regulator (AVR) within 30 minutes of the change. Subsequently, during a Compliance Audit conducted per an existing multi-region registered entity agreement from August 21, 2017 through October 27, 2017, Texas RE identified additional instances of noncompliance regarding VAR-002-4 R2. The scope of the noncompliance includes the LVWPIII and Notrees Windpower, LP (NOTWIN001) Facilities in the Texas RE footprint and the Cimarron Windpower II, LLC (CIMW) and Frontier Windpower LLC (Frontier) Facilities in the Midwest Reliability Organization footprint. Regarding the LVWPIII Facility, during 13 instances occurring during September 5, 2015 through March 21, 2017, the Entity did not have evidence that it timely notified the associated TOP regarding a status change on the Facility's AVR. Regarding the CIMW Facility, during one instance occurring on November 18, 2016, the AVR was disabled in order for the Entity to perform Real Power and Reactive Power verifications. Although the Entity stated that it coordinated with the associated TOP in advance of the verifications, the Entity was unable to provide evidence of the prior coordination or of any notification to the associated TOP. Finally, regarding the Frontier Facility, during one instance occurring on March 28, 2017, the Entity did not have evidence of providing a notification to the associated TOP for the period when the AVR was disabled in order for the Entity to perform software maintenance. The root cause of this issue is that the Entity did not have a sufficient process for compliance with VAR-002-4. Specifically, the Entity determined that three factors led to the noncompliance. First, the Entity did not have a sufficient formal process to provide guidance to operating personnel regarding the requirements of VAR-002-4. Second, the Entity did not have adequate alarming at its main control center for AVR status changes and control mode changes. Third, multiple users have access to make voltage control changes, instead of restricting this access to operating personnel at the main control center who would also be responsible for notifying the TOP of a change in status. This noncompliance started on September 5, 2015, when the Entity failed to notify its TOP of a status change within 30 minutes of the change, and ended on March 28, 2017, when the Entity returned the AVR for the Frontier Facility to automatic mode.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The risk from failure to notify a TOP regarding a change in AVR status could have affected a TOP's ability to effectively monitor and ensure the real-time operating reliability of the BPS. However, the risk posed by this issue was reduced by the following factors. First, during periods when the Facilities were operated with the AVR's automatic mode disabled, the Entity possessed other methods of controlling voltage at the respective points of interconnection. During each instance of noncompliance, the Entity was able to comply with all instructions from a TOP to modify voltage settings. Second, the wind generation Facilities at issue are small, with Facility Ratings ranging from 138 MVA to 211 MVA and with average output during September 5, 2015 through March 28, 2017 ranging from approximately 64 MW to 90 MW. As a result, the wind generation Facilities in question would not likely have had a substantial impact on the system's ability to respond to voltage deviations. No harm is known to have occurred. Texas RE considered the Entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the Entity: 1) provided notifications to the associated TOP or returned the AVR to the status consistent with the prior notification to the TOP regarding the four Facilities at issue; 2) developed a database to outline the reliability tasks that are required based on real-time events and alarms; 3) revised its procedure for Real Power and Reactive Power testing to include steps to provide notifications to the TOP, retain evidence of the notifications, and perform a validation of the AVR settings after testing is completed; 4) modified control access permissions, including voltage control access, in the Entity's control systems so that only certain operating personnel have the ability to disable AVR or change voltage control modes; 5) implemented a workflow in the Entity's logging tool for reliability tasks, including instructions and contact information for required notifications, and provided training on the workflow to operating personnel; 6) implemented alarms to alert operating personnel regarding a change in AVR status and regarding alternative voltage controls; 7) revised its process documents to include instructions to verify that alarms are not inhibited; 8) established a recurring quarterly task to review the status of alarms and performed the first review using the revised processed documents; and 9) performed reviews of the effectiveness of the Entity's mitigation activities, in which additional instances of noncompliance were identified, analyzed, and mitigated. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017017608	VAR-002-4	R2	Duke Energy Renewables Services, LLC (DERS) (the "Entity")	NCR11032	09/01/2015	06/29/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On May 19, 2017, the Entity submitted a Self-Report stating, as a Generator Operator (GOP), it was in noncompliance with VAR-002-4 R2. Specifically, on several occasions, the Entity did not maintain the generator voltage schedule provided by the Transmission Operator (TOP) or otherwise meet the conditions of notification for deviations from the voltage schedule at the several Facilities. Subsequently, during a Compliance Audit conducted per an existing multi-region registered entity agreement from August 21, 2017 through October 27, 2017, Texas RE identified additional instances of noncompliance regarding VAR-002-4 R2. The scope of the noncompliance includes the Los Vientos 1B LLC (LVWIB), Los Vientos Windpower III, LLC (LVWPIII), Los Vientos Windpower V, LLC (LVWV), and Notrees Windpower, LP (NOTWIN001) Facilities in the Texas RE footprint, the Conetoe II Solar, LLC (Conetoe) Facility in the SERC Reliability Corporation footprint, the Frontier Windpower LLC (Frontier) Facility in the Midwest Reliability Organization footprint, and the Three Buttes Windpower LLC (TBWIN) and Top of the World Wind Energy, LLC (TOPW) Facilities in the Western Electricity Coordinating Council footprint. The first instance of noncompliance was identified by the Compliance Audit as beginning on September 1, 2015, when the LVWPIII, TBWIN, and TOPW Facilities were operated outside of the applicable voltage schedules. From September 1, 2015 through June 29, 2017, the eight Facilities at issue failed to maintain their respective voltage schedules, ranging from approximately 3% to 69% of that time period. The root cause of this issue is that the Entity did not have a sufficient process for compliance with VAR-002-4. Specifically, the Entity performed a root cause analysis that identified several factors. First, the Entity did not have a sufficient process to ensure that alarm settings were updated to match changes in a Facility's assigned voltage schedule. In addition, the Entity's process did not ensure that the voltage set point and alarms were consistent across different control systems. Finally, the Entity's process did not ensure that alarms were assigned the correct priority in the Entity's control system and that alarms were not inhibited or disabled, resulting in decreased visibility regarding voltage schedule deviations. This noncompliance started on September 1, 2015, when the Entity failed to operate the LVWPIII, TOPW, and TBWIN Facilities in compliance with the applicable voltage schedules, and ended on June 29, 2017, when the Notrees Facility became compliant with the applicable voltage schedule.
Risk Assessment=	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The Entity's failure to maintain the assigned voltage schedule could result in equipment damage or insufficient reactive resources for reliable system operation. However, the risk posed by this issue was reduced by the following factors. First, during September 1, 2015 through June 29, 2017, the Entity was able to accommodate almost all instructions received from a TOP to modify voltage for the Facilities at issue, except for in two instances regarding the LVWPIII Facility and one instance regarding the LVWV Facility, during which the Entity indicated to the TOP it was not immediately able to remotely implement the requested changes. Second, the wind generation Facilities at issue are small, with Facility Ratings ranging from 90 MVA to 211 MVA and with average output during September 1, 2015 through June 29, 2017 ranging from approximately 16 MW to 87 MW. As a result, the wind generation Facilities in question would not likely have had a substantial impact on the system's ability to respond to voltage deviations. No harm is known to have occurred. Texas RE considered the Entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the Entity: 1) returned the voltage at the eight Facilities to levels consistent with the respective voltage schedules; 2) developed a documented process for implementing changes to voltage set points, for communicating the change, and for retaining evidence of the voltage set point and voltage schedule; 3) scheduled reminders for a quarterly task to review voltage set points and conducted the first quarterly review; 4) implemented monitoring and alarming in the Entity's Energy Management System for voltage deviations; 5) revised documented work instructions to include details regarding the process to review and update voltage set points when revised voltage schedules are received; and 6) performed reviews of the effectiveness of the Entity's mitigation activities, in which additional voltage deviations were identified, analyzed, and mitigated. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018597	VAR-002-4	R1	Duke Energy Renewables Services, LLC (DERS) (the "Entity")	NCR11032	09/05/2015	03/28/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted per an existing multi-region registered entity agreement from August 21, 2017 through October 27, 2017, Texas RE determined that DERS, as a Generator Operator (GOP), was in noncompliance regarding VAR-002-4 R1. Specifically, in several instances, the Entity did not operate each generator with the automatic voltage regulator (AVR) in the automatic voltage control mode and did not provide the required notification to the associated Transmission Operator (TOP). The scope of the noncompliance includes the Los Vientos Windpower III, LLC (LVWPIII) Facility in the Texas RE footprint and the Cimarron Windpower II, LLC (CIMW) and Frontier Windpower LLC (Frontier) Facilities in the Midwest Reliability Organization footprint. Regarding the LVWPIII Facility, during 10 instances occurring during September 5, 2015 through March 9, 2017, the Entity did not have evidence that it timely notified the associated TOP regarding a status change on the Facility's AVR. Regarding the CIMW Facility, during one instance occurring on November 18, 2016, the AVR was disabled in order for the Entity to perform Real Power and Reactive Power verifications. Although the Entity stated that it coordinated with the associated TOP in advance of the verifications, the Entity was unable to provide evidence of the prior coordination or of any notification to the associated TOP. Finally, regarding the Frontier Facility, during one instance occurring on March 28, 2017, the Entity did not have evidence of providing a notification to the associated TOP for the period when the AVR was disabled in order for the Entity to perform software maintenance. The root cause of this issue is that the Entity did not have a sufficient process for compliance with VAR-002-4. Specifically, the Entity determined that three factors led to the noncompliance. First, the Entity did not have a sufficient formal process to provide guidance to operating personnel regarding the requirements of VAR-002-4. Second, the Entity did not have adequate alarming at its main control center for AVR status changes and control mode changes. Third, multiple users have access to make voltage control changes, instead of restricting this access to operating personnel at the main control center who would also be responsible for notifying the TOP of a change in status. This noncompliance started on September 5, 2015, when the Entity failed to notify its TOP of a status change within 30 minutes of the change, and ended on March 28, 2017, when the Entity returned the AVR for the Frontier Facility to automatic mode.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Operating a Facility without the AVR in service and controlling voltage and without notifying the TOP could impact a TOP's ability to effectively monitor and ensure the real-time operating reliability of the BPS. However, the risk posed by this issue was reduced by the following factors. First, during periods when the Facilities were operated with the AVR's automatic mode disabled, the Entity possessed other methods of controlling voltage at the respective points of interconnection. During each instance of noncompliance, the Entity was able to comply with all instructions from a TOP to modify voltage settings. Second, the wind generation Facilities at issue are small, with Facility Ratings ranging from 138 MVA to 211 MVA and with average output during September 5, 2015 through March 28, 2017 ranging from approximately 64 MW to 90 MW. As a result, the wind generation Facilities in question would not likely have had a substantial impact on the system's ability to respond to voltage deviations. No harm is known to have occurred. Texas RE considered the Entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the Entity: 1) provided notifications to the associated TOP or returned the AVR to the status consistent with the prior notification to the TOP regarding the four Facilities at issue; 2) developed a database to outline the reliability tasks that are required based on real-time events and alarms; 3) revised its procedure for Real Power and Reactive Power testing to include steps to provide notifications to the TOP, retain evidence of the notifications, and perform a validation of the AVR settings after testing is completed; 4) modified control access permissions, including voltage control access, in the Entity's control systems so that only certain operating personnel have the ability to disable AVR or change voltage control modes; 5) implemented a workflow in the Entity's logging tool for reliability tasks, including instructions and contact information for required notifications, and provided training on the workflow to operating personnel; 6) implemented alarms to alert operating personnel regarding a change in AVR status and regarding alternative voltage controls; 7) revised its process documents to include instructions to verify that alarms are not inhibited; 8) established a recurring quarterly task to review the status of alarms and performed the first review using the revised processed documents; and 9) performed reviews of the effectiveness of the Entity's mitigation activities, in which additional instances of noncompliance were identified, analyzed, and mitigated. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018020249	VAR-002-4	R1	EC&R QSE, LLC (ECR QSE)	NCR11383	08/29/2017	08/29/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from May 29, 2018 through June 8, 2018, Texas RE determined that EC&R QSE, LLC (ECR QSE), as a Generator Operator (GOP), was in noncompliance with VAR-002-4 R1. Specifically, ECR QSE failed to operate its generator connected to the interconnected transmission system in the automatic voltage control mode. The audit team reviewed historian data for ECR QSE's generating units and determined that on August 29, 2017, Panther Creek I and Panther Creek II wind farms were operated with the Automatic Voltage Regulator (AVR) out of service for a period of 80 minutes. VAR-002-4 R1 requires GOPs to operate each generator connected to the interconnected transmission system in the automatic voltage control mode unless otherwise exempted. ECR QSE's units were not exempted from operating in voltage control mode, nor had it notified its Transmission Operator (TOP) that the generator was being operated with the AVR out of service. The root cause of the noncompliance was inadequate processes and training to ensure compliance with all applicable requirements in VAR-002-4 R1. Specifically, ECR QSE did not adequately monitor the status of its AVR. This noncompliance started on August 29, 2017, at 12:37, when ECR QSE began operating Panther I and Panther II units with the AVR out of Service, and ended on August 29, 2017, at 13:56, when ECR QSE returned the AVR back to service at Panther I and Panther II units.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The instance of noncompliance occurred for only 80 minutes, and historian data shows ECR QSE maintained its voltage profile at Panther I and Panther II during this period. No known harm is known to have occurred. Texas RE considered ECR QSE's and its affiliates' VAR-002-4 compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, ECR QSE: 1) returned the AVR back to service at Panther I and Panther II units; and 2) conducted Control Room Operator training to set expectations on handling voltage and reactive control. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018668	BAL-001-TRE-1	R10	GEUS (GEUS1)	NCR04075	10/06/2016	Present	Self-Report	10/01/2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On November 16, 2017, GEUS1 submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with BAL-001-TRE-1 R10. Specifically, GEUS1 did not meet the minimum 12-month rolling average sustained Primary Frequency Response (PFR) performance requirement of 0.75 on Steam Unit 3, based on participation in the previous eight Frequency Measurable Events (FMEs). On September 1, 2017, during a quarterly review of FMEs, GEUS1 discovered that it did not maintain at least 0.75 PFR performance on Steam Unit 3. GEUS1 was taken Off-line to avoid further decline of the unit's sustained frequency response 12-month rolling average. GEUS1 investigated the issue and concluded that this failure occurred due to settings within the boiler/turbine controls, and due to issues with a communications cable. Steam Unit 3 remains Off-line due to technical issues unrelated to this noncompliance. During the 981 day period from 10/6/2016 throuh 6/14/2019, Steam Unit 3 has run approximately 97 days. GEUS1 is continuing to make repairs and conduct testing on Steam Unit 3. Once the unit is repaired GEUS1 will complete further testing to determine if its repairs have sufficiently addressed the unit's sustained frequency response performance. The root cause of this noncompliance was various technical issues at Steam Unit 3. In particular, Steam Unit 3's frequency error limiter and gain settings within the boiler/turbine controls were set with a deadband's bandwidth of +/- 0.2 Hz. Additionally, a fiber optics cable responsible for maintaining frequency input communication was faulty. This noncompliance started on October 6, 2016, when Steam Unit 3's sustained Primary Frequency Response (PFR) performance fell below the minimum 12-month rolling average requirement of 0.75, and continues through the present.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, Steam Unit 3 is relatively small with a maximum output of 41 MW. Second, this unit accounted for approximately 0.02% of ERCOT Load at the time the FMEs occurred. Finally, the ERCOT Interconnection possesses several other methods to respond to frequency measurable events, including primary frequency response from other units with mechanical governors and Load Resource Under Frequency Relays. No harm is known to have occurred. Texas RE considered GEUS1's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, GEUS: 1) adjusted the boiler/turbine control settings for a deadband's bandwidth to +/- 0.034 Hz, and revised the control from Boiler Follow Mode to Coordinated Mode; 2) replaced the fiber optics cable responsible for maintaining frequency input communication to ensure that a proper connection is maintained; and 3) adjusted its procedure for review of FME's so that they are reviewed as they are posted. To mitigate this noncompliance, GEUS will complete the following mitigation activities by October 1, 2019: 1) place Steam Unit 3 On-line August 1, 2019 through September 2019; 2) conduct a governor test; and 3) analyze FMEs as posted by ERCOT.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017017610	PRC-005-2(i)	R3	Los Vientos Windpower IA, LLC (LVWIA) (the "Entity")	NCR11267	10/01/2015	08/18/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On May 19, 2017, prior to a Compliance Audit, the Entity submitted a Self-Report under an existing multi-region registered entity agreement stating that, as a Generator Owner (GO), it was in noncompliance with PRC-005-2(i) R3. Specifically, the Entity failed to maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance prescribed intervals. The Entity had two instances of noncompliance with PRC-005-2(i) R3. In the first instance, the Entity failed to timely complete the six-calendar month maintenance for one Valve-Regulated Lead-Acid (VRLA) battery as specified in Table 1-4(b). The maintenance was due to be performed on or before November 30, 2015; however, the maintenance was not completed until March 24, 2016, due to work was being completed at the Facility for feeder cable repairs. For the second instance, PRC-005-2(i), Table 1-2 requires entities to verify the functionality of unmonitored communications systems every four-calendar months, and per the Implementation Plan entities must perform the initial required four-calendar month verifications by October 1, 2015. The Entity mistakenly believed that the relay failure alarm received in the control center was sufficient for extended maintenance intervals for monitored communications systems. Therefore, the quarterly maintenance for two unmonitored communications systems was not implemented until August 18, 2017. The root cause of the first instance was a failure to timely complete the required VRLA battery maintenance due to on-site repairs. The root cause for the second instance was a misunderstanding of the Requirement and an insufficient process for maintenance activities for unmonitored communications systems. Although the Entity had a general relay failure alarm system in place it was not sufficient for monitoring the channel function to allow extended maintenance intervals for monitored communications systems. Absent sufficient continuous monitoring, the Entity could not utilize extended maintenance intervals for communications systems and quarterly verifications were required pursuant to Table 1-2. This noncompliance started on October 1, 2015, the enforcement date for verification of unmonitored communication systems, and ended on August 18, 2017, when the Entity completed the required maintenance activities for the Protection System devices at issue.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, the devices at issue represent approximately three percent (3/70) of the total Protection System devices in the Entity's Protection System Maintenance Program (PSMP). Second, the Entity did not identify any issues with the battery and communications systems when it performed the required maintenance activities for the devices at issue. Third, for the two unmonitored communication systems at issue the Entity performed the six-calendar year verification on October 5, 2016. Finally, the single generation Facility is small, with a nameplate rating of 200 MW. No harm is known to have occurred. Texas RE determined that the Entity's compliance history should not serve as a basis for applying a penalty. Texas RE concluded that the prior instance of noncompliance (TRE2014014271) should not serve as an aggravating factor because the root cause is distinguishable from the current noncompliance. In TRE2014014271, the Entity was in noncompliance with PRC-005-1b R1 because it misunderstood certain interval durations, resulting in the maintenance interval durations not matching the documentation referenced for the basis of the intervals.
Mitigation	To mitigate this noncompliance, the Entity: 1) performed the required maintenance activities for the devices at issue; 2) utilized the asset management tool to create an asset list for assignment of work orders and maintenance records; 3) created automated e-mails in the asset management tool to send deadline reminders to management and compliance personnel; 4) revised the PSMP to include a quarterly functional check of communications systems if alarming is not provided; 5) updated its NERC Implementation Checklist to include specific requirements for alarm path implementation and testing; and 6) implemented and tested communications systems failure alarms to be received in the control center. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017017611	PRC-005-2(i)	R3	Los Vientos Windpower IB, LLC (LVWIB) (the "Entity")	NCR11266	10/01/2015	08/18/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On May 19, 2017, prior to a Compliance Audit, the Entity submitted a Self-Report under an existing multi-region registered entity agreement stating that, as a Generator Owner (GO), it was in noncompliance with PRC-005-2(i) R3. Specifically, the Entity failed to maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance prescribed intervals. The Entity had two instances of noncompliance with PRC-005-2(i) R3. In the first instance, the Entity failed to timely complete the four-calendar month and six-calendar month intervals, as specified in Table 1-4(b), for one Valve-Regulated Lead-Acid (VRLA) battery. The four-calendar month maintenance was due to be performed January 31, 2016, but was not completed until February 26, 2016. The six-calendar month maintenance was due to be performed November 30, 2015, but was not completed until March 25, 2016. The delay for both maintenance activities was due to work being completed at the Facility for feeder cable repairs. For the second instance, PRC-005-2(i), Table 1-2 requires entities to verify the functionality of unmonitored communications systems every four-calendar months and per the Implementation Plan entities must perform the initial required four-calendar month verifications by October 1, 2015. The Entity mistakenly believed that the relay failure alarm received in the control center was sufficient for extended maintenance intervals for monitored communications systems. Therefore, the quarterly maintenance for two unmonitored communications systems was not implemented until August 18, 2017. The root cause of the first instance was failure to timely complete the required VRLA battery maintenance due to on-site repairs. The root cause for the second instance was a misunderstanding of the Requirement and an insufficient process for maintenance activities for unmonitored communications systems. Although the Entity had a general relay failure alarm system in place it was not sufficient for monitoring the channel function to allow extended maintenance intervals for monitored communications systems. Absent sufficient continuous monitoring, the Entity could not utilize extended maintenance intervals for communications systems and quarterly verifications were required pursuant to Table 1-2. This noncompliance started on October 1, 2015, the enforcement date for verification of unmonitored communication systems, and ended on August 18, 2017, when the Entity completed the required maintenance activities for the Protection System devices at issue.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, the devices at issue represent approximately five percent (3/64) of the total Protection System devices in the Entity's Protection System Maintenance Program (PSMP). Second, the Entity did not identify any issues with the battery and communications systems when it performed the required maintenance activities for the devices at issue. Third, for the two unmonitored communications systems at issue, the Entity performed the six-calendar year verification on December 23, 2015. Finally, the single generation Facility at issue is small, with a nameplate rating of 202 MW. No harm is known to have occurred. Texas RE determined that the Entity's compliance history should not serve as a basis for applying a penalty. Texas RE concluded that the prior instance of noncompliance (TRE2014014270) should not serve as an aggravating factor because the root cause is distinguishable from the current noncompliance. In TRE2014014270, the Entity was in noncompliance with PRC-005-1b R1 because it misunderstood certain interval durations, resulting in the maintenance interval durations not matching the documentation referenced for the basis of the intervals.
Mitigation	To mitigate this noncompliance, the Entity : 1) performed the required maintenance activities for the devices at issue; 2) reviewed battery maintenance templates and cross-matched with PRC-005-6 intervals to confirm compliance was documented. Added pass/fail criteria and all required maintenance activities in battery inspection templates; 3) developed training on new battery maintenance templates, and conducted training with impacted personnel to ensure consistent use of templates for compliance evidence; 4) utilized its asset management tool to create an asset list for assignment of work orders and maintenance records; 5) created automated e-mails in the asset management tool to send deadline reminders to management and compliance personnel; 6) revised the PSMP to include a quarterly functional check of communications systems if alarming is not provided; 7) updated its NERC Implementation Checklist to include specific requirements for alarm path implementation and testing; and 8) implemented and tested communications systems failure alarms to be received in the control center. Texas RE has verified the completion of all mitigation activities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017017612	PRC-005-2(i)	R3	Los Vientos Windpower III, LLC (LVWPIII) (the "Entity")	NCR11538	10/01/2015	08/18/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On May 19, 2017, prior to a Compliance Audit, the Entity submitted a Self-Report under an existing multi-region registered entity agreement stating that, as a Generator Owner (GO), it was in noncompliance with PRC-005-2(i) R3. Specifically, the Entity failed to maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance prescribed intervals. Table 1-2 of PRC-005-2(i) requires entities to verify the functionality of unmonitored communications systems every four-calendar months, and per the Implementation Plan, entities must perform the initial required four-calendar month verifications by October 1, 2015. The Entity failed to perform the required maintenance verification due to a mistaken belief that the relay failure alarm received in the control center was sufficient for monitoring the channel function to allow extended maintenance intervals for monitored communication systems. Therefore, the required four-calendar month maintenance for two unmonitored communications systems was not implemented and completed until August 18, 2017. The root cause of this issue was a misunderstanding of the Requirement and an insufficient process for maintenance activities for unmonitored communication systems. Although the Entity had a general relay failure alarm system in place it was not sufficient for monitoring the channel function to allow for extended maintenance intervals for monitored communications systems. Absent sufficient continuous monitoring, the Entity could not utilize extended maintenance intervals for communications systems and verifications every four-calendar months were required pursuant to Table 1-2. This noncompliance started on October 1, 2015, the enforcement date of the four-month maintenance interval specified in PRC-005-2(i), Table 1-2, and ended on August 18, 2017, when the Entity performed the required quarterly maintenance for the two unmonitored communications systems devices at issue.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, the devices at issue represent less than three percent (2/88) of the total Protection System devices in the Entity's Protection System Maintenance Program (PSMP). Second, the Entity did not identify any issues with the communications systems when it performed the maintenance activities for the devices at issue. Finally, the single generation Facility at issue is small, with a nameplate rating of only 200 MW. No harm is known to have occurred. Texas RE considered the Entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the Entity: 1) performed the required maintenance activities for the devices at issue; 2) reviewed battery maintenance templates and cross-matched with PRC-005-6 intervals to confirm compliance was documented. Added pass/fail criteria and all required maintenance activities in battery inspection templates; 3) conducted training with impacted personnel on new battery templates; 4) utilized the asset management tool to create an asset list for assignment of work orders and maintenance records; 5) created automated e-mails in the asset management tool to send deadline reminders to management and compliance personnel; 6) revised the PSMP to include a quarterly functional check of communications systems if alarming is not provided; 7) updated its NERC Implementation Checklist to include specific requirements for alarm path implementation and testing; and 8) implemented and tested communications systems failure alarms to be received at the control center. Texas RE has verified completion of all mitigation activities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017017613	PRC-005-6	R3	Los Vientos Windpower IV, LLC (LVIV) (the "Entity")	NCR11635	05/25/2016	08/18/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On May 19, 2017, prior to a Compliance Audit, the Entity submitted a Self-Report under an existing multi-region registered entity agreement stating that, as a Generator Owner (GO), it was in noncompliance with PRC-005-2(i) R3. Specifically, the Entity failed to maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance prescribed intervals. PRC-005-6, Table 1-2 requires entities to verify the functionality of unmonitored communications systems every four-calendar months, and per the Implementation Plan, entities must perform the initial required four-calendar month verifications by October 1, 2015. The Entity failed to perform the required maintenance verification due to a mistaken belief that the relay failure alarm received in the control center was sufficient for extended maintenance intervals for monitored communications systems. Therefore, the required four-calendar month maintenance for two unmonitored communications systems was not implemented until August 18, 2017. The root cause of this issue was a misunderstanding of the Requirement and an insufficient process for maintenance activities for unmonitored communications systems. Although the Entity had a general relay failure alarm system in place, it was not sufficient for monitoring the channel function to allow extended maintenance intervals for monitored communications systems. Absent sufficient continuous monitoring, the Entity could not utilize extended maintenance intervals for communications systems and verifications every four-calendar months were required pursuant to Table 1-2. This noncompliance started on May 25, 2016, the GO registration date for the Entity, and ended on August 18, 2017, when the Entity performed the required four-calendar month maintenance for the two unmonitored communication systems devices at issue.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system for the following factors. First, the devices at issue represent less than two percent (2/71) of the total Protection System devices in the Entity's Protection System Maintenance Program (PSMP). Second, the Entity did not identify any issues with the communications systems when it performed the required maintenance activities for the devices at issue. Third, for the two unmonitored communication systems at issue, the Entity performed the six-calendar year verification specified in Table 1-2 on November 4, 2015. Finally, the single generation Facility at issue is small, with a nameplate rating of only 200 MW. No harm is known to have occurred. Texas RE considered the Entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the Entity: 1) performed the required maintenance activity for the devices at issue; 2) revised the PSMP to include a quarterly functional check of communications systems if alarming is not provided; 3) updated its NERC Implementation Checklist to include specific requirements for alarm path implementation and testing; and 4) implemented and tested alarms for relay communications systems failures. Texas RE has verified the completion of all mitigation activities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017017614	PRC-005-2(i)	R3	Los Vientos Windpower V, LLC (LVWV) (the "Entity")	NCR11603	12/01/2015	08/18/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On May 19, 2017, prior to a Compliance Audit, the Entity submitted a Self-Report under an existing multi-region registered entity agreement stating that, as a Generator Owner (GO), it was in noncompliance with PRC-005-2(i) R3. Specifically, the Entity failed to maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance prescribed intervals. PRC-005-2(i), Table 1-2 requires entities to verify the functionality of unmonitored communications systems every four-calendar months and per the Implementation Plan, entities must perform the initial required four-calendar month verifications by October 1, 2015. The Entity failed to perform the required maintenance verification due to a mistaken belief that the relay failure alarm received in the control center was sufficient for extended maintenance intervals for monitored communications systems. Therefore, the required four-calendar month maintenance for two unmonitored communications systems was not implemented until August 18, 2017. The root cause of this issue was a misunderstanding of the Requirement and an insufficient process for maintenance activities for unmonitored communications systems. Although the Entity had a general relay failure alarm system in place it was not sufficient for monitoring the channel function to allow extended maintenance intervals for monitored communications systems. Absent sufficient continuous monitoring, the Entity could not utilize extended maintenance intervals for communications systems and verifications every four-calendar months were required pursuant to Table 1-2. This noncompliance started on December 1, 2015, the GO registration date for the Entity, and ended on August 18, 2017, when the Entity performed the required four-calendar month maintenance for the two unmonitored communication system devices at issue.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, the devices at issue represent approximately 3% (2/65) of the total Protection System devices in the Entity's Protection System Maintenance Program (PSMP). Second, the Entity did not identify any issues with the communications systems when it performed the required maintenance activities for the devices at issue. Third, for the two unmonitored communications systems at issue, the Entity performed the six-calendar year verification specified in Table 1-2 on November 4, 2015. Finally, the single generation Facility at issue is small, with a nameplate rating of only 110 MW. No harm is known to have occurred. Texas RE considered the Entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the Entity: 1) performed the required maintenance activity for the devices at issue; 2) revised the PSMP to include a quarterly functional check of communications systems if alarming is not provided; 3) updated its NERC Implementation Checklist to include specific requirements for alarm path implementation and testing; and 4) implemented and tested alarms for relay communications systems failures. Texas RE has verified completion of all mitigation activities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018269	MOD-025-2	R2	Major Oak Power, LLC (MOPLLC)	NCR11493	07/01/2016	06/16/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from July 25, 2017 through July 27, 2017, Texas RE determined that Major Oak Power, LLC (MOPLLC), as a Generator Owner (GO), was in noncompliance with MOD-025-2 R2 relating to the verification of Reactive Power capability. In particular, MOPLLC did not timely perform the requisite Reactive Power capability verifications for its two generating units prior to the effective date of the Reliability Standard or provide the results of those verifications to its Transmission Planner (TP) as required. During the Compliance Audit, Texas RE determined that MOPLLC had not completed the required Reactive Power capability verification testing by the July 1, 2016, deadline. MOPLLC provided evidence that it had performed Reactive Power capability over-excited and under-excited verifications in September and November of 2014, and in September of 2016 and January 2017. Texas RE determined that the verifications were conducted pursuant to ERCOT-specific Nodal Operating Guide parameters and did not meet the requirements of MOD-025-2, Attachment 1. Specifically, various portions of the verifications performed by MOPLLC in 2014, 2016, and 2017 were performed for a period of 15 minutes, instead of one hour as required by the Standard. Further, MOPLLC's 2014 verifications did not include the maximum leading reactive values at the maximum Real Power output, or the maximum lagging reactive values at the minimum Real Power output, and MOPLLC's 2016 and 2017 verifications did not include the maximum lagging reactive values at the minimum Real Power output. MOPLLC retested its units for the required one hour and submitted the missing reactive values, along with a one-line diagram, to its TP via ERCOT's Net Dependable Capability and Reactive Capability (NDCRC) portal on June 16, 2017. The root cause of this noncompliance is that, prior to the effective date of MOD-025-2, MOPLLC failed to update its procedure for compliance with all of the applicable requirements of the Standard including the required length of time for the testing, and other specific details. This noncompliance began on July 1, 2016, when MOD-025-2 became enforceable, and ended on June 16, 2017, when MOPLLC provided the required Reactive Power verifications to its TP.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. MOPLLC performed Reactive Power capability over-excited and under-excited verification for both units, just not for the time period specified in MOD-025-2, Attachment 1. The length of this noncompliance was 350 days. No harm is known to have occurred. Texas RE considered MOPLLC's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, MOPLLC: 1) completed required Reactive Power verifications; 2) provided all required Reactive Power verifications to its TP; 3) adopted a documented process for compliance with MOD-025-2; and 4) created automatic reminders to advise staff of pending compliance deadlines. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017017606	PRC-005-1b	R2	Notrees Windpower, LP (NOTWIN001) (the "Entity")	NCR10276	08/19/2013	10/05/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On May 19, 2017, prior to a Compliance Audit, NOTWIN001 submitted a Self-Report under an existing multi-region registered entity agreement stating that one Generator Owner (GO) within the Texas RE footprint and additional GOs located in regions outside of the Texas RE footprint were in noncompliance with PRC-005-2(i) R3. Specifically, the GOs failed to maintain certain Protection System components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance prescribed intervals. Texas RE determined that the issues in the Self-Report applied to NOTWIN001 as a GO in the Texas RE region under NCR10276, to Frontier Windpower, LLC (Frontier) as a GO in the Midwest Reliability Organization (MRO) region under NCR11692, and to Ironwood Windpower, LLC (Ironwood) as a GO in the Midwest Reliability Organization (MRO) region under NCR11257. Subsequently, during a Compliance Audit conducted per an existing multi-region registered entity agreement from August 21, 2017, through September 1, 2017, Texas RE determined that NOTWIN001, as a GO, was in noncompliance with PRC-005-1b R2. Specifically, NOTWIN001 failed to maintain and test one Protection System device within the defined interval. Texas RE further determined that the duration of this issue was from August 19, 2013, until April 7, 2017. Accordingly, Texas RE determined that although PRC-005-2(i) R3 was originally applicable to the issue described in the Self-Report, PRC-005-1b R2 applies to the Compliance Audit instance. For the Self-Report instances involving NOTWIN001 and Frontier, during an internal compliance review the entities discovered that Protection System components were not maintained within the maximum maintenance interval required in PRC-002-(i), Table 1-2. PRC-005-2(i), Table 1-2 requires entities to verify the functionality of unmonitored communications systems every four calendar months and per the Implementation Plan, entities must perform the initial required four-calendar-month verifications by October 1, 2015. However, NOTWIN001 and Frontier mistakenly believed that the relay failure alarm received in the control center was sufficient for monitoring the channel function to allow extended maintenance intervals for monitored communications systems. Therefore, the quarterly maintenance for one unmonitored communications system for NOTWIN001 was not completed until August 18, 2017, and the quarterly maintenance for two unmonitored communications systems was not completed by Frontier until October 5, 2017. The root cause for the NOTWIN001 and Frontier instances was a misunderstanding of the Requirement and an insufficient process for maintenance activities for unmonitored communications systems. Although the Entity had a general relay failure alarm system in place, it was not sufficient for monitoring the channel function to allow extended maintenance intervals for monitored communications systems. Absent sufficient continuous monitoring, the Entity could not utilize extended maintenance intervals for communications systems and quarterly verifications were required pursuant to Table 1-2. For the Compliance Audit instance, NOTWIN001 previously tested one Station DC Supply battery on August 18, 2010, and pursuant to its documented maintenance and testing program the deadline for the next test was August 18, 2013. However, NOTWIN001 did not complete the required test until October 22, 2015. The root cause for this instance was an insufficient process for tracking for asset management and inconsistent evidence for testing and maintenance of Protection System requirements. For the Self-Report instance involving Ironwood, during an internal compliance review it was discovered that one Valve Regulated Lead-Acid (VRLA) battery was not maintained within the maximum maintenance interval in PRC-005-2(i), Table 1-4(b). Two 18-month interval maintenance activities were timely performed for the one VRLA battery but lacked the float voltage of battery charger data and were therefore incomplete. The Entity completed the maintenance, including the float voltage of battery charger data, on September 19, 2017, ending the noncompliance. The root cause for this instance was an insufficient process for tracking for asset management and inconsistent evidence for testing and maintenance of Protection System requirements. The noncompliance started on August 19, 2013, one day following the three-year deadline for the battery test for the NOTWIN001 Compliance Audit instance, and ended on October 5, 2017, when Frontier completed the required maintenance for its two unmonitored communication systems at issue.
Risk Assessment	For the NOTWIN001 instances, the noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, the devices at issue represent approximately four percent (2/57) of the total Protection System devices in the Entity's Protection System Maintenance Program (PSMP). Second, the Entity did not identify any issues with the battery and communications systems when it performed the required maintenance activities for the devices at issue. Third, for the four unmonitored communication systems at issue, the Entity performed the six-calendar-year verification required by Table 1-2 on October 21, 2015. The six-calendar-year maintenance is more rigorous than the four-calendar-month maintenance, as it requires verification that the communications systems meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate) whereas the four-calendar-month maintenance requires that entities verify that the communications system is functional. Lastly, the single generation Facility is small, with a nameplate rating of 189 MW. No harm is known to have occurred. Texas RE determined that the Entity's compliance history should not serve as a basis for applying a penalty. Texas RE concluded that the prior instance of noncompliance (TRE2015014756) should not serve as an aggravating factor because the root cause is distinguishable from the current noncompliance. In TRE2015014756, the Entity was in noncompliance with PRC-005-1b R2 due to a change in site management in 2013, the need for process improvements for scheduling outages and determining work scope, and a misunderstanding of whether the commercial operation date or the initial test date should be used to set the due date of the maintenance interval.

	For the Frontier instance, this noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, the devices at issue represent approximately three percent (2/74) of the total Protection System devices in the Entity's PSMP. Second, the Entity did not identify any issues with the two unmonitored communications systems when it performed the required maintenance activities for the devices at issue. Third, for the two unmonitored communications systems at issue, the Entity performed the six-calendar-year verification on October 13, 2016. The six-calendar-year maintenance is more rigorous than the four-calendar-month maintenance, as it requires verification that the communications systems meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate), whereas the four-calendar-month maintenance requires that entities verify that the communications system is functional. Finally, the single generation Facility is small, with a nameplate rating of 200 MW. No harm is known to have occurred. Texas RE considered the Entity's compliance history and determined there were no relevant instances of noncompliance. For the Ironwood instance, this noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, the device at issue represents approximately two percent (1/39) of the total Protection System devices in the Entity's Protection System Maintenance Program (PSMP). Second, the Entity did not identify any issues with the battery when it performed the required maintenance activity. Finally, the single generation Facility is small, with a nameplate rating of 168 MW. No harm is known to have occurred. Texas RE considered the Entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, NOTWIN001: 1) performed the required maintenance activities for the devices at issue; 2) utilized the asset management tool to create an asset list for assignment of work orders and maintenance records; 3) created automated e-mails in the asset management tool to send deadline reminders to management and compliance personnel; 4) reviewed battery maintenance templates and cross-matched with PRC-005-6 intervals to confirm compliance was documented. Added pass/fail criteria and all required maintenance activities in battery inspection templates; 5) developed training on new battery maintenance templates, and conducted training with impacted personnel to ensure consistent use of templates for compliance evidence; 6) revised the PSMP to include a quarterly functional check of communications systems if alarming is not provided; 7) updated its NERC Implementation Checklist to include specific requirements for alarm path implementation and testing; and 8) implemented and tested alarms for relay communications systems failures. To mitigate this noncompliance, Frontier: 1) performed the required maintenance activity for the devices at issue; 2) revised the PSMP to include a quarterly functional check of communications systems if alarming is not provided; 3) updated its NERC Implementation Checklist to include specific requirements for alarm path implementation and testing; and 4) implemented and tested alarms for relay communications systems failures. To mitigate this noncompliance, Ironwood: 1) performed the required maintenance activity for the device at issue; 2) utilized the asset management tool to create asset a list for assignment of work orders and maintenance records; 3) created automated e-mails in the asset management tool to send deadline reminders to management and compliance personnel; 4) reviewed battery maintenance templates and cross-matched with PRC-005-6 intervals to confirm compliance was documented. Added pass/fail criteria and all required maintenance activities in battery inspection templates; and 5) developed training on new battery maintenance templates, and conducted training with impacted personnel to ensure consistent use of templates for compliance evidence. Texas RE has verified the completion of all mitigation activities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018018981	VAR-002-4	R3	Nueces Bay WLE LP (NBEC) (the “Entity”)	NCR04106	08/02/2017	11/02/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 11, 2018, the Entity submitted a Self-Report under an existing multi-region registered entity agreement stating that, as a Generator Operator (GOP), it was in noncompliance with VAR-002-4 R3. Specifically, the Entity failed to notify its associated Transmission Operator (TOP) of a status change on the power system stabilizer (PSS) within 30 minutes of the change. During a review of lessons learned for the Talen fleet for VAR-002-4.1 and a best practice review of automatic voltage regulator (AVR) alarms, the Entity identified 15 instances of noncompliance with VAR-002-4 R3 between August 2, 2017, and November 2, 2017. The longest period of time the Entity failed to notify its TOP of a PSS status change was 8.5 hours. The root cause of this noncompliance was a lack of internal controls to properly set the activation of the PSS. The PSS settings at the facility were appropriate for a 2 x 1 operation; however, the PSS dropout and return cycles were occurring in the 1 x 1 configuration without operation command or awareness. A contributing root cause was a lack of internal controls for notifications when there is a change in PSS status. The Entity determined that there was not a “PSS Not Active” alarm to alert the operator when a PSS status changed. This noncompliance started on August 2, 3017, 31 minutes after there was a change in the PSS status for the facility that was not reported to the TOP, and ended on November 2, 2017, when following the final instance of noncompliance the PSS was restored to active status to match the PSS status provided to its TOP.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, during the periods when the Facility was operating with the PSS Not Active for steam turbine 2, there were no known system perturbations, the Facility operated within its operating limits, and the Facility maintained the TOP’s voltage schedule. Second, the automatic voltage regulator (AVR) remained in service throughout each of the 15 instances. Third, there were no trips or facilities outages during the 15 instances. No harm is known to have occurred. The Entity’s compliance history includes an issue with VAR-002-1.1b R3.1 (TRE201100514). Texas RE determined the Entity’s compliance history should not serve as a basis for applying a penalty because the root cause of the previous instance is distinguishable from the current issue. In the previous instance related to VAR-002-1.1b R3.1, a unit was brought off-line due to exciter problems and subsequent repairs and when the unit went back on-line, the Entity did not enable the PSS to function automatically upon start-up.
Mitigation	To mitigate this noncompliance, the Entity: 1) restored the PSS to active status to match the PSS status provided to its TOP; 2) revised the PSS activation and de-activation set points; 3) reviewed 2 x 1 combined cycle operation and gas turbine PSS Active and PSS Not Active set points to ensure all units complied, and confirmed gas turbines complied when in a 1 x 1 configuration; and 4) added visual and audible alarms to indicate if a PSS is Not Active when it should be engaged. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018020250	PRC-024-2	R1	Pyron Wind Farm, LLC (PYR)	NCR00338	07/01/2016	05/07/2018	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from May 29, 2018, through June 8, 2018, Texas RE determined that Pyron Wind Farm, LLC (PYR), as a Generator Owner (GO), was in noncompliance with PRC-024-2 R1. Specifically, PYR failed to set its frequency protective relay settings such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the "no-trip zone" of PRC-024-2, Attachment 1. On June 21, 2016, PYR erroneously reported to its TP that PYR's High Frequency Ride-Through (HFRT) settings were compliant with PRC-024-2 R1. In response to Texas RE questions in preparation for the Compliance Audit, PYR reviewed its documentation identifying the specific status of each setting for its unit and determined that the HFRT setting had been improperly characterized in the documentation as "compliant" when, in fact, the unit was the subject of an Original Equipment Manufacturer (OEM) "equipment limitation" that prevented the unit from being calibrated so that it would not trip in the "no-trip zone" of PRC-024-2, Attachment 1. During the audit, PYR updated its documentation and re-characterized the HFRT setting from being "compliant," to having an "equipment limitation." This equipment limitation was documented and communicated to PYR's Transmission Planner (TP) and Planning Coordinator (PC) in accordance with PRC-024-2 on May 7, 2018. The root cause of this noncompliance was PYR's lack of sufficient internal controls to ensure compliance with PRC-024-2. Specifically, PYR failed to implement a procedure for reviewing and approving summary tables detailing the status of its frequency relays to ensure their accuracy. This noncompliance started on July 1, 2016, when PRC-024-2 became effective, and ended on May 7, 2018, when PYR documented and communicated to its TP and PC the equipment limitation for its unit. The duration of this noncompliance was one year, 10 months, and six days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. There are no known instances in which the Facility experienced a frequency trip due to the settings being within the no trip zone during the duration of the noncompliance. Further, had the unit tripped off-line due to its frequency relay settings, because the Facility is small (9.9 MWs), ERCOT would have possessed adequate reserves to respond. No known harm is known to have occurred. Texas RE considered PYR's and its affiliates' PRC-024-2 compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, PYR: 1) PYR documented and communicated the equipment limitation to its TP and PC on May 7, 2018. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017133	PRC-019-2	R1; R1.1.; R1.1.1; R1.1.2.	Alta Wind VIII, LLC (ALTA)	NCR11258	7/1/2016	4/9/2018	Self-Certification	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On February 28, 2017, ALTA submitted a Self-Certification stating, as a Generator Owner (GO), it was in noncompliance with PRC-019-2 R1. Specifically, on February 28, 2017, ALTA discovered, during its annual Self-Certification review, it did not coordinate the voltage regulating system controls with the applicable equipment capabilities and settings of the applicable Protection Systems devices and functions for 40% of its 50 wind generating cycle units by July 1, 2016, as required by the Implementation Plan for PRC-019-2. After reviewing all relevant information, WECC Enforcement determined ALTA failed to properly perform PRC-019-2 R1. The root cause of the noncompliance was attributed to ALTA's parent company misunderstanding the type of generating units that were applicable to the Standard. This noncompliance began on July 1, 2016, when the Standard became mandatory and enforceable and ended on April 9, 2018, when ALTA completed the required analysis to verify voltage regulating controls and system protection coordination for its generating units, for a total of 648 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. ALTA had weak preventative controls, however, as compensation, no setting changes were needed for the existing relay settings and excitation controls. Furthermore, ALTA contributes only 150 MW to the grid while operating and operates at approximately a 22% capacity factor, further reducing the risk. In addition, when the unit operated, no trips occurred due to inadequate coordination and when ALTA performed the verification, no settings changes were required. No harm is known to have occurred. WECC considered the ALTA's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, ALTA: 1) hired third-party consultants to perform required analysis of its generating units to verify regulating controls and system protection coordination; 2) developed and implemented a tracking tool to ensure that future 5-year coordination is conducted; and 3) hired services of consultants to provide support for compliance with NERC Standards. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017128	MOD-025-2	R1; R1.1; R1.2.	Alta Wind VIII, LLC (ALTA)	NCR11258	7/1/2016	12/19/2018	Self-Certification	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On February 28, 2017, ALTA submitted a Self-Certification stating, as a GO, it was in noncompliance with MOD-025-2 R1 and R2. Specifically, on February 28, 2017, ALTA discovered it did not provide its Transmission Planner (TP) with verification of the Real and Reactive Power capabilities for its 50 wind generating units, in accordance with Attachment 1 of the Standard, by the mandatory and enforceable date of the Standard. After reviewing all relevant information, WECC Enforcement determined ALTA failed to properly perform MOD-025-2 R1 and R2. The root cause of the noncompliance was attributed to ALTA's parent company misunderstanding the type of generating units that were applicable to the Standard. This noncompliance began on July 1, 2016, when the Standard became mandatory and enforceable and ended on December 19, 2018, when ALTA provided verification of the Real and Reactive Power capabilities of its generating units to its Transmission Planner, for a total of 902 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. ALTA had weak preventative, however, as compensation, wind generation is typically not utilized as a firm resource due to unpredictability. Therefore, Balancing Authorities, Transmission Operators and Transmission Owners plan and operate the grid with the expectation that wind generation may be unavailable at any time. In addition, the data gained by the Requirement is used for planning purposes to improve the accuracy of the system models used to develop contingencies and operating limits. Furthermore, ALTA contributes only 150 MW to the grid while operating and operates at approximately a 22% capacity factor, further reducing the risk. No harm is known to have occurred. WECC considered the ALTA's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, ALTA: 1) hired third party to perform verification testing of all its wind generating units; 2) completed and submitted the required Real and Reactive Power capabilities testing to its TP; and 3) implemented a compliance tracking tool to assist with management of future changes to NERC Reliability Standards. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017129	MOD-025-2	R2; R2.1.; R2.2.	Alta Wind VIII, LLC (ALTA)	NCR11258	7/1/2016	12/19/2018	Self-Certification	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On February 28, 2017, ALTA submitted a Self-Certification stating, as a GO, it was in noncompliance with MOD-025-2 R1 and R2. Specifically, on February 28, 2017, ALTA discovered it did not provide its Transmission Planner (TP) with verification of the Real and Reactive Power capabilities for its 50 wind generating units, in accordance with Attachment 1 of the Standard, by the mandatory and enforceable date of the Standard. After reviewing all relevant information, WECC Enforcement determined ALTA failed to properly perform MOD-025-2 R1 and R2. The root cause of the noncompliance was attributed to ALTA's parent company misunderstanding the type of generating units that were applicable to the Standard. This noncompliance began on July 1, 2016, when the Standard became mandatory and enforceable and ended on December 19, 2018, when ALTA provided verification of the Real and Reactive Power capabilities of its generating units to its Transmission Planner, for a total of 902 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. ALTA had weak preventative, however, as compensation, wind generation is typically not utilized as a firm resource due to unpredictability. Therefore, Balancing Authorities, Transmission Operators and Transmission Owners plan and operate the grid with the expectation that wind generation may be unavailable at any time. In addition, the data gained by the Requirement is used for planning purposes to improve the accuracy of the system models used to develop contingencies and operating limits. Furthermore, ALTA contributes only 150 MW to the grid while operating and operates at approximately a 22% capacity factor, further reducing the risk. No harm is known to have occurred. WECC considered the ALTA's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, ALTA: 1) hired third party to perform verification testing of all its wind generating units; 2) completed and submitted the required Real and Reactive Power capabilities testing to its TP; and 3) implemented a compliance tracking tool to assist with management of future changes to NERC Reliability Standards. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Completion Date
WECC2018019295	PRC-019-2	R1; R1.1.; R1.1.1; R1.1.2.	Hetch Hetchy Water and Power (HHWP)	NCR05182	7/1/2017	11/15/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On February 27, 2018, HHWP submitted a Self-Report stating, as a Generator Owner (GO) and Transmission Owner (TO), it was in noncompliance with PRC-019-2 R1. Specifically, on February 21, 2018, HHWP discovered it did not verify that it coordinated the voltage regulating system controls with the applicable equipment capabilities and settings of the applicable Protection System devices and functions for 60% of its seven generating units by, July 1, 2017, as required by the implementation plan for PRC-019-2. After reviewing all relevant information, WECC Enforcement determined that HHWP did not effectively perform PRC-019-2 R1. The root cause of the noncompliance was attributed to HHWP misunderstanding the phased implementation plan timelines for the Requirement of the Standard and lacked a formal procedure to ensure coordination of the testing was being performed during times of staff turnover. This noncompliance began on July 1, 2017, when the Standard became mandatory and enforceable, and ended on November 15, 2018, when HHWP completed the required analysis to verify voltage regulating controls and system protection coordination for the three generating units, for a total of 503 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. HHWP had weak preventative controls, however, as compensation, no setting changes were needed for the existing relay settings and excitation controls related to the Facilities in scope. Furthermore, HHWP performs data verification per the WECC Generator and Testing Validation Program, which did not identify any issues and further reduced the risk. In addition, when HHWP operated, no trips occurred due to inadequate coordination. No harm is known to have occurred. WECC considered HHWP's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, HHWP 1) performed required analysis of its three generating units to verify regulating controls and system protection coordination; 2) hired new compliance staff dedicated to NERC Reliability; 3) implemented internal Mechanical Engineering Procedure; and 4) scheduled PRC-019-2 testing in an Asset Management database (Maximo) to automate the triggering of a work order in advance of the required testing due date. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Completion Date
WECC2018019196	MOD-025-2	R1; R1.1.; R1.2.	Hetch Hetchy Water and Power	NCR05182	7/1/2016	11/15/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On February 16, 2018, HHWP submitted a Self-Report stating, as a GO, it was in noncompliance with MOD-025-2 R1 and R2. On December 28, 2017, HHWP discovered that on two occasions, it did not verify the Real and Reactive Power capabilities for five of its seven generating units, in accordance with MOD-025-2 Attachment 1, by the mandatory and enforceable date of the Standard. Second, HHWP hired a third-party contractor to perform testing for the remaining two of five generating units in accordance with MOD-025-2 Attachment 1, believing it was compliant with the second mandatory and enforceable date of the Standard, July 1, 2017. However, during HHWP's annual Self Certification review, it identified gaps in the verification data between the three of the five generating units tested according to WECC's Generator and Testing Validation Program and the two of the five generating units tested in accordance with MOD-025-2 Attachment 1. As a result, HHWP's Real and Reactive Power capabilities were not verified for 60% of its Facilities according to the implementation timeline for the Standard. After reviewing all relevant information, WECC Enforcement determined HHWP failed to properly perform MOD-025-2 R1 and R2. The root cause of this noncompliance was attributed to HHWP misunderstanding that WECC's Generator and Testing Validation Program testing results would be sufficient to satisfy the requirements for verification of Real and Reactive power capabilities for MOD-025-2 R1 and R2. This noncompliance began on July 1, 2016, when the Standard became mandatory and enforceable and ended on November 15, 2018, when HHWP provided verification of the Real and Reactive Power capabilities of five of its seven generating units to its Transmission Planner (TP), for a total of 868 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. HHWP had weak preventative controls, however, as compensation, HHWP had completed testing for three of its five generating units according to WECC's Generator and Testing Validation Program. Therefore, the TP had some of the Real and Reactive Power capabilities data of the units as the model data was being verified, thus reducing the risk. No harm is known to have occurred. WECC considered HHWP's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, HHWP 1) hired a third-party contractor to perform verification of the three generating units; 2) completed and submitted required Real and Reactive Power capabilities to its TP; 3) implemented internal Mechanical Engineering Procedure; and 4) scheduled MOD-025-2 testing in an Asset Management database (Maximo) to automate the triggering of a work order in advance of the required testing due date to provide sufficient time for all required coordination. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Completion Date
WECC2018019197	MOD-025-2	R2; R2.2.	Hetch Hetchy Water and Power	NCR05182	7/1/2016	11/15/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On February 16, 2018, HHWP submitted a Self-Report stating, as a GO, it was in noncompliance with MOD-025-2 R1 and R2. On December 28, 2017, HHWP discovered that on two occasions, it did not verify the Real and Reactive Power capabilities for five of its seven generating units, in accordance with MOD-025-2 Attachment 1, by the mandatory and enforceable date of the Standard. Second, HHWP hired a third-party contractor to perform testing for the remaining two of five generating units in accordance with MOD-025-2 Attachment 1, believing it was compliant with the second mandatory and enforceable date of the Standard, July 1, 2017. However, during HHWP's annual Self Certification review, it identified gaps in the verification data between the three of the five generating units tested according to WECC's Generator and Testing Validation Program and the two of the five generating units tested in accordance with MOD-025-2 Attachment 1. As a result, HHWP's Real and Reactive Power capabilities were not verified for 60% of its Facilities according to the implementation timeline for the Standard. After reviewing all relevant information, WECC Enforcement determined HHWP failed to properly perform MOD-025-2 R1 and R2. The root cause of this noncompliance was attributed to HHWP misunderstanding that WECC's Generator and Testing Validation Program testing results would be sufficient to satisfy the requirements for verification of Real and Reactive power capabilities for MOD-025-2 R1 and R2. This noncompliance began on July 1, 2016, when the Standard became mandatory and enforceable and ended on November 15, 2018, when HHWP provided verification of the Real and Reactive Power capabilities of five of its seven generating units to its Transmission Planner (TP), for a total of 868 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. HHWP had weak preventative controls, however, as compensation, HHWP had completed testing for three of its five generating units according to WECC's Generator and Testing Validation Program. Therefore, the TP had some of the Real and Reactive Power capabilities data of the units as the model data was being verified, thus reducing the risk. No harm number is known to have occurred. WECC considered HHWP's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, HHWP 1) hired a third-party contractor to perform verification of the three generating units; 2) completed and submitted required Real and Reactive Power capabilities to its TP; 3) implemented internal Mechanical Engineering Procedure; and 4) scheduled MOD-025-2 testing in an Asset Management database (Maximo) to automate the triggering of a work order in advance of the required testing due date to provide sufficient time for all required coordination. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019056	PRC-005-1.1b	R2; R2.1.	Sycamore Cogeneration Company (SYCC)	NCR05417	11/22/2014	12/6/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On January 26, 2018, the entity submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with PRC-005-1.1b R2. According to the entity's internal Protection System Maintenance Program (PSMP) functional testing of its phase comparison protection differential relays must be completed every four years. A third-party consultant was scheduled to test one of the entity's phase comparison protection differential relays on November 21, 2014, that had been previously tested on November 22, 2010. During this test, the serial communication port on the device failed, preventing the required testing and the third-party consultant did not inform the entity's compliance group that the issue or that the device had not been tested. On June 11, 2017, the entity conducted a compliance review of its internal maintenance tracking spreadsheet for PRC-005 and was unable to locate the phase comparison protection differential relay test reports from November 21, 2014. The entity then contacted the third-party consultant who informed the entity that he was unable to test the device due to the serial communication port failure. After reviewing all relevant information, WECC Enforcement determined the entity failed to effectively implement PRC-005-1.1b R2. The root cause was attributed to the entity's PSMP lacking documented roles and responsibilities for its compliance group planners and it did not include guidance for updating its internal maintenance tracking spreadsheet for PRC-005, resulting in a mistaken update for testing on November 21, 2014. This noncompliance began on November 23, 2014, when the entity did not test its phase comparison protection differential relay within the four-year interval and ended on December 6, 2017, when the entity tested the device, for a total of 1,111 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The entity did not implement effective preventative or detective controls to prevent the issue from occurring or detect the issue in a timely manner. However, as a compensation, the entity's generation plant affected by the issue is located at the end of the transmission line with low output of 360 MVA. Furthermore, the relays in issue were redundant in protecting the entity's equipment. The entity's prior compliance history with PRC-005-1 R2 includes NERC Violation ID: WECC2012009823. WECC determined the entity's compliance history is not relevant to the current issue and should not serve as a basis for pursuing an enforcement action and/or applying a penalty. WECC201209823 was a result of a misunderstanding of the testing requirements for a type of relay to be tested, which is distinct and different from the current issue.
Mitigation	To mitigate this noncompliance, SYCC: 1) replaced the phase comparison protection differential relay in issue with a new phase comparison protection differential relay; 2) updated its PSMP to include roles and responsibilities of personnel responsible for PRC-005 compliance, including a step to review the test report prior to updating the maintenance tracking spreadsheet with the date of last test; 3) scheduled a recurring monthly review of the maintenance tracking spreadsheet and associated evidence; 4) updated processes to require a test report to be in hand prior to updating the test date in the maintenance tracking spreadsheet; and 5) instituted a monthly accountability review to ensure that internal processes are being followed. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020873	MOD-025-2	R1; R1.2.	Sycamore Cogeneration Company (SYCC)	NCR05417	7/1/2016	10/1/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On December 20, 2018, the entity submitted a Self-Report stating that, as a GO, it was in noncompliance with MOD-025-2 R1 and R2. Specifically, on October 1, 2018, the entity discovered it did not submit a completed Attachment 2 to its Transmission Planner (TP) within 90 calendar days of verification of the Real and Reactive Power capabilities of four generating units, as required by the Standard. Although the entity performed the verification for 100% of its generating units by June 2016, the responsible personnel at the time was not sure of the correct contact at the TP to send Attachment 2. Therefore, the entity did not submit the Attachment 2 data to its TP until new responsible personnel were assigned the task and sent the data on October 1, 2018. After reviewing all relevant information, WECC Enforcement determined that the entity failed to effectively implement MOD-025-2 R1 and R2. The root cause of these issues was attributed to the entity's management's failure to oversee and ensure that the previous personnel responsible for providing Attachment 2 to its TP completed the task within 90 days. Additionally, the entity did not adequately track or update the appropriate contacts of the TP. These issues began on July 1, 2016, when the Standard became mandatory and enforceable and ended on October 1, 2018, when the entity submitted the completed Attachment 2 forms for all four generating units to its TP, for a total of 823 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The entity had weak detective and preventative controls however, it had implemented good compensating controls. Specifically, because the verification was performed in a timely manner, and the verification results were consistent with the entity's plant design data that had been previously submitted to its TP for an Interconnection study. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, SYCC: 1) submitted the completed Attachment 2 forms with verification of Real and Reactive Power capabilities of its generating units to its TP; 2) updated its MOD-025-2 procedure to include due dates and revalidation due dates; 3) validated that due dates for future MOD-025-2 requirements are identified in e-suites software program for tracking; 4) retained services of a third-party consultant to transfer its compliance responsibilities and program; and 5) will be transferring its compliance responsibilities and program to NAES. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020874	MOD-025-2	R2; R2.2.	Sycamore Cogeneration Company (SYCC)	NCR05417	7/1/2016	10/1/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On December 20, 2018, the entity submitted a Self-Report stating that, as a GO, it was in noncompliance with MOD-025-2 R1 and R2. Specifically, on October 1, 2018, the entity discovered it did not submit a completed Attachment 2 to its Transmission Planner (TP) within 90 calendar days of verification of the Real and Reactive Power capabilities of four generating units, as required by the Standard. Although the entity performed the verification for 100% of its generating units by June 2016, the responsible personnel at the time was not sure of the correct contact at the TP to send Attachment 2. Therefore, the entity did not submit the Attachment 2 data to its TP until new responsible personnel were assigned the task and sent the data on October 1, 2018. After reviewing all relevant information, WECC Enforcement determined that the entity failed to effectively implement MOD-025-2 R1 and R2. The root cause of these issues was attributed to the entity's management's failure to oversee and ensure that the previous personnel responsible for providing Attachment 2 to its TP completed the task within 90 days. Additionally, the entity did not adequately track or update the appropriate contacts of the TP. These issues began on July 1, 2016, when the Standard became mandatory and enforceable and ended on October 1, 2018, when the entity submitted the completed Attachment 2 forms for all four generating units to its TP, for a total of 823 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The entity had weak detective and preventative controls however, it had implemented good compensating controls. Specifically, because the verification was performed in a timely manner, and the verification results were consistent with the entity's plant design data that had been previously submitted to its TP for an Interconnection study. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, SYCC: 1) submitted the completed Attachment 2 forms with verification of Real and Reactive Power capabilities of its generating units to its TP; 2) updated its MOD-025-2 procedure to include due dates and revalidation due dates; 3) validated that due dates for future MOD-025-2 requirements are identified in e-suites software program for tracking; 4) retained services of a third-party consultant to transfer its compliance responsibilities and program; and 5) will be transferring its compliance responsibilities and program to NAES. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2016016574	EOP-008-1	R1	Arlington Valley, LLC - AVBA (AVBA)	NCR03049	7/1/2013	11/23/2013	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible or confirmed violation.)	During a Compliance Audit conducted from September 26, 2016 through October 5, 2016, WECC determined that AVBA, as a Balancing Authority (BA), had a violation with EOP-008-1 R1. Specifically, prior to the registration of GRID to perform the BA functions for AVBA, GRID was already contractually performing the BA functions and the Operating Plan was designed, documented and implemented by GRID on behalf of its clients. WECC found several issues with the Operating Plan AVBA utilized; a. it defined the backup functionality as being provided by remotely accessing the BA functionality from specified hotel lobbies and using laptops instead of transferring operations to a specific backup facility. AVBA incorporated an incorrect definition of facility, citing the use of laptops in a hotel lobby as implementing backup functionality in addition to an “alternate” Control Center, which did not meet the criteria of backup functionality provided by FERC’s directives in Order 6931 (R1.1); b. it listed laptop batteries as the backup power supply to the hotel building power for use from the hotel lobbies (R1.2.4); c. it did not include physical or cyber security in the hotel lobbies (R1.2.5); d. it did not include a transition period between the loss of primary control center functionality and the time to transition to the alternate control center in Austin, Texas which was used for low probability high impact events, such as hurricanes requiring evacuation of Houston, Texas. Specifically, the primary Control Center and the alternate Control Center were two and a half hours away from each other by car resulting in a period over the two-hour limit (R1.5). e. for these reasons, AVBA did not include actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality because AVBA assumed that its operators would be able to gain full operational functionality in under two hours from the hotel lobbies whenever required (R1.6.2). After reviewing all relevant information, WECC determined that AVBA failed to have an Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost that meets the requirements of EOP-008-1 R1, specifically R1.1, R1.2.4, R1.2.5, R1.5, and R1.6.2. There was a corresponding EOP-008-1 R1 violation for GRID, NERC Violation ID, WECC2016016377. The root cause of the violation was the incorrect assumptions regarding the criteria for its Operating Plan and not considering the specific sub-requirements of EOP-008-1 R1 nor FERC’s directives when it designed and created its Operating Plan. .
Risk Assessment	WECC determined that this violation posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, AVBA failed to have an Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost that meets the requirements of EOP-008-1 R1, specifically R1.1, R1.2.4, R1.2.5, R1.5, and R1.6.2. Such failure could result in AVBA not having the system functionality, power sources, nor physical and cyber security controls for backup functionality in place within the required transition period, which could result in a delay or failure in performing its BA obligations and a negative impact the BPS. In addition, personnel tasked with transferring functions to the backup or alternate control center may not understand the time requirement, prolonging the risk of a loss of generation or load. AVBA was responsible for 583 MW that was applicable to this violation. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as minor. AVBA did not have effective internal controls to detect, prevent, or compensate for this violation. However, the Operating Plan was used successfully for backup control center functionality on December 14, 2012, due to a bomb threat. In addition, the Operating Plan was used successfully during hurricane evacuation conditions and for routine training and testing of remote functionality verifying all functions could be performed using remote access functionality from 2012 to 2013. Based on this, WECC determined that there was a moderate likelihood of causing minor harm to the BPS. No harm is known to have occurred.
Mitigation	To remediate and mitigate this violation, AVBA: a. GRID registered to perform the BA functions on behalf of AVBA b. engaged a real estate firm to assist with identification of a space that will be managed by the primary BA that is accessible in approximately 90 minutes or less; c. visited spaces that have been identified by the real estate firm as potential facilities; d. modified the Operating Plan to include a summary of the risk assessment for power supply needs during a loss of primary control center condition; e. negotiated the lease and build out requirements; f. established the new EOP-008 Operating Plan that is inclusive of the primary BA managed designated facility; g. established new Operating Plan inclusive of the primary BA managed facility; and h. built out the leased space to meet requirements for backup functionality established in the EOP-008 risk based assessment.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2016016575	EOP-008-1	1	Griffith Energy, LLC (GRBA)	NCR03050	7/1/2013	11/23/2013	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	During a Compliance Audit conducted from September 26, 2016 through October 5, 2016, WECC determined that GRBA, as a Balancing Authority (BA), had a violation with EOP-008-1 R1. Specifically, prior to the registration of GRID to perform the BA functions for GRBA, GRID was already contractually performing the BA functions and the Operating Plan was designed, documented and implemented by GRID on behalf of its clients. WECC found several issues with the Operating Plan GRBA utilized; a. it defined the backup functionality as being provided by remotely accessing the BA functionality from specified hotel lobbies and using laptops instead of transferring operations to a specific backup facility. GRBA incorporated an incorrect definition of facility, citing the use of laptops in a hotel lobby as implementing backup functionality in addition to an "alternate" Control Center, which did not meet the criteria of backup functionality provided by FERC's directives in Order 693 (R1.1); b. it listed laptop batteries as the backup power supply to the hotel building power for use from the hotel lobbies (R1.2.4); c. it did not include physical or cyber security in the hotel lobbies (R1.2.5); d. it did not include a transition period between the loss of primary control center functionality and the time to transition to the alternate control center in Austin, Texas which was used for low probability high impact events, such as hurricanes requiring evacuation of Houston, Texas. Specifically, the primary Control Center and the alternate Control Center were two and a half hours away from each other by car resulting in a period over the two-hour limit (R1.5). e. for these reasons, GRBA did not include actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality because GRBA assumed that its operators would be able to gain full operational functionality in under two hours from the hotel lobbies whenever required (R1.6.2). After reviewing all relevant information, WECC determined that GRBA failed to have an Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost that meets the requirements of EOP-008-1 R1, specifically R1.1, R1.2.4, R1.2.5, R1.5, and R1.6.2. There was a corresponding EOP-008-1 R1 violation for GRID, NERC Violation ID, WECC2016016377. The root cause of the violation was the incorrect assumptions regarding the criteria for its Operating Plan and not considering the specific sub-requirements of EOP-008-1 R1 nor FERC's directives when it designed and created its Operating Plan.
Risk Assessment	WECC determined that this violation posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, GRBA failed to have an Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost that meets the requirements of EOP-008-1 R1, specifically R1.1, R1.2.4, R1.2.5, R1.5, and R1.6.2. Such failure could result in GRBA not having the system functionality, power sources, nor physical and cyber security controls for backup functionality in place within the required transition period, which could result in a delay or failure in performing its BA obligations and a negative impact the BPS. In addition, personnel tasked with transferring functions to the backup or alternate control center may not understand the time requirement, prolonging the risk of a loss of generation or load. GRBA was responsible for 579 MW that was applicable to this issue. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as minor. GRBA did not have effective internal controls to detect, prevent, or compensate for this violation. However, the Operating Plan was used successfully for backup control center functionality on December 14, 2012, due to a bomb threat. In addition, the Operating Plan was used successfully during hurricane evacuation conditions and for routine training and testing of remote functionality verifying all functions could be performed using remote access functionality from 2012 to 2013. Based on this, WECC determined that there was a moderate likelihood of causing minor harm to the BPS. No harm is known to have occurred.
Mitigation	To mitigate this issue, GRBA: a. GRID registered to perform the BA functions on behalf of GRBA b. engaged a real estate firm to assist with identification of a space that will be managed by the primary BA that is accessible in approximately 90 minutes or less; c. visited spaces that have been identified by the real estate firm as potential facilities; d. modified the Operating Plan to include a summary of the risk assessment for power supply needs during a loss of primary control center condition; e. negotiated the lease and build out requirements; f. established the new EOP-008 Operating Plan that is inclusive of the primary BA managed designated facility; g. established new Operating Plan inclusive of the primary BA managed facility; and h. built out the leased space to meet requirements for backup functionality established in the EOP-008 risk based assessment.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2016016577	EOP-008-1	R1	New Harquahala Generating Company, LLC - HGBA (HGBA)	NCR02552	7/1/2013	11/23/2013	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	During a Compliance Audit conducted from September 26, 2016 through October 5, 2016, WECC determined that HGBA, as a Balancing Authority (BA), had a violation with EOP-008-1 R1. Specifically, prior to the registration of GRID to perform the BA functions for HGBA, GRID was already contractually performing the BA functions and the Operating Plan was designed, documented and implemented by GRID on behalf of its clients. WECC found several issues with the Operating Plan HGBA utilized; a. it defined the backup functionality as being provided by remotely accessing the BA functionality from specified hotel lobbies and using laptops instead of transferring operations to a specific backup facility. HGBA incorporated an incorrect definition of facility, citing the use of laptops in a hotel lobby as implementing backup functionality in addition to an "alternate" Control Center, which did not meet the criteria of backup functionality provided by FERC's directives in Order 693 (R1.1); b. it listed laptop batteries as the backup power supply to the hotel building power for use from the hotel lobbies (R1.2.4); c. it did not include physical or cyber security in the hotel lobbies (R1.2.5); d. it did not include a transition period between the loss of primary control center functionality and the time to transition to the alternate control center in Austin, Texas which was used for low probability high impact events, such as hurricanes requiring evacuation of Houston, Texas. Specifically, the primary Control Center and the alternate Control Center were two and a half hours away from each other by car resulting in a period over the two-hour limit (R1.5). e. for these reasons, HGBA did not include actions to manage the risk to the BES during the transition from primary to backup functionality as well as during outages of the primary or backup functionality because HGBA assumed that its operators would be able to gain full operational functionality in under two hours from the hotel lobbies whenever required (R1.6.2). After reviewing all relevant information, WECC determined that HGBA failed to have an Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost that meets the requirements of EOP-008-1 R1, specifically R1.1, R1.2.4, R1.2.5, R1.5, and R1.6.2. There was a corresponding EOP-008-1 R1 violation for GRID, NERC Violation ID, WECC2016016377. The root cause of the violation was the incorrect assumptions regarding the criteria for its Operating Plan and not considering the specific sub-requirements of EOP-008-1 R1 nor FERC's directives when it designed and created its Operating Plan.
Risk Assessment	WECC determined that this violation posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, HGBA failed to have an Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost that meets the requirements of EOP-008-1 R1, specifically R1.1, R1.2.4, R1.2.5, R1.5, and R1.6.2. Such failure could result in HGBA not having the system functionality, power sources, nor physical and cyber security controls for backup functionality in place within the required transition period, which could result in a delay or failure in performing its BA obligations and a negative impact the BPS. In addition, personnel tasked with transferring functions to the backup or alternate control center may not understand the time requirement, prolonging the risk of a loss of generation or load. HGBA was responsible for 933 MW that was applicable to this issue. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as minor. HGBA did not have effective internal controls to detect, prevent, or compensate for this violation. However, the Operating Plan was used successfully for backup control center functionality on December 14, 2012, due to a bomb threat. In addition, the Operating Plan was used successfully during hurricane evacuation conditions and for routine training and testing of remote functionality verifying all functions could be performed using remote access functionality from 2012 to 2013. Based on this, WECC determined that there was a moderate likelihood of causing minor harm to the BPS. No harm is known to have occurred.
Mitigation	To mitigate this issue, HGBA: a. Gridforce Energy Management, LLC (GRID) registered to perform the BA functions on behalf of HGBA b. engaged a real estate firm to assist with identification of a space that will be managed by the primary BA that is accessible in approximately 90 minutes or less; c. visited spaces that have been identified by the real estate firm as potential facilities; d. modified the Operating Plan to include a summary of the risk assessment for power supply needs during a loss of primary control center condition; e. negotiated the lease and build out requirements; f. established the new EOP-008 Operating Plan that is inclusive of the primary BA managed designated facility; g. established new Operating Plan inclusive of the primary BA managed facility; and h. built out the leased space to meet requirements for backup functionality established in the EOP-008 risk based assessment.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
FRCC2019021389	MOD-026-1	R6.	Seminole Electric Cooperative (SEC)	NCR00068	1/29/2017	4/18/2019	Self-Report	Completed
Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed noncompliance.)	On April 22, 2019, SEC submitted a Self-Report stating that, as a Transmission Planner, it was in noncompliance with MOD-026-1 R6. This noncompliance started on January 29, 2017, when SEC failed to determine usability of their verified excitation system and plant volt/var control function models provided by their Generator Owners (GOs). The period of noncompliance ended on April 18, 2019, when the verified excitation system and plant volt/var control function models were initialized by SEC to confirm usability of the models with subsequent notification to the GO. Specifically, SEC failed to determine usability of the verified excitation system and plant volt/var control function models for the required generators before providing a written response to the GO that the models were usable without errors. SEC performed an extent of condition and determined that 30% of SEC's verified generating units, required proper usability analyses pursuant to MOD-026-1. The proper usability analyses have since been performed along with notifications to SEC's GOs as required. The cause of this noncompliance was staff misinterpretation of applicable MOD-026-1 Requirements.							
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. SEC's failure to verify the usability of the modeled data could have allowed a flawed model to be used resulting in system simulations that would have demonstrated flawed unit responses. Furthermore, the risk is minimal because the updated models that SEC receives from their respective GOs are incorporated into the FRCC area-wide models, as scheduled by the FRCC PC and the NERC MMWG, and reviewed for any initialization errors. During the FRCC PC area builds, none of SEC updated models were rejected due to usability issues. Furthermore, subsequent review of these models by SEC staff determined that all the models were usable. No harm is known to have occurred. The Region determined that the Entity's compliance history should not serve as a basis for applying a penalty.							
Mitigation	To mitigate this noncompliance, SEC: 1) tested all generator models before being placed in the final FRCC PC area-wide model (during this process, none of SEC's submitted models were rejected due to non-usability by the FRCC or the NERC MMWG); 2) verified all the previously supplied models for usability and have found all the SEC GO models to be usable; 3) hardened the MOD-026 Department procedures to explicitly require the Transmission Planner to perform the necessary model usability checks and not rely on contractor performed verifications; 4) trained applicable personnel on revised MOD-026 Department procedure.							

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
FRCC2019021390	MOD-027-1	R5.	Seminole Electric Cooperative (SEC)	NCR00068	1/29/2017	4/18/2019	Self-Report	Completed
Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed noncompliance.)	On April 22, 2019, SEC submitted a Self-Report stating that, as a Transmission Planner, it was in noncompliance with MOD-027-1 R5. This noncompliance started on January 29, 2017, when SEC failed to determine usability of the turbine/governor and load control or active power/frequency control function models provided by their Generator Owners (GOs). The period of noncompliance, which ended on April 18, 2019, when the turbine/governor and load control or active power/frequency control function models were initialized by SEC to confirm usability of the model with subsequent notification to the GO. Specifically, SEC failed to determine usability of the turbine/governor and load control or active power/frequency control function models for the required generators before providing a written response to the GO that the models were usable without errors. SEC performed an extent of condition and determined that 30% of SEC's verified generating units required proper usability analyses pursuant to MOD-027-1. The proper usability analyses were performed along with new notifications sent out to SEC's GOs as required. The cause of this noncompliance was a staff misinterpretation of applicable MOD-027-1 Requirements.							
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. SEC's failure to verify the usability of the modeled data could have allowed a flawed model to be used resulting in system simulations that would have demonstrated flawed unit responses. Furthermore, the risk is minimal because the updated models that SEC receives from their respective GOs are incorporated into FRCC area-wide models as scheduled by the FRCC PC and the NERC MMWG and reviewed for any initialization errors. During the FRCC PC area builds, none of SEC updated models were rejected due to usability issues. Furthermore, subsequent review of these models by SEC staff determined that all the models were usable. No harm is known to have occurred. The Region determined that the Entity's compliance history should not serve as a basis for applying a penalty.							
Mitigation	To mitigate this noncompliance, SEC: 1) tested all generator models before being placed in the final FRCC PC area-wide model (during this process, none of SEC's submitted models were rejected due to non-usability by the FRCC or the NERC MMWG); 2) verified all the previously supplied models for usability and have found all the SEC GO models to be usable 3) hardened the MOD-027 Department procedure to explicitly require the Transmission Planner to perform the necessary model usability checks and not rely on the contractor performed verifications; and 4) trained applicable personnel on MOD-027 Department procedure.							

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020197	VAR-002-4.1	R4	Dempsey Ridge Wind Farm, LLC (DRWF)	NCR11179	05/14/2018	05/14/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On August 6, 2018, Dempsey Ridge Wind Farm, LLC (DRWF) submitted a Self-Report stating that as a Generator Operator, it was in noncompliance with VAR-002-4.1 R4. DRWF reported that, at 23:47 on May 13, 2018, it experienced a loss of one of two 4 Mvar Power Module Enclosures located within the Facility's dynamic var compensator. DRWF did not notify its Transmission Operator (TOP) of the reduction in reactive power capability until 1:07 on May 14, 2018, 80 minutes after the initial reduction in reactive power capability. The cause of the noncompliance was that DRWF reported that it failed to initiate its procedure utilized to maintain network voltage schedules, which includes notifying the TOP regarding changes in reactive power capability. This noncompliance started on May 14, 2018, 31 minutes after the loss in reactive power, and ended later on May 14, 2018, when DRWF notified its TOP.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Per DRWF, the noncompliance was limited to a 50 minute delayed notification for a single 4 Mvar device at a Facility with a capacity over 100 Mvar. DRWF states that the capacitor banks and wind turbine generators continued to supply reactive power during the noncompliance period. Additionally, due to DRWF's relatively small size (132 MW) and the non-dispatchable nature of wind farms, this Facility would have only a minor effect on the reliability of the system and the ability to control system voltage. Further, DRWF is not a part of a Remedial Action Scheme (RAS) and is not associated with any Interconnection Reliability Operating Limit (IROL). Finally, DRWF reports that at the time of the noncompliance, the DRWF Facility was coming offline and equipment was being reset due to inclement ambient conditions in the area (thunderstorms); this indicates that there was not a reliability need for reactive power support from DRWF at the time of the noncompliance. No harm is known to have occurred. DRWF has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, DRWF: 1) notified the TOP of the change in reactive power capability; 2) conducted re-training for all applicable control center personnel on its procedures for maintaining network voltage schedules, including the requirement to notify the TOP for changes in reactive power capability; and 3) distributed an internal awareness notification to its operations, maintenance, and compliance personnel to provide awareness of the event and the subsequent noncompliance, and to reinforce appropriate corrective actions to prevent reoccurrence.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SPP2018019387	PRC-004-5(i)	R1	Grand River Dam Authority (GRDA)	NCR01101	11/10/2017	11/15/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On March 14, 2018, Grand River Dam Authority (GRDA) submitted a Self-Report stating that as a Transmission Owner, it was in noncompliance with PRC-004-5(i) R1. GRDA did not identify a BES interrupting device operation as a misoperation until 126 calendar days after the operation of the BES interrupting device. The cause of the noncompliance that GRDA's controls were insufficient to ensure it initiated the procedure to analyze BES interrupting device operations per the timing requirements of R1. The noncompliance start date is November 10, 2017, when GRDA staff did not identify a BES interrupting device operation as a misoperation within 120 days, and the noncompliance end date is November 15, 2017, when GRDA's staff completed the formal analysis and documentation of the operation and determined it was a misoperation.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The misoperation affected only GRDA's 161kV system and the noncompliance was limited to six days. Also, GRDA treated the event as a misoperation; however, GRDA did not formally make its determination to classify this event as a misoperation per R1 by the required date, limiting the noncompliance to primarily a documentation-related issue. No harm is known to have occurred. GRDA has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, GRDA: 1) completed the formal analysis and documentation of the operation and determined it was a misoperation; and 2) incorporated an internal control worksheet which allows GRDA to have better visibility of related dates; this worksheet is reviewed weekly to track PRC-004 milestones.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020126	TOP-010-1(i)	R1	Lincoln Electric System (LES)	NCR01001	04/14/2018	04/15/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 10, 2018, Lincoln Electric System (LES) submitted a Self-Log stating that, as a Transmission Operator, it was in noncompliance with TOP-010-1(i) R1. LES reported that its System Operator did not implement the LES Quality Assessment Process as required by TOP-010-1(i) R1. At 23:46 on April 14, 2018, the LES System Operator received an alarm associated with data quality issues in its state estimator. The System Operator failed to properly respond to the alarm by either correcting the issue or contacting LES engineering support to correct the issue. The cause of the noncompliance was that the System Operator failed to follow LES' documented process for addressing Real-time data quality issues. Prior to the noncompliance the System Operator had been briefed that a data quality issue would occur when a neighboring entity returned a specific transmission line to service. The System Operator mistakenly believed that because he had been briefed by the support engineer, he would not need to contact engineering support to resolve the issue once it occurred. The noncompliance started on April 14, 2018, when the LES System Operator did not implement the LES process to respond to a Real-time data quality issue, and ended on April 15, 2018 when an LES support engineer corrected the data issue in the state estimator.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Per LES, the System Operator was aware of the actual system conditions and knew the correct status of the transmission line despite the data quality issue. LES stated that the inaction by the System Operator resulted in suspect data occurring on approximately 50 analog points for 11 hours. LES reports that its state estimator calculates 1,700 data points; therefore, the suspect data was limited to 2.9% of all LES data points. LES states that a post-mortem analysis showed that all actual and calculated post-contingent flows were below actual limits. The data quality issue was related to an in-service line being indicated as out-of-service in the state estimator, which limited the impact to the BPS to potentially causing System Operator action to occur earlier than necessary (i.e. overly conservative operations). No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, LES: 1) corrected the status of the transmission line in the state estimator; 2) updated the SCADA alarm text to provide clearer guidance to System Operators on actions that need to be taken; and 3) reviewed the Quality Assessment Process and clarified language on actions that need to be taken by the System Operator in response to alarms.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020550	COM-002-4	R4	Lincoln Electric System (LES)	NCR01001	05/01/2018	05/04/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 9, 2018, Lincoln Electric System (LES) submitted a Self-Log stating that, as a Transmission Operator, it was in noncompliance with COM-002-4 R4. Per COM-002-4 R4, LES as a Transmission Operator, is required to assess its adherence to, and the effectiveness of, its communications protocol developed per R1. LES' 2017 assessments were completed on April 19, 2017, and the 2018 assessments were completed on May 4, 2018. The 2018 assessment was due prior to May 1, 2018. The cause of the noncompliance was that there was a deficiency in LES' process to ensure the communication protocol assessment was performed. Specifically, management of the timing for communication protocol assessments was contained entirely within a Microsoft Excel spreadsheet. LES had insufficient controls to ensure that it completed assessment by the deadline. The noncompliance start date is May 1, 2018, one calendar year after the 2017 assessments were completed, and the noncompliance end date is May 4, 2018, when the 2018 assessments were completed.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The noncompliance relates to an after-the-fact review of adherence to communication protocols. Additionally, the noncompliance duration was limited to 3 days. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, LES: 1) performed the assessments on all ten of its System Operators; and 2) implemented a recurring task in Microsoft Outlook to initiate completion of the COM-002-4 R4 assessments.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2017017701	PRC-023-2	R1	Northern States Power (Xcel Energy) (NSP)	NCR01020	07/01/2014	02/03/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 8, 2017, NSP, submitted a Self-Report stating that, as a Transmission Owner, it was in noncompliance with PRC-023-2 R1. NSP, Public Service Company of Colorado (PSCO) (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program. The noncompliance occurred in the operating area of SPS and the Self Report identified two instance of noncompliance. In the first instance of noncompliance, Xcel Energy states that on January 30, 2017, a relay technician performing scheduled relay maintenance noted a discrepancy between the "As-Left" settings and the actual implemented settings for a Switch-on-to-fault (SOTF) relay at a substation. It was determined that the voltage supervision setting for the SOTF relay had not been properly implemented. This instance of noncompliance was caused by a shortcoming in SPS's processes, allowing the setting change to be signed off without first being verified by the implementing technician. The noncompliance began on July 1, 2014, the effective date for SOTF relaying schemes under the phased implementation plan, and ended on February 3, 2017 when new settings were implemented. In the second instance of noncompliance, Xcel Energy states that relays utilizing PRC-023-2 Requirement R1, criteria 1 are required to be set so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit. In 2016, Xcel Energy implemented a new Transmission Facility rating system utilizing enhanced models, and the new rating system changed the Facility Ratings for many Facilities. Following the implementation of the ratings system change and the publishing of the new Facility Rating, the PRC-023 SME performed a secondary review of PRC-023 settings and determined that as a result of the new Facility Rating, the relay at one Facility was now set below the required 150% loadability factor. The cause of the noncompliance was that Xcel Energy did not follow its process to complete the secondary review of relay settings prior to the publishing of the new Facility Rating; the implementation of the new rating system resulted in a backlog of relay settings to review and it was unable to perform all the secondary reviews in a timely manner. The noncompliance began in late 2016 when the new Facility Rating was published resulting in the relay setting being below 150% of the loadability factor, and ended on April 19, 2017 when new settings were implemented. The noncompliance began on July 1, 2014, when the Standard and Requirement became effective in the first instance of noncompliance, and ended on April 19, 2017 when new settings in the second instance were implemented.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The first instance was minimal because per Xcel Energy, the load flow studies indicated that line loading of the impacted 230-kV line only exceeded the SOTF logic 0.14% of the time and SOTF logic is only enabled for the first 30-60 cycles after the breaker closes. Following an extent of condition review for all Facilities, it was determined that the noncompliance was limited to this one 230-kV line. The second instance was minimal, because per Xcel Energy, after implementing the revised ratings, the impacted relay was only 0.2% (2.5 Amps) short of the required 150% loadability factor. Additionally, an extent of condition review was conducted for all Facilities with ratings changes due to the revised ratings processes, and no other instances were identified. No harm is known to have occurred. Xcel Energy has no relevant history of noncompliance.
Mitigation	To mitigate the first instance of noncompliance, Xcel Energy: 1) engineers issued revised settings with voltage supervision for the SOTF relay; 2) technicians tested and implemented the protection scheme; 3) a new process was established that requires the relay technician to verify relay settings in the field device when completing relay testing and maintenance activities; and 4) the issue was shared among all three Xcel Energy operating companies as part of the internal lessons learned process. To mitigate the second instance of noncompliance, Xcel Energy: 1) engineers created and issued revised settings; 2) technicians implemented and tested the protection scheme; 3) shared this information among all three Xcel Energy operating companies as part of the internal lessons learned process; 4) implemented a process calling for PRC-023 documentation coordination check prior to publishing new ratings; and 5) implemented a new process that adds additional loadability margin to PRC-023 lines, so minor changes in Facility Ratings may not require relay settings changes.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020120	PRC-005-6	R3	Northern States Power (Xcel Energy) (NSP)	NCR01020	01/01/2017	10/12/2017	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 10, 2018, NSP, a Coordinated Oversight Program participant, submitted a self-log stating that, as a Generator Owner, it was in noncompliance with PRC-005-6 R3. NSP, Public Service Company of Colorado (PSCO) (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program. The noncompliance occurred in the PSCO operating area. Xcel Energy states that a relay in a backup startup transformer at one of its generation Facilities was not tested per the minimum intervals required in PRC-005-6. The cause of the noncompliance was that Xcel Energy missed a scheduled relay testing due to a plant emission issue, and they did not have sufficient internal controls to address missed testing and ensure that the testing would be rescheduled. The noncompliance began on January 1, 2017, six years following the previous successful test of the relay, and ended on October 12, 2017 when the relay and associated transformer were retired from service.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Xcel Energy reports that it determined the issue was limited to a single relay on a backup startup transformer at a single generation Facility. The transformer was only utilized if other startup transformer feeds were lost on the unit. The unit's transformer associated with this relay was retired from service due to the poor condition of the transformer. Additionally, Xcel Energy states that it conducted an extent of condition review, and determined that there were no other instances of missed testing that had not been rescheduled. No harm is known to have occurred.
Mitigation	To mitigate the noncompliance, Xcel Energy: 1) took the relay out of service; 2) added a preventative control step to the monthly compliance checklists used by all BES generation Facilities, which requires that each generation Facility certify monthly that testing was completed within the maintenance schedule intervals, or that any delayed testing is rescheduled. The checklists are reviewed monthly by the Operations Support Managers; and 3) the Energy Supply Senior Consultants will annually review the previous year's maintenance schedule in the first quarter to ensure scheduled testing was performed or rescheduled as required. This step was entered as a task in Xcel Energy's compliance control system.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020549	MOD-026-1	R6	Omaha Public Power District (OPPD)	NCR00860	02/28/2016	08/16/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 5, 2018, Omaha Public Power District (OPPD) submitted a Self-Log stating that, as a Transmission Planner, it was in noncompliance with MOD-026-1 R6. OPPD reported that its Transmission Planning department (TP) did not provide a written response to the OPPD Production Engineering & Fuels department (functioning as the Generator Owner (GO)) within 90 days of receiving verified excitation control system model and verification information for one of its units subject to MOD-026-1. The noncompliance was discovered during the 2018 Third Quarter MRO Guided Self-Certification for MOD-026-1 R2. The cause of the noncompliance was that OPPD failed to follow its documented process for responding to model verifications submitted per MOD-026-1. The noncompliance began on February 28, 2016, 91 days after receiving the verified information, and ended on August 16, 2018 when the written response was provided to the GO.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. OPPD states that the submitted model data was reviewed and evaluated for usability by OPPD per MOD-026-1 R6 within one week of being received, that the data was determined to be usable and was submitted by OPPD for inclusion in the Planning Coordinator's dynamics package. Therefore, the noncompliance was limited to OPPD failing to notify the GO that there were no usability issues with the data. Finally, OPPD conducted an extent of condition review and confirmed that all other model verifications and correspondence between the TP and GO that are required by MOD-026-1 and MOD-027-1 were present. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, OPPD: 1) provided a written response to the GO stating that the model data was usable; 2) created a Tracking and Status Schedule for the TP SMEs to make model verification steps more visible and ensure completion of the required notification; and 3) assigned an additional transmission planning engineer to be the SME for MOD-026-1 and model verification reviews.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020552	VAR-002-4.1	R2	Otter Tail Power Company (OTP)	NCR01023	05/03/2018	06/18/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 10, 2018, Otter Tail Power (OTP) submitted a Self-Log stating that, as a Generator Operator, it was in noncompliance with VAR-002-4.1 R2. During a semi-annual review of hourly data and plant operator logs, OTP found two instances where bus voltages were outside the acceptable range without the proper notification to the Transmission Operator (TOP) as required by P2.1. OTP's Standard Operating Procedure directs plant operators to notify the TOP of all unplanned voltage excursions outside the voltage bandwidth and record them in the plant operator's log. OTP staff reviewed both the plant operator and the TOP logs and found no evidence that a notification was recorded The cause of the noncompliance was that OTP determined that the System Operator was attempting to control the bus voltage, and failed to follow the process to inform the TOP of the unplanned voltage excursions once they occurred. The noncompliance was noncontiguous; the noncompliance started on May 3, 2018 when the first voltage excursion occurred, and ended on June 18, 2018 when OTP returned the bus voltage within the acceptable range in the second instance.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. OTP's system operators were monitoring the system voltage during both instances, and no operating instructions were issued by the TOP to plant personnel requesting changes in voltage. All AVRs at the generation plants were in "auto" mode throughout the periods of the two instances in question, and there were no instructions issued by OTP's Reliability Coordinator to control or change the voltage. The duration of both voltage excursions was limited to approximately two hours. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, OTP: 1) returned the bus voltage within the acceptable range; 2) added a second alarm point to the control system to notify the plant operators of the need to take action to address voltage issues; and 3) increased training for plant operators from annual to semi-annual.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020119	EOP-004-3	R3	Southern Minnesota Municipal Power Agency (SMMPA)	NCR01030	01/01/2018	07/10/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 12, 2018, Southern Minnesota Municipal Power Agency (SMMPA) submitted a Self-Report stating that as a Transmission Owner, it was in noncompliance with EOP-004-3 R3. SMMPA reports that, as a Responsible Entity, it failed to perform the contact validation for calendar year 2017. The cause of the noncompliance was that SMMPA lacked an internal control to initiate the process of validating contact information contained in the Operating Plan each calendar year. The noncompliance started on January 1, 2018, after SMMPA failed to validate the contact information during calendar year 2017, and ended on July 10, 2018, when SMMPA performed the contact validation.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. EOP-004-4 eliminated the requirement to validate the contact information contained within the Operating Plan, indicating that validating contact information was not necessary to the reliability of the bulk power system. Further, any reportable event would have likely been identified by SMMPA's Transmission Operator, who would have presumably notified the required contacts. Moreover, SMMPA reported that it had previously validated contact information for its Operating Plan in 2014, 2015, and 2016. Finally, SMMPA did not have any reportable events during the noncompliance period. No harm is known to have occurred. SMMPA has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, SMMPA: 1) validated all contact information contained within its Operating Plan.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019021497	PRC-019-2	R1.	Wheelabrator Bridgeport, L.P.	NCR02923	7/1/2016	7/22/2016	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	During a Compliance Audit conducted from January 2, 2019 through May 9, 2019, NPCC determined that Wheelabrator Bridgeport, L.P. (the entity), as a Generator Owner (GO), was in noncompliance with PRC-019-2 R1. The entity failed to confirm the coordination of the voltage regulating system controls, (including in-service limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions by July 1, 2016. The entity began work on PRC-019 evaluations in May 2016. In early June 2016, the entity decided to engage a third-party contractor to complete the review. The entity negotiated the contract for work and provided the necessary data to the contractor in early June and the purchase order was completed on June 21, 2016. The entity did not receive the completed draft report from the contractor until July 9, 2016. The final report was issued two weeks later on July 22, 2016. It confirmed the coordination and indicated that no relay setting changes were required. This noncompliance started on July 1, 2016, when the Standard and Requirement became mandatory and enforceable. The noncompliance ended on July 22, 2016, when the entity received the completed technical report. The cause of this noncompliance was a lack of internal controls to ensure PRC-019 evaluations were completed. The entity mistakenly believed it was compliant with the Standard and did not seek assistance with PRC-019 evaluations in a timely fashion before the Standard came into effect.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The failure to verify the coordination of the protection system with the in-service limiters could cause an unnecessary trip, or failure to trip of the unit, which could stress the system further. However, the entity is a 58 MW net generating facility. It has had a capacity factor of 79.5% in 2016, 89.6% in 2017, and 92.1% in 2018. The rated capability is about 2.5% of the ISONE typical required Operating Reserve (approximately 2,300 MW). ISO-New England would be able to obtain that amount of replacement operating reserve. Additionally, the required report was completed approximately three weeks after the enforcement date meaning the exposure was relatively short and the issue was largely a documentation issue. No relay setting changes were required. No harm is known to have occurred as a result of this noncompliance. NPCC considered the entity's compliance history and determined there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) received the completed draft reports confirming the coordination; 2) added maintenance and testing activities for PRC-019 to the maintenance management software; and 3) scheduled the next review six months prior to five year maximum interval.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019021498	PRC-024-2	R2	Wheelabrator Bridgeport, L.P.	NCR02923	4/1/2018	6/5/2019	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from January 2, 2019 through May 9, 2019, NPCC determined that Wheelabrator Bridgeport, L.P. (the entity), as a Generator Owner (GO), was in noncompliance with PRC-024-2 R2. The entity failed to implement relay settings to ensure that its generator voltage protective relaying does not trip its applicable generating facility within the "no trip zone" of PRC-024-2 Attachment 2. In June 2016, the entity evaluated its generator voltage protective relay settings so that its protective relaying was set so the generator voltage protecting relaying does not trip within the "no trip zone" of PRC-024-2 Attachment 2. In April 2018, during a relay upgrade, the entity changed its generator voltage protective relay settings to provide better protection for the generator. However, the entity failed to set its voltage protective relaying such that the low voltage ride-through remains outside the no-trip zone identified in the standard. Plots and settings the entity provided indicate that two points settings are on the lower voltage graph line. The lower voltage line is considered part of the "no trip zone." This noncompliance started on April 1, 2018, when the entity failed to implement relay settings that would ensure that its generator voltage protective relaying does not trip its applicable generating facility within the "no trip zone." The noncompliance ended on June 5, 2019 when the entity implemented the settings changes. The root cause of this noncompliance was a lack of understanding about the PRC-024-2 R2 Standard and Requirement. The entity did not understand that the low voltage ride-through settings could not be directly on the "no-trip" line.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Noncompliance with PRC-024-2 R2 could result in trips that would otherwise not occur and capacity loss during a system voltage excursion event, which would further stress the system during a contingency. This noncompliance consisted of incorrect voltage protective relaying settings that would trip the entity's generating units within the "No Trip Zone" of Attachment 2. To achieve compliance, the entity implemented changes to the tripping point of the undervoltage element (27) as summarized below: Relay / Protective Element / Noncompliant Setting (Existing Setting) / Compliant Setting (Implemented) SEL-751A / Undervoltage (27) / 0.75V@2 sec. / 0.74V@2 sec. SEL-751A / Undervoltage (27) / 0.45V@0.2 sec. / 0.44V@0.2 sec. However, the entity is a 58 MW net generating facility. It has had a capacity factor of 79.5% in 2016, 89.6% in 2017 and 92.1% in 2018. The rated capability of the site is 2.5% of the ISONE typical Operating Reserve (approximately 2,300 MW). ISONE would be able to obtain that amount of replacement operating reserve. No harm is known to have occurred as a result of this issue of noncompliance. NPCC considered the entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) updated the required undervoltage relay setting below the "no trip" line; 2) coordinated the setting changes with the Transmission Owners and Reliability Coordinator; 3) instituted monitoring by plant personnel and compliance consultants of PRC-024 Standard for future changes.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019021495	MOD-032-1	R2.	Wheelabrator Saugus J.V.	NCR10033	4/16/2017	4/12/2019	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	During a Compliance Audit conducted from January 2, 2019 through May 9, 2019, NPCC determined that Wheelabrator Saugus J.V. (the entity), as a Generator Owner (GO), was in noncompliance with MOD-032-1 R2. The entity failed to provide its Transmission Planner (TP)/Planning Coordinator (PC) ISO-New England with required dynamics data in 2017 by the original due date requested by the TP/PC. In March 2017, ISO-New England requested dynamics data from the entity by April 16, 2017. The entity mistakenly believed that 2017 dynamics data certification had been completed and submitted to ISO-NE for them by their lead market participant (Wheelabrator North Andover). However, the lead market participant only certified for their own plant and not the Saugus plant. ISO-NE never received a dynamic data certification from the entity in 2017. ISO-NE did not request dynamics data certification in 2018 or 2019. The entity was recertified on April 12, 2019 in conjunction with discussions with ISO-NE. The recertification indicated that there were no changes to the dynamics data on file between January 2016 and April 2019. The noncompliance started on April 16, 2017, when the entity failed to provide its TP/PC with the required dynamics data by the requested due date. The noncompliance ended on April 12, 2019 when the dynamics data was recertified. The root cause of this noncompliance was the lack of effective internal controls to ensure dynamics data was transmitted to the TP/PC in a timely fashion. Confusion between the entity and the lead market participant served as a contributing cause.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Timely submission of data is critical in the development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system. However, the entity is a 36.9 MW generating Facility. It has had a capacity factor of 80.9% in 2016, 78.4% in 2017, and 79.1% in 2018. The rated capability is about 1.6% of the ISONE typical required Operating Reserve (approximately 2,300 MW). ISO-New England would be able to obtain that amount of replacement operating reserve. Additionally, based on the report, there were no changes to the dynamic data from 2016 through 2019, which reduces the potential impact to the BES for the failure to report in 2017. No harm is known to have occurred as a result of this noncompliance. NPCC considered the entity's compliance history and determined there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) submitted the recertified dynamics data to ISO-NE; and 2) scheduled recertification dates in Plant Monthly NERC Compliance Report.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019021496	PRC-019-2	R1.	Wheelabrator Saugus J.V.	NCR10033	7/1/2016	7/22/2016	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from January 2, 2019 through May 9, 2019, NPCC determined that Wheelabrator Saugus J.V. (the entity), as a Generator Owner (GO), was in noncompliance with PRC-019-2 R1. The entity failed to confirm the coordination of the voltage regulating system controls, (including in-service limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions by July 1, 2016. The entity began work on PRC-019 evaluations in May 2016. In early June 2016, the entity decided to engage a third-party contractor to complete the review. The entity negotiated the contract for work and provided the necessary data to the contractor in early June and the purchase order was completed on June 21, 2016. The entity received the completed draft report from the contractor on July 12, 2016. The final report was issued ten days later on July 22, 2016. It confirmed the coordination and indicated that no relay setting changes were required. This noncompliance started on July 1, 2016, when the Standard and Requirement became mandatory and enforceable. The noncompliance ended on July 22, 2016, when the entity received the completed technical report. The cause of this noncompliance was a lack of internal controls to ensure PRC-019 evaluations were completed. The entity mistakenly believed it was compliant with the Standard and did not seek assistance with PRC-019 evaluations in a timely fashion before the Standard came into effect.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The failure to verify the coordination of the protection system with the in-service limiters could cause an unnecessary trip, or failure to trip of the unit, which could stress the system further. However, the entity is a 36.9 MW generating Facility. It has had a capacity factor of 80.9% in 2016, 78.4% in 2017, and 79.1% in 2018. The rated capability is about 1.6% of the ISONE typical required Operating Reserve (approximately 2,300 MW). ISO-New England would be able to obtain that amount of replacement operating reserve. Additionally, the required report was completed approximately three weeks after the enforcement date meaning the exposure was relatively short and the issue was largely a documentation issue. No relay setting changes were required. No harm is known to have occurred as a result of this noncompliance. NPCC considered the entity's compliance history and determined there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) received the completed draft reports confirming the coordination; 2) added maintenance and testing activities for PRC-019 to maintenance management software; and 3) scheduled the next review at least six months prior to five year maximum interval.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019021571	PRC-019-2	R1.	Wheelabrator Westchester Inc.	NCR10221	7/1/2016	7/22/2016	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	During a Compliance Audit conducted from January 2, 2019 through May 13, 2019, NPCC determined that Wheelabrator Westchester Inc. (the entity), as a Generator Owner (GO), was in noncompliance with PRC-019-2 R1. The entity failed to confirm the coordination of the voltage regulating system controls, (including in-service limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions by July 1, 2016. The entity began work on PRC-019 evaluations in May 2016. In early June 2016, the entity decided to engage a third-party contractor to complete the review. The entity negotiated the contract for work and provided the necessary data to the contractor in early June and the purchase order was completed on June 21, 2016. The entity received the completed draft report from the contractor on July 13, 2016. The final report was issued two weeks later on July 22, 2016. It confirmed the coordination and indicated that no relay setting changes were required. This noncompliance started on July 1, 2016, when the Standard and Requirement became mandatory and enforceable. The noncompliance ended on July 22, 2016, when the entity received the completed technical report. The cause of this noncompliance was a lack of internal controls to ensure PRC-019 evaluations were completed. The entity mistakenly believed it was compliant with the Standard and did not seek assistance with PRC-019 evaluations in a timely fashion before the Standard came into effect.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The failure to verify the coordination of the protection system with the in-service limiters could cause an unnecessary trip, or failure to trip of the unit, which could stress the system further. However, the entity is a single 59.5 MW waste-to-energy generating Facility. It has had a capacity factor of 81.6% in 2016, 81.8% in 2017, and 80.2% in 2018. The rated capability is about 2.5% of the ISONE typical required Operating Reserve (approximately 2,300 MW). ISO-New England would be able to obtain that amount of replacement operating reserve. Additionally, the required report was completed approximately three weeks after the enforcement date meaning the exposure was relatively short and the issue was largely a documentation issue. No relay setting changes were required. No harm is known to have occurred as a result of this noncompliance. NPCC considered the entity's compliance history and determined there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) received the completed draft reports confirming the coordination; 2) added maintenance and testing activities for PRC-019 to maintenance management software; and 3) scheduled the next review at least six months prior to five year maximum interval.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019021590	PRC-019-2	R1.	Wheelabrator Millbury Inc.	NCR10172	7/1/2016	7/22/2016	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	During a Compliance Audit conducted from March 14, 2019 through May 16, 2019, NPCC determined that Wheelabrator Millbury Inc. (the entity), as a Generator Owner (GO), was in noncompliance with PRC-019-2 R1. The entity failed to confirm the coordination of the voltage regulating system controls, (including in-service limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions by July 1, 2016. The entity began work on PRC-019 evaluations in May 2016. In early June 2016, the entity decided to engage a third-party contractor to complete the review. The entity negotiated the contract for work and provided the necessary data to the contractor in early June and the purchase order was completed on June 21, 2016. The entity received the completed draft report from the contractor on July 11, 2016. The final report was issued two weeks later on July 22, 2016. It confirmed the coordination and indicated that no relay setting changes were required. This noncompliance started on July 1, 2016, when the Standard and Requirement became mandatory and enforceable. The noncompliance ended on July 22, 2016, when the entity received the completed technical report. The cause of this noncompliance was a lack of internal controls to ensure PRC-019 evaluations were completed. The entity mistakenly believed it was compliant with the Standard and did not seek assistance with PRC-019 evaluations in a timely fashion before the Standard came into effect.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The failure to verify the coordination of the protection system with the in-service limiters could cause an unnecessary trip, or failure to trip of the unit, which could stress the system further. However, the entity is a 47.6 MW generating Facility. It has had a capacity factor of 91.1% in 2016, 82.9% in 2017, and 88.8% in 2018. The rated capability is about 2% of the ISONE typical required Operating Reserve (approximately 2,300 MW). ISO-New England would be able to obtain that amount of replacement operating reserve. Additionally, the required report was completed approximately three weeks after the enforcement date meaning the exposure was relatively short and the issue was largely a documentation issue. No relay setting changes were required. No harm is known to have occurred as a result of this noncompliance. NPCC considered the entity's compliance history and determined there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) received the completed draft reports confirming the coordination; 2) added maintenance and testing activities for PRC-019 to maintenance management software; and 3) scheduled the next review at least six months prior to five year maximum interval.

ReliabilityFirst Corporation (ReliabilityFirst) Compliance Exception O&P

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020028	MOD-026-1	R2	Cambria Cogen Company	NCR00705	7/1/2018	9/24/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On July 5, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-026-1 R2. On April 28, 2018, the entity contracted with a third party engineering firm to perform testing and modeling for MOD-026-1. The third party engineering firm completed physical testing and field verification on June 17, 2018. Subsequently, however, the engineering firm notified the entity that it would not be able to complete the subsequent modeling required by the Standard by the July 1, 2018 deadline. Upon receiving this notification, the entity notified PJM that the modeling would be delayed. The root cause of this noncompliance was the entity's inability to guarantee that the third party would complete the subsequent modeling required by the July 1, 2018 deadline. This root cause involves the management practice of external interdependencies, which includes managing performance of third parties. This noncompliance started on July 1, 2018, when the entity was required to comply with MOD-026-1 R2 and ended on September 24, 2018, when the entity completed the testing and modeling and notified PJM.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by not having the generator excitation control system or plant volt/var control function model and the model parameters used in dynamic simulations accurately represented when assessing BPS reliability could have potentially affected the reliable operation of the BPS. This risk was mitigated in this case by the following factors. First, the entity completed the work less than three months late, which reduced the amount of time that it could have had an adverse impact. Second, the entity notified PJM that the modeling would be delayed. So, PJM was aware of the issue. No harm is known to have occurred ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity contracted a third party engineering firm to perform testing and modeling for MOD-027-1 and forwarded data to PJM. ReliabilityFirst has verified the completion of all mitigation activity.

ReliabilityFirst Corporation (ReliabilityFirst) Compliance Exception O&P

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020027	MOD-027-1	R2	Cambria Cogen Company	NCR00705	7/1/2018	9/24/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On July 5, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-027-1 R2. On April 28, 2018, the entity contracted with a third party engineering firm to perform testing and modeling for MOD-027-1. The third party engineering firm completed physical testing and field verification on June 17, 2018. Subsequently, however, the engineering firm notified the entity that it would not be able to complete the subsequent modeling required by the Standard by the July 1, 2018 deadline. Upon receiving this notification, the entity notified PJM that the modeling would be delayed. The root cause of this noncompliance was the entity's inability to guarantee that the third party would complete the subsequent modeling required by the July 1, 2018 deadline. This root cause involves the management practice of external interdependencies, which includes managing performance of third parties. This noncompliance started on July 1, 2018, when the entity was required to comply with MOD-027-1 R2 and ended on September 24, 2018, when the entity completed its Mitigating Activities.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by not having the generator excitation control system or plant volt/var control function model and the model parameters used in dynamic simulations accurately represented when assessing BPS reliability could have potentially affected the reliable operation of the BPS. This risk was mitigated in this case by the following factors. First, the entity completed the work less than three months late, which reduced the amount of time that it could have had an adverse impact. Second, the entity notified PJM that the modeling would be delayed. So, PJM was aware of the issue. No harm is known to have occurred ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity contracted a third party engineering firm to perform testing and modeling for MOD-027-1 and forwarded data to PJM. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019564	TOP-001-3	R9	METC	NCR00820	1/22/2018	1/22/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On April 11, 2018, METC on behalf of itself, ITC Transmission (NCR00803), Michigan Electric Coordinated Systems (NCR08023), and ITC Interconnection LLC (NCR11638), submitted a Self-Report stating that, as a Transmission Operator, it was in noncompliance with TOP-001-3 R9. METC submitted the Self-Report to ReliabilityFirst under an existing multi-region registered entity agreement. On January 22, 2018, the Real-Time Contingency Analysis (RTCA) solution on the ITC Holdings Corp. Michigan (ITC MI) Transmission Management System (TMS) (The ITC MI TMS services the transmission systems of ITC Transmission, METC, and ITC Interconnection.) became unavailable for a period of approximately 38 minutes. The control room staff recognized that the RTCA was having issues and notified the on-call support staff. During this 38 minute time frame, the RTCA "too old" alarm alerted and cleared intermittently, causing control room staff to incorrectly assume that valid outputs were occurring intermittently. In fact, all contingency cases remained unsolved for the entire 38 minute time period. But because of the control room staff's incorrect belief that valid output were occurring intermittently, they did not take steps to notify the Reliability Coordinator (RC) of the outage of the RTCA assessment capability. The root cause of the noncompliance was the entity's failure to have sufficient procedures in place that recognize and alert control room staff that contingency cases remain unsolved, therefore preventing the control room staff from taking the steps to notify the RC of an unplanned outage. This root cause involves the management practice of reliability quality management, which includes maintaining a system for deploying internal controls. This noncompliance started on January 22, 2018, when the RTCA became unavailable for at least 30 minutes, and ended 8 minutes later, when the entity corrected the RTCA issues.
Risk Assessment	ReliabilityFirst determined that the subject noncompliance posed a minimal risk to the reliability of the bulk power system based on the following factors. The risk posed by the entity's failure to alert the RC and other known impacted entities of the RTCA issues was that it could prevent those entities from preparing for potential future post-contingent conditions. This risk was mitigated in this case by the following factors. First, the duration of the RTCA issue exceeded the reporting threshold by only 8 minutes, minimizing the number of potential post-contingent conditions. Second, both MISO and PJM indicated that their respective RTCA systems were fully functional during this noncompliance with no operating concerns. ReliabilityFirst also notes that the RC did not report any abnormal conditions during the time period ITC's RTCA was unavailable. Further, throughout the RTCA event, the ITC Companies maintained visibility through the Supervisory Control and Data Acquisition system, which continued to provide all line flows, voltages, frequencies, and equipment monitoring and associated alarms. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) implemented a new procedure for the on-call engineers to follow to ensure a systematic process is implemented when responding to RTCA too old conditions has been developed and reviewed with the on-call engineers; 2) developed and implemented a new high priority audible alarm to alert Operations Control Room (OCR) personnel to the existence of non-convergent RTCA contingency cases; 3) updated the Alarm Event Notifications alarms that are sent to the on-call engineer to address the loss of information associated with the truncation of critical information in the alarms when the system sends text messages; 4) requested, received and implemented additional Inter-Control Center Communication Protocol (ICCP) data points from Hydro One for the TMS State Estimator/Contingency Analysis model specifically for the area that initiated this event; 5) now consider zero solved contingencies as constituting an unavailable RTCA; 6) conducted refresher communication training to the OCR in order to highlight the need to validate assumptions with supporting subject matter experts, including the on-call engineers, to ensure the interpretation of a given situation is correct; and 7) performed training to OCR staff on the revised alarms. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019565	TOP-001-3	R13	METC	NCR00820	1/22/2018	1/22/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On April 11, 2018, METC on behalf of itself, ITC Transmission (NCR00803), and ITC Interconnection LLC (NCR11638), submitted a Self-Report stating that, as a Transmission Operator, it was in noncompliance with TOP-001-3 R13. METC submitted the Self-Report to ReliabilityFirst under an existing multi-region registered entity agreement. On January 22, 2018, the Real-Time Contingency Analysis (RTCA) solution on the ITC Holdings Corp. Michigan (ITC MI) Transmission Management System (TMS) (The ITC MI TMS services the transmission systems of ITC Transmission, METC, and ITC Interconnection.) became unavailable for a period of approximately 38 minutes. The control room staff recognized that the RTCA was having issues and notified the on-call support staff. During this 38 minute time frame, the RTCA "too old" alarm alerted and cleared intermittently, causing control room staff to incorrectly assume that valid outputs were occurring intermittently. In fact, all contingency cases remained unsolved for the entire 38 minute time period. Therefore, because it was believed that RTCA had valid intermittent results, no steps taken to ensure that Real-Time Assessments (RTAs) were completed via other mechanisms at least once every 30 minutes. The root cause of the noncompliance was the entities failure to have sufficient procedures in place that recognize and alert control room staff that contingency cases remain unsolved, resulting in the mistaken belief that the RTCA had valid intermittent results. This root cause involves the management practice of reliability quality management, which includes maintaining a system for deploying internal controls. This noncompliance started on January 22, 2018, when the RTCA became unavailable for at least 30 minutes, and ended 8 minutes later, when the entity corrected the RTCA issues.
Risk Assessment	ReliabilityFirst determined that the subject noncompliance posed a minimal risk to the reliability of the bulk power system based on the following factors. The risk posed by the entity's failure to ensure that a RTA was performed at least every 30 minutes was that it could prevent those entities from preparing for potential future post-contingent conditions. This risk was mitigated in this case by the following factors. First, the duration of the RTCA issue exceeded the reporting threshold by only 8 minutes, minimizing the number of potential post-contingent conditions. Second, both MISO and PJM indicated that their respective RTCA systems were fully functional during this noncompliance with no operating concerns. ReliabilityFirst also notes that the Reliability Coordinator did not report any abnormal conditions during the time period ITC's RTCA was unavailable. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) implemented a new procedure for the on-call engineers to follow to ensure a systematic process is implemented when responding to Real Time Contingency Analysis (RTCA) too old conditions has been developed and reviewed with the on-call engineers; 2) developed and implemented a new high priority audible alarm to alert Operations Control Room (OCR) personnel to the existence of non-convergent RTCA contingency cases; 3) updated the Alarm Event Notifications alarms that are sent to the on-call engineer to address the loss of information associated with the truncation of critical information in the alarms when the system sends text messages; 4) requested, received and implemented additional Inter-Control Center Communication Protocol (ICCP) data points from Hydro One for the Transmission Management System (TMS) State Estimator/Contingency Analysis model specifically for the area that initiated this event; 5) now consider zero solved contingencies as constituting an unavailable RTCA; 6) conducted refresher communication training to the OCR in order to highlight the need to validate assumptions with supporting subject matter experts, including the on-call engineers, to ensure the interpretation of a given situation is correct; and 7) performed training to OCR staff on the revised alarms. ReliabilityFirst has verified the completion of all mitigation activity.

ReliabilityFirst Corporation (ReliabilityFirst) Compliance Exception O&P

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019566	NUC-001-3	R4	METC	NCR00820	1/22/2018	1/22/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On April 11, 2018, METC on behalf of itself and ITC Transmission (NCR00803), submitted a Self-Report stating that, as a Transmission Owner, Transmission Operator and Transmission Planner, it was in noncompliance with NUC-001-3 R4. METC submitted the Self-Report to ReliabilityFirst under an existing multi-region registered entity agreement. On January 22, 2018, the Real-Time Contingency Analysis (RTCA) solution on the ITC Holdings Corp. Michigan (ITC MI) Transmission Management System (TMS) (The ITC MI TMS services the transmission systems of ITC Transmission, METC, and ITC Interconnection.) became unavailable for a period of approximately 38 minutes. The control room staff recognized that the RTCA was having issues and notified the on-call support staff. During this 38 minute time frame, the RTCA "too old" alarm alerted and cleared intermittently, causing control room staff to incorrectly assume that valid outputs were occurring intermittently. In fact, all contingency cases remained unsolved for the entire 38 minute time period. ITC has a Nuclear Plant Operating Agreement with DTE Energy's Enrico Fermi 2 Nuclear Power Plant. ITC is required to notify the plant and MISO whenever ITC loses the ability to monitor or predict the operation of the transmission system affecting off-site power to Fermi Plant. Section 3.1.3 states, "METC shall notify MISO should its ability to predict the post-contingent operation of the transmission system at Palisades Nuclear Generating Plant switchyard become disabled." In addition Section 6.1.3 of the Nuclear Plant Interface Coordination Agreement specifically states, "ITC shall immediately notify the Fermi 2 Nuclear Power Plant staff, MISO, DTEE SOC, if an outage of its RTCA lasts 30 minutes or longer." The outage exceeded the 30 minute threshold by approximately 8 minutes. The root cause of the noncompliance was the entity's failure to have sufficient procedures in place that recognize and alert control room staff that contingency cases remain unsolved, therefore preventing the control room staff from taking the steps to notify the appropriate nuclear plant and MISO of the loss of the ability to monitor/predict the operation of the transmission system affecting off-site power to Fermi Plant. This root cause involves the management practice of reliability quality management, which includes maintaining a system for deploying internal controls. This noncompliance started on January 22, 2018, when the RTCA became unavailable for at least 30 minutes, and ended 8 minutes later, when the entity corrected the RTCA issues.
Risk Assessment	ReliabilityFirst determined that the subject noncompliance posed a minimal risk to the reliability of the bulk power system based on the following factors. The risk posed by the entity's failure to ensure that a Real-Time Assessment was performed at least every 30 minutes was that it could prevent those entities from preparing for potential future post-contingent conditions. This risk was mitigated in this case by the following factors. First, the duration of the RTCA issue exceeded the reporting threshold by only 8 minutes, minimizing the number of potential post-contingent conditions. Second, both MISO and PJM indicated that their respective RTCA systems were fully functional during this noncompliance with no operating concerns. ReliabilityFirst also notes that the Reliability Coordinator did not report any abnormal conditions during the time period ITC's RTCA was unavailable. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) implemented a new procedure for the on-call engineers to follow to ensure a systematic process is implemented when responding to RTCA too old conditions has been developed and reviewed with the on-call engineers; 2) developed and implemented a new high priority audible alarm to alert Operations Control Room (OCR) personnel to the existence of non-convergent RTCA contingency cases; 3) updated the Alarm Event Notifications alarms that are sent to the on-call engineer to address the loss of information associated with the truncation of critical information in the alarms when the system sends text messages; 4) requested, received and implemented additional Inter-Control Center Communication Protocol (ICCP) data points from Hydro One for the TMS State Estimator/Contingency Analysis model specifically for the area that initiated this event; 5) now consider zero solved contingencies as constituting an unavailable RTCA; 6) conducted refresher communication training to the OCR in order to highlight the need to validate assumptions with supporting subject matter experts, including the on-call engineers, to ensure the interpretation of a given situation is correct; and 7) performed training to OCR staff on the revised alarms. ReliabilityFirst has verified the completion of all mitigation activity.

ReliabilityFirst Corporation (ReliabilityFirst) Compliance Exception O&P

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020433	TOP-003-3	R1	PJM Interconnection, LLC (PJM)	NCR00879	1/1/2017	9/27/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On September 18, 2018, the entity submitted a Self-Report stating that, as a Transmission Operator (TOP), it was in noncompliance with TOP-003-3 R1. The entity did not maintain an adequate documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. More specifically, the entity did not include provisions in its data specification for notification of current Protection System and Special Protection System status or degradation that impacts System reliability. The issue was discovered in March, 2018, after Baltimore Gas & Electric (BGE), a Transmission Owner (TO), failed to notify the entity of a Protection System failure in a timely manner. Specifically, on March 12, 2018, at 2219 hours, BGE experienced a protection failure. BGE corrected the issue on March 13, 2018, at 1123 hours. BGE notified the entity of the issue on March 14, 2018, at 0817 hours. The delayed notification was based, in part, on the entity's failure to set forth clear notification instructions and procedures in violation of TOP-003-3 R 1.2. The root cause of this noncompliance was the entity's lack of awareness of (a) the retirement of PRC-001-1.1(ii) R2 and (b) the scope of TOP-003-3 R1. PRC-001-1.1(ii) R2 became inactive on March 31, 2017, and it used to require the reporting of relay or equipment failures to reliability entities. The entity had developed provisions in its manuals and TO/TOP matrix based upon PRC-001-1.1(ii) R2. TOP-003-3 R1 became effective on January 1, 2017, and required the entity to maintain a documented specification that included, in part, provisions requiring the reporting of similar information (i.e., "provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability"). The entity developed a documented specification and included it as an attachment to PJM Manual 001, but overlooked this particular aspect of TOP-003-3 R1. This noncompliance implicates the management practice of workforce management. Workforce management includes promoting awareness and implementing effective processes, procedures, and controls in an effort to minimize human factor issues, such as overlooking the retirement, or failing to account for all aspects, of standards and requirements. This noncompliance started on January 1, 2017, when the entity was required to comply with TOP-003-3 R1 and ended on September 27, 2018, when the entity updated its data specification.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk of this noncompliance is having an incorrect or incomplete model of existing system conditions, which could adversely affect a TOP's ability to conduct required analyses and operate the system reliably. The risk was mitigated by the following factor. During the period of this noncompliance, a separate manual (PJM Manual 03) and the entity's TO/TOP matrix addressed the reporting of Protection System outages. Restated, even though the Protection System provisions were not in the entity's data specification, the entity maintained provisions elsewhere requiring the reporting of similar information, and BGE acknowledged the existence of these separate provisions. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) updated the documented specification in Manual 001 to include reporting of protection real-time outages and planned outages; and 2) enhanced its NERC Standards status monitoring by recording the current status of all applicable standards and requirements and periodically checking the posted standards against the recorded status.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017016783	FAC-008-3	R6	Duke Energy Progress, LLC (DEP)	NCR01298	3/28/2014	01/11/2017	On-site Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a multi-regional registered entity Compliance Audit conducted from September 6, 2016 to January 11, 2017, SERC determined that Duke Energy Florida (DEF), as a Transmission Owner, was in noncompliance with FAC-008-3 R6. DEF did not include certain bus elements in its Facility Ratings determination for one transmission facility. SERC conducted a random sampling review of evidence of DEF's determination of Facility Ratings for the Suwannee River Plant, which included the Facility Ratings Sheets for the single bus configuration. The Facility Rating Sheets dated March 28, 2014 did not include the bus conductor for 115kV buses. Specifically, the 115kV transmission line Facility Ratings included substation equipment up to and including the bus side disconnect switches for four line circuit breakers, but did not include the bus elements beyond those four switches. DEF did not include four 795 all aluminum conductor (AAC) bus elements connecting to four separate 115 kV transmission lines in its Facility Rating determination to the single bus. DEF did include and correctly considered the other elements that were the most limiting elements in all four Facility Ratings. SERC conducted a random sampling review of other substations and their associated bus configurations but did not identify any other instances of noncompliance. This noncompliance started on March 28, 2014, the earliest known date when DEF's Facility Ratings spreadsheet did not include four 795 AAC conductor elements, and end on January 29, 2018, when DEF included the conductor elements in its Facility Ratings spreadsheet. The root cause of this violation was a deficient Facility Ratings Methodology procedure such that it did not define how its Transmission Substation and Line Engineering standards do not allow limit jumpers and span buses to limit the facilities ratings of the equipment when used to connect significant transmission elements.
Risk Assessment	This noncompliance posed a risk and did not pose a serious or substantial risk to the reliability of the bulk power system. DEF's failure to properly determine Facility Ratings could have resulted in inadequate operational planning, incorrect response to contingencies, and reduced equipment lifetimes. Notwithstanding, this noncompliance only affected 115 kV buses at a single substation and did not affect the most limiting element of the facility. The noncompliance did not require revising Facility Ratings or planning models and Real Time operating tools. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, DEF: 1) updated its Facility Ratings spreadsheet to include the missing 795 AAC bus elements; 2) evaluated system 3 lines to find BES Florida substations with single bus – single breaker scheme as Suwanee River Plant substation; 3) field verified the BES 115kV bus sections at Suwanee River Plant substation; 4) updated the 3-line diagram upon completion of field verification, and updated the Suwanee River Plant substation 3-line diagram as needed; 5) reviewed and updated all Suwanee River Plant substation BES Facility Ratings spreadsheet to match revisions to 3-line diagrams made during field review and communicated such changes to Planning and Operations as needed; 6) revised its Facility Ratings Methodology procedure to require the review of jumper and span bus ratings associated with the equipment they are connecting to ensure that ratings are sufficient to not become a rating limit; 7) developed workplace guidelines for the FAC 008 process; and 8) conducted training on updated guidelines.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018019366	PRC-005-6	R3	Entergy - Fossil & Hydroelectric Generation (EntergyFHG)	NCR11167	08/01/2017 (instance one) 03/1/2018 (second instance)	11/20/2017 (first instance) 03/30/2018 (second instance)	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On March 9, 2018, EntergyFHG submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-005-6 R3. EntergyFHG stated that it failed to perform battery maintenance within the required interval. In 2015, the EntergyFHG PRC-005 implementation team selected an "Annual" Preventive Maintenance (PM) frequency, as a conservative approach, to ensure compliance with the 18-month interval for maintenance activates required by PRC-005-6. Hinds Plant is a 2 x 1 combined cycle 609 MW power plant. It uses three vented lead-acid (VLA) batteries, one for each generating unit. In January 2016, EntergyFHG performed the required maintenance on all three batteries. EntergyFHG scheduled the next maintenance in January 2017. As that date approached, EntergyFHG noted possible system constraints and conflicts with other plant outage needs, and decided to defer the maintenance to the fall 2017 plant outage. EntergyFHG believed that the "annual" maintenance schedule allowed performance of those required actions within the calendar year and overlooked the 18-month requirement. On July 7, 2017, personnel at Hinds Plant performed a quarterly compliance assessment as one of its controls in place to monitor completion of testing intervals. At that time, the battery maintenance was not past due and they did not detect a conflict with the schedule due to the misunderstanding of the "annual" maintenance requirement. On November 20, 2017, EntergyFHG completed the battery maintenance. On January 23, 2018, Hinds became aware that more than 18 months had passed between required actions while performing the compliance assessment for the first quarter of 2018. EntergyFHG realized that the same misinterpretation could have affected other PM activities scheduled at quarterly and annual intervals. EntergyFHG reviewed records for generating units, which have 18-month battery PMs, units which have 4-month battery PMs, and units which have 4-month communication device activities. Those assessments confirmed that there were no additional discrepancies. SERC determined that EntergyFHG was in noncompliance with PRC-005-6 R3 because it did not maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-4. The root cause of this noncompliance was a misunderstanding of the "annual" frequency definition and its relationship to the maximum 18-month interval. This noncompliance started on August 1, 2017, when EntergyFHG was required to have performed the required maintenance, and ended on November 20, 2017, when EntergyFHG performed the required maintenance. On April 3, 2018, EntergyFHG submitted a scope expansion stating that, as a Transmission Owner, it was in noncompliance with PRC-005-6 R3. EntergyFHG stated that it failed to perform battery maintenance within the required interval. On May 16, 2017, EntergyFHG installed two redundant VLA batteries within the new substation control house at the Powerline 500kV/161kV substation. On October 13, 2017, Entergy placed the first related Protection Systems into service and the Protection System operated on that date. EntergyFHG should have performed the first required maintenance in February, 2018. However, when EntergyFHG placed the Protection System into service, it left a field in its maintenance database with a null entry. As a result, EntergyFHG did not schedule the required four-month maintenance tasks. On March 27, 2018, an EntergyFHG Asset Management engineer identified the oversight while calculating performance metrics. EntergyFHG corrected the database entry and scheduled the maintenance. The root cause of the noncompliance was lack of training. The Planner/Scheduler did not update the Application field on the newly enabled Substation component because it was not aware of the requirement to do so and thought that entries into the Substation Batteries Equipment Tab were sufficient. EntergyFHG Transmission performed a query of all substations in the maintenance database and verified that it had assigned the correct maintenance template for each component. No other substation components were without appropriate maintenance assignment. This noncompliance started on March 1, 2018, when EntergyFHG was required to have performed the four-month maintenance, and ended on March 30, 2018, when EntergyFHG performed the maintenance tasks.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Failure to maintain generator Protection System devices could cause unnecessary unit trips or prevent unit trips when they are required. However, this noncompliance relates to a single occurrence involving three batteries at a single generator location and redundant batteries at a single transmission substation. Hinds Plant is a 2 x 1 combined cycle 609 MW power plant that operates at a 70% capacity factor on a system with a total capacity of more than 23,000 MW. All three batteries at Hinds have alarms that would alert operators in manned spaces if trouble developed. EntergyFHG was current on all intermediate maintenance and testing requirements. In addition

	to the required testing, operators perform daily surveillance of the batteries and would have observe physical abnormalities. The batteries at Powerline substation are new batteries and they are completely redundant so an unlikely early failure of one battery would not inhibit the ability of the Protection System to operate as designed. The batteries are alarmed to detect failures and grounds. After commissioning the first Protection System, EntergyFHG added additional devices in the months following, so the batteries were under regular surveillance and testing during that commissioning process. EntergyFHG incorporated a detective control that identified the noncompliance and resulted in successful restoration of compliance only one month late. Both noncompliance neither caused nor prevented any protective functions. When tested, the batteries tested satisfactorily. No harm is known to have occurred. SERC considered EntergyFHG compliance history and determined that there were no relevant instances of noncompliance. SERC considered EntergyFHG's affiliate, Entergy, PRC-005-6 R3 compliance history in determining the disposition track. Entergy's relevant prior noncompliance with PRC-005-6 R6 include(s): NERC Violation ID SERC200900275, SERC201000637, SERC2012011079, SERC2013013258, SERC2016015481, and SERC2016015689. SERC determined that Entergy's PRC-005-6 R6 compliance history should not serve as a basis for applying a penalty. Prior to September 9, 2011, SERC identified many instances of noncompliance at Entergy generation plants, including missed intervals due to scheduling errors. On September 9, 2011, EntergyFHG registered separately from the transmission and nuclear generation departments of Entergy. Since that time, Entergy and EntergyFHG have used separate programs to schedule Protection System maintenance. Other than the instant Self-Report, EntergyFHG has not self-reported prior noncompliance with PRC-005-6 or any of its predecessor versions, nor have SERC audit teams identified any related noncompliance. The instant violation is not a relic of previous noncompliance but is an unanticipated consequence of EntergyFHG attempting to be proactive in its scheduling of maintenance activities.
Mitigation	To mitigate this noncompliance, EntergyFHG: 1) issued individual corrective actions to all affected EntergyFHG units to update PM Descriptions and PM intervals from Annual Battery PMs to 18-month Battery PMs (25 units); 2) reviewed PM history on EntergyFHG units with 18-month NERC Battery PMs to validate compliance with PRC-005 interval requirements; 3) reviewed PM history on EntergyFHG units with 4-month NERC Battery PMs to validate compliance with PRC-005 interval requirements; 4) reviewed PM history on EntergyFHG units with 4-month NERC Communication Device PMs to validate compliance with PRC-005 interval requirements; 5) performed study of AIMM, an application EntergyFHG uses to schedule maintenance, to determine if scheduling tool can automatically generate due dates based on last performed maintenance (as opposed to manual triggering); 6) designed an automated weekly report from the AIMM Database that provides a list of open work requests of upcoming or recently performed PMs of NERC Components; 7) developed and shared presentation surrounding the events of this condition report with Plant managers, NERC Champions, Planner/Schedulers, Team leaders, and Production superintendents; 8) updated PM Descriptions and PM intervals from Quarterly Battery PMs to 4-month Battery PMs for all affected units (25 units); 9) updated PM Descriptions and PM intervals for NERC ACS (Associated Communication System) from Quarterly PMs to a 4-month PMs for all affected units (3 units); 10) completed recommendations from AIMM application study to modify existing PM nomenclature to reflect frequency of maintenance (i.e. -4M, -18M, etc.); 11) developed and implemented an Automated Weekly Report for all EntergyFHG sites; 12) updated the task field in the SWMS to no longer accept null values and, instead, to set as a default the most conservative maintenance template. Also to show in red in the work status report; 13) improved notification process for Planner/Schedulers to apply maintenance to newly created components in SWMS to include specific instructions when a substation component is being enabled/maintenance applied; 14) developed an automated exception report for substations which require maintenance but no maintenance task is implemented; 15) updated Entergy's procedure for Planner/Scheduler and Substation Supervisor Training, to require WebTAP training on an annual basis; 16) improved Entergy's Process for Enabling/Suspending Components and Checking Components In/Out of Service in SWMS, to enhance the emphasis on enabling substation components; 17) improved the emphasis on enabling substation components within the SERC Training for New Supervisors and Planner/Schedulers; and 18) updated SERC Training for New Supervisors and Planner/Schedulers in WebTAP and require annual completion of the training for Grid Supervisors and Planner/Schedulers.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017017377	PRC-005-6	R1	Tennessee Valley Authority (TVA)	NCR01151	01/01/2017	01/30/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On April 11, 2017, TVA submitted a Self-Report stating that, as a Distribution Provider and Transmission Owner, it was in noncompliance with PRC-005-6 R1. TVA did not establish a Protection System Maintenance Program (PSMP) for its Automatic Reclosing and Sudden Pressure Relaying identified in Section 4.2, Facilities (Applicability section of the standard). On January 11, 2017, while going through the procedure revision process, TVA determined that its Transmission and Power Supply (TPS) business unit revised its PSMP to include Automatic Reclosing and Sudden Pressure Relaying but did not get approval of the revised PSMP by the January 1, 2017 NERC implementation date. On October 18, 2016, TVA began the initial review process for the revised PSMP. On December 8, 2016, TVA began the stakeholder review period, however, it did not complete the stakeholder review during the allocated two-week stakeholder review period. On January 13, 2017, TVA resolved all stakeholder comments. On January 26, 2017, TVA issued the revised PSMP with an effective date of January 30, 2017. On July 31, 2017, TVA completed its extent-of-condition and confirmed no further gaps in its PSMP. This noncompliance started on January 1, 2017, when the Standard became mandatory and enforceable, and ended on January 30, 2017, when TVA implemented the revised PSMP. The contributing causes of this noncompliance was inadequate internal controls to ensure adherence of TVA's Administration of Standard Programs and Processes (SPP) procedure and a lack of awareness of the time sensitive regulatory obligation. The entity implemented a checklist and supplemental documentation to identify regulatory obligations prior to stakeholder review and for awareness during the standards review process.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. TVA's delay in the issuance of the revised PSMP could have had an impact to the implementation of the new maintenance requirements for Auto Reclosing and Sudden Pressure Relaying. However, this was a documentation deficiency. Although the formal approval of the PSMP was 30 days late, the PSMP had been implemented to include Automatic Reclosing and Sudden Pressure Relaying by January 1, 2017. No harm is known to have occurred. SERC considered TVA's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, TVA: 1) developed process aids to support process adherence, including: a. an aid that identifies regulatory obligations prior to Stakeholder Review and support awareness by the stakeholder during the review process, b. a checklist that requires the identification of any regulatory obligations dependent on the approval of Southwest Power Pool (SPP), and c. a cover sheet that will be used to designate SPP as having time sensitive regulatory implications, which will have regulatory "hard dates" that will accompany SPP throughout the review process. 2) conduct an extent-of-condition review to identify any gaps, and revise procedures as necessary to address any discovered gaps; 3) performed training on the requirements and expectations of the Administration of Standard Programs and Processes Procedure; and 4) issued revised Administration of Standard Programs and Processes Procedure to address use of the process aids.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017018839	FAC-009-1	R1	Virginia Electric and Power Company (VEP-Trans)	NCR01214	06/18/2007	04/16/2019	Self-Report	06/15/2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 14, 2017, VEP-Trans submitted a Self-Report stating that, as a Transmission Owner (TO), it was in noncompliance with FAC-009-1 R1. VEP-Trans did not establish Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings Methodology for a transmission line facility rating. This noncompliance spanned different versions of Standards and Requirements. FAC-009-1 R1 (retired December 31, 2012) required that TOs to "establish Facility Ratings for their solely and jointly owned Facilities that are consistent with their associated Facility Ratings Methodology." On October 24, 2017, a VEP-Trans electric transmission planning engineer was reviewing a construction substation one-line for Lakeridge substation. The engineer referred to the Facility Rating Database (FRD) to review the most limiting element of 230 kV transmission Line 237, segment 2, between Keene Mill and Lakeridge substations. The engineer discovered VEP-Trans had not recorded the line lead conductor rating at Lakeridge Substation for segment 2 of Line 237 or for segment 3 of Line 237 between Lakeridge and Possum Point Substations in the FDR. On October 26, 2017, VEP-Trans sent substation operations personnel into the field to verify the existing conductor leads. Prior to identifying the missing line lead conductor rating information at Lakeridge Substation, the most limiting element for segments 2 and 3 was recorded as the 1033.5 45/7 ACSS transmission line conductor rated at 1589 Amps. On November 14, 2017, VEP-Trans conducted a meeting amongst the relevant parties confirming the discovery of the line lead conductor at Lakeridge Substation to be 1590 AAC with a normal 1000F rating of 1519 Amps. The Lakeridge Substation is a tap substation served by Line 237, which extends between Possum Point and Braddock endpoint substations. VEP-Trans operated Line 237 without the line leads at Lakeridge Substation entered into the FRD since it constructed the line prior to June 18, 2007. VEP-Trans did not identify the instant issue during its extent-of-condition assessment for NERC violation ID SERC2014014142. In 2014, VEP-Trans performed a system wide assessment of its Facility Ratings. The individuals performing the assessment were unaware that the tap point on transmission lines serving non BES facilities might use substation rated conductors to tap into and out of the substation. The transmission line operating one-lines reviewed at that time only identify transmission line rated conductors. The one-lines did not identify any substation rated conductors. The only way to have been aware of this issue would have been to review each tapped substation one-line to determine if VEP-Trans used substation conductors as line leads to tap into and out of the tap point at the substation. VEP-Trans did not do this as part of the 2014 Facility Ratings review. VEP-Trans did complete this tap-point walk-down for the instant noncompliance. VEP-Trans identified 16 instances where VEP-Trans failed to consider the line lead conductor rating. In all instances, the line lead conductor became the Most Limiting Element of the Facility. The largest Facility Rating change as a result of the line lead consideration was a 37% derate. The maximum Facility loading was 128% of the correct Facility Rating for the impacted Facilities. Only one line exceeded its current rating (by 28%), but for only one hour. During the course of VEP-Trans' tap point mitigation, VEP-Trans discovered that two bundled transmission line conductors transitioned to a single conductor on a unique style switch just outside of a certain station. Due to the limited bending radius on these switches, VEP-Trans used a single conductor to jumper to the switch. VEP-Trans completed an assessment of the scope of the switch configuration instances. VEP-Trans identified five instances when VEP-Trans failed to consider the switch configuration. In all instances, the switch became the Most Limiting Element of the Facility. The largest Facility Rating change as a result of the switch consideration was a 5% derate. The maximum Facility loading was 97% of the correct Facility Rating for the impacted Facilities. In addition, VEP-Trans identified four other instances in which the line segments contained multiple conductor types and VEP-Trans failed to identify the most limiting conductor rating for the particular line. The largest Facility Rating change as a result of the switch consideration was a 27% derate. The maximum Facility loading was 59% of the correct Facility Rating for the impacted Facilities. This noncompliance started on June 18, 2007, when the Standard became mandatory and enforceable, and ended on April 16, 2019, when VEP-Trans revised the last incorrect Facility Rating. The root cause of these instances was ineffective internal controls to prevent and detect human performance errors.

Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. VEP-Trans's failure to establish Facility Ratings that were consistent with its Facility Ratings methodology led to the misidentification of the most limiting element at 25 transmission facilities and the establishment of incorrect Facility Ratings. The errors in Facility Ratings could have resulted in erroneous outage planning, violations of System Operating Limits, and damage to Facilities. However, the VEP-Trans EMS system has alarming set at 90% of its rating for any action needed by the System Operators. VEP-Trans reviewed the operating records for all the derated Facilities and found that none had operated at loads greater than the revised Facility Ratings with the exception of one line lead, which exceeded its current rating by 28% for one hour. VEP-Trans found that the peak loading for the Facilities that it derated ranged from 37% to 128% of the revised normal Facility Rating and only three of those Facilities operated at a load greater than 90% of the revised normal Facility Rating. As a practice, VEP-Trans also performs annual Infrared (IR) Heat Scans on substation equipment during the hottest summer days. The IR scan at the substation where the load exceeded the current rating indicated no overheating issues. In addition, VEP-Trans identified only 25 instances of incorrect Facility Ratings. For the five instances related to the switches, VEP-Trans sized the single conductor to provide a capacity comparable to the bundled line conductor however the single conductor is not an exact match to the bundled conductor. No harm is known to have occurred. SERC considered VEP-Trans' FAC-009-1 R1 and FAC-008-3 R6 compliance history. VEP-Trans' relevant prior noncompliance with FAC-009-1 R1 includes: NERC Violation ID SERC2017018329, SERC2014014142, and SERC2012011536. In all three instances, the cause of the noncompliance was different from the cause of the instant issue; therefore, the mitigation in the prior instances would not have prevented the current instances. In addition, the current instances occurred in June 2007, which is prior to the implementation of the mitigation plans for the previous instances of noncompliance.
Mitigation	To mitigate this noncompliance, VEP-Trans: 1) ensured Line Facility Ratings are equal the most limiting element: upon completion of the line assessment at non BES station tap points and switches on lines with bundled conductors, Thermal Equipment Ratings Monitor (TERM) Tickets were submitted to PJM to ensure the Facility Ratings were consistent with the most limiting element; 2) conducted Facility Ratings training: Provide awareness training to the Electric Transmission Planning employees regarding the potential use of substation rated conductors at tap points serving non BES substations and the appropriate conductor selection on segments with multiple conductors; and 3) established and implemented new Transmission Line one-line diagram internal controls: The Transmission Lines Department has incorporated a notation on the transmission line one-line diagram indicating whether Substation Department conductors are used at tap points serving non BES substations and whether a single conductor switch lead is used on bundled conductor lines. VEP-Trans revised the Transmission Line Department's procedures to reflect these situations to ensure one line accuracy going forward. Upon approval of the revised procedures, the VEP-Trans Transmission Line Department conducted training with the appropriate personnel.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018019688	PRC-004-5(i)	R1	American Electric Power Service Corp as agent for AEP Texas Inc. and Public Service Company of Oklahoma (AEPSC)	NCR04006	10/31/2017	01/02/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On May 15, 2018, American Electric Power Service Corp as agent for AEP Texas Inc. and Public Service Company of Oklahoma (AEPSC) submitted a Self-Report stating that, as a Transmission Owner (TO), it was in noncompliance with PRC-004-5(i) R1. Specifically, AEPSC failed to identify whether its Protection System caused a Misoperation within 120 calendar days of a BES interrupting device operation. On July 02, 2017, an AEPSC lockout relay (LOR) tripped a 138kV circuit breaker open for the North Edinburg – Magic Valley Energy Center (MVEC) Calpine Unit 3 line as a result of a signal received from a Composite Protection System owned by AEPSC and Calpine. As a result, AEPSC was required to perform an analysis on or before October 30, 2017, which was 120 calendar days following the BES interrupting device operation, to identify whether its Protection System caused a Misoperation. However, AEPSC did not complete an analysis until January 02, 2018. AEPSC determined that its portion of the Composite Protection System operated properly (no Misoperation) in response to a relay trip caused by the interconnected entity's portion of the Composite Protection System. The issue was discovered on December 20, 2017, when Calpine contacted AEPSC regarding the BES interrupting device operation. The next day, a member of AEPSC's engineering staff confirmed the BES interrupting device operation by reviewing the Supervisory Control and Data Acquisition (SCADA) log. However, the alarm associated with the event had not been properly recorded in the appropriate operating and outage reporting databases, which would have alerted AEPSC personnel of the need to investigate the event. The root cause of this noncompliance is that the LOR alarm associated with the BES interrupting device was not properly categorized at AEPSC's Transmission Dispatch Center (TDC). Critical LOR alarms are to be included in a high priority category. However, the LOR alarm associated with the BES interrupting device was incorrectly included in a category that is not high priority. This resulted in the BES interrupting device operation not being logged in the appropriate databases by the TDC and so AEPSC was unaware of the need to identify whether a Misoperation occurred and did not follow its process for compliance with PRC-004-5(i). The noncompliance started on October 31, 2017, which is the first day after the 120th calendar day following the BES interrupting device operation. The noncompliance ended on January 02, 2018, when AEPSC completed its analysis and determined that its Protection System did not cause a Misoperation. The duration of the noncompliance was 63 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk posed by a failure to timely investigate a BES interrupting device operation is that AEPSC would not be aware of a potential Protection System Misoperation and would therefore be unable to remediate the issue. The risk was minimized by the following factors. First, after conducting its analysis, AEPSC did not identify any Misoperation. Second, the duration of the noncompliance was short, lasting 63 days. Third, AEPSC has a process in place to track the analysis and notification of BES interrupting device operations, including tracking due dates. No harm is known to have occurred. Texas RE considered AEPSC's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, AEPSC: 1) investigated the BES interrupting device operation to determine if a Misoperation occurred; 2) verified that all LOR alarms are properly categorized and created an audible alarm; 3) conducted an extent of condition review to identify any missed BES interrupting device operations for analysis; 4) created templates to be used when an alarm is created to ensure that LOR alarms are assigned the correct category; 5) implemented a peer review process for the new alarm templates to ensure accuracy prior to implementation; and 6) implemented a quarterly review to ensure all LOR alarms are properly categorized. Texas RE has verified completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018019689	PRC-004-5(i)	R2; R2.1	American Electric Power Service Corp as agent for AEP Texas Inc. and Public Service Company of Oklahoma (AEPSC)	NCR04006	10/31/2017	01/02/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On May 15, 2018, American Electric Power Service Corp as agent for AEP Texas Inc. and Public Service Company of Oklahoma (AEPSC) submitted a Self-Report stating that, as a Transmission Owner (TO), it was in noncompliance with PRC-004-5(i) R2. Specifically, AEPSC failed to provide notification of a BES interrupting device operation by a shared Composite Protection System within 120 calendar days of the operation, as required by PRC-004-5(i) R2.1. On July 02, 2017, an AEPSC lockout relay (LOR) tripped a 138kV circuit breaker open for the North Edinburg – Magic Valley Energy Center (MVEC) Calpine Unit 3 line as a result of a signal received from a Composite Protection System owned by AEPSC and Calpine. However, the alarm associated with the event had not been properly recorded in the appropriate AEPSC operating and outage reporting databases. As a result, the appropriate AEPSC personnel were not aware of the operation and AEPSC did not follow its process for compliance with PRC-004-5(i). AEPSC was required to provide notification to Calpine of the BES interrupting device operation on or before October 30, 2017, which was 120 calendar days following the BES interrupting device operation. However, AEPSC did not notify Calpine until January 02, 2018. The issue was discovered on December 20, 2017, when Calpine contacted AEPSC regarding the BES interrupting device operation. The next day, a member of AEPSC's engineering staff confirmed the BES interrupting device operation by reviewing the Supervisory Control and Data Acquisition (SCADA) log. The root cause of this noncompliance is that the LOR alarm associated with the BES interrupting device was not properly categorized at AEPSC's Transmission Dispatch Center (TDC). Critical LOR alarms are to be included in a high priority category. However, the LOR alarm associated with the BES interrupting device was incorrectly included in a category that is not high priority. This resulted in the BES interrupting device operation not being logged in the appropriate databases by the TDC and so AEPSC was unaware of the need to follow its process for compliance with PRC-004-5(i). The noncompliance started on October 31, 2017, which is the first day after the 120th calendar day following the BES interrupting device operation. The noncompliance ended on January 02, 2018, when AEPSC sent notification to Calpine of the BES interrupting device operation. The duration of the noncompliance was 63 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk was minimized by the following factors. First, after conducting its analysis, AEPSC did not identify any Misoperation. Second, the other Composite Protection System owner had been aware of the BES interrupting device operation. Third, the duration of the noncompliance was short, lasting 63 days. Fourth, AEPSC has a process in place to track the analysis and notification of BES interrupting device operations, including tracking due dates. No harm is known to have occurred. Texas RE considered AEPSC's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, AEPSC: 1) notified Calpine of the BES interrupting device operation; 2) verified that all LOR alarms are properly categorized and created an audible alarm; 3) conducted an extent of condition review to identify any missed BES interrupting device operations for analysis and notification; 4) created templates to be used when an alarm is created to ensure that LOR alarms are assigned the correct category; 5) implemented a peer review process for the new alarm templates to ensure accuracy prior to implementation; and 6) implemented a quarterly review to ensure all LOR alarms are properly categorized. Texas RE has verified completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018508	BAL-001-TRE-1	R9	Brazos Electric Power Co Op, Inc. (BEPC)	NCR04015	06/06/2017	07/06/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 24, 2017, BEPC submitted a Self-Report through an existing multi-region registered entity agreement stating that, as a Generator Owner (GO), it was in noncompliance with BAL-001-TRE-1 R9. Specifically, BEPC failed to meet a minimum 12-month rolling average initial Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight Frequency Measurable Events (FMEs). On June 6, 2017, BEPC's Miller 5 generating unit reaching eight scored FMEs, the threshold for establishing a 12-month rolling average performance score for BAL-001-TRE-1 R9. However, Miller 5 unit's average initial Primary Frequency Response performance was 0.6015 - below the required 0.75. BEPC discovered the issue when scoring prior FMEs for Miller 5 and comparing them to the Electric Reliability Council of Texas (ERCOT) FME scores. The root cause of this issue was several low scores for the Miller 5 unit due to a larger ramp magnitude adjustment from data latency, resulting in the Miller 5 unit failing to meet the initial Primary Frequency Response performance score of 0.75. This noncompliance started on June 6, 2017, when the generating unit reached eight scored FMEs and had a 12-month rolling average initial PFR performance of less than 0.75, and ended on July 6, 2018, when the generating unit reached a 12-month rolling average initial PFR performance of 0.8065.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, BEPC provided evidence to show that the lower scores were due to data latency of the information reaching ERCOT for scoring and not due to poor performance of the unit. Second, the overall market frequency response in ERCOT is robust enough to ensure sufficient frequency response is available to respond to the FMEs. In particular, for the time period at issue, the ERCOT Interconnection Minimum Frequency Response (IMFR) was 381 and the average actual Interconnection Frequency Response was 906. No harm is known to have occurred. Texas RE considered BEPC's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, BEPC: 1) met the minimum 12-month rolling average initial PFR performance of 0.75 for the generating unit at issue; 2) revised the scanning methodology to improve the maximum latency; and 3) moved the generating unit at issue to its own dedicated channel to improve latency. Texas RE has verified the completion of all mitigation activities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018308	MOD-025-2	R2	City of Garland (GP&L Production)	NCR04035	07/01/2016	09/29/2016	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from August 15, 2017, through August 17, 2017, Texas RE determined that GP&L Production, as a Generator Owner (GO), was in noncompliance with MOD-025-2 R2. In particular, GP&L Production failed to verify the Reactive Power capability in accordance with MOD-025-2, Attachment 1 by July 1, 2016. The audit team noted that GP&L Production provided evidence indicating that Reactive Power capability verifications were performed prior to July 1, 2016, but that the verifications were performed for a period of 15 minutes as is required by ERCOT Protocols, instead of one hour as is required in MOD-025-2, Attachment 1. In response to questions from the audit team, GP&L Production stated that it began performing the 1-hour test, as required by MOD-025-2, Attachment 1, in the Fall of 2016. GP&L Production completed the required MOD-025-2 testing on September 19, 2016, and submitted the results to its Transmission Planner (TP) on September 29, 2016. The root cause of this noncompliance was GP&L Production's failure to implement a process to assess new or revised NERC Reliability Standards and prepare for compliance, including the updating of internal documentation to comply with the new Standard. This noncompliance started on July 1, 2016, when MOD-025-2 became effective and enforceable, and ended on September 29, 2016, when GP&L Production submitted its verification data to its TP.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. GP&L Production performed Reactive Power capability verifications in accordance with MOD-025-2, Attachment 1, 90 days after the due date specified in the MOD-025-2 Implementation Plan. Also, the Reactive Power capability demonstrated in the verifications performed was similar to the Reactive Power capability demonstrated during the Reactive Power capability verification previously performed, and the results of these previously performed verifications were submitted to a portal to which the TP has access prior to the date specified in the MOD-025-2 Implementation Plan. No harm is known to have occurred. Texas RE considered GP&L Production's and its affiliates' compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, GP&L Production: 1) completed the required Reactive Power capability verification for its applicable generation units; 2) submitted forms containing the same information identified in MOD-025-2, Attachment 2 to its TP; and 3) revised its MOD-025-2 test forms to match the 1 hour requirements of the Standard. Texas RE verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018309	MOD-025-2	R1	City of Garland (GP&L Production)	NCR04035	07/01/2016	09/29/2016	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from August 15, 2017, through August 17, 2017, Texas RE determined that GP&L Production, as a Generator Owner (GO), was in noncompliance with MOD-025-2 R1. In particular, GP&L Production failed to verify the Real Power capability in accordance with MOD-025-2, Attachment 1 by July 1, 2016. The audit team noted that GP&L Production provided evidence indicating that Real Power capability verifications were performed prior to July 1, 2016, but that the verifications were performed for a period of 15 minutes as is required by ERCOT Protocols, instead of one hour as is required in MOD-025-2, Attachment 1. In response to questions from the audit team, GP&L Production stated that it began performing the 1-hour test, as required by MOD-025-2, Attachment 1, in the Fall of 2016. GP&L Production completed the required MOD-025-2 testing on September 19, 2016, and submitted the results to its Transmission Planner (TP) on September 29, 2016. The root cause of this noncompliance was GP&L Production's failure to implement a process to assess new or revised NERC Reliability Standards and prepare for compliance, including the updating of internal documentation to comply with the new Standard. This noncompliance started on July 1, 2016, when MOD-025-2 became effective and enforceable, and ended on September 29, 2016, when GP&L Production submitted its verification data to its TP.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. GP&L Production performed Real Power capability verifications in accordance with MOD-025-2, Attachment 1, 90 days after the due date specified in the MOD-025-2 Implementation Plan. Also, the Real Power capability demonstrated in the verifications performed was similar to the Real Power capability demonstrated during the Real Power capability verification previously performed, and the results of these previously performed verifications were submitted to a portal to which the TP has access prior to the date specified in the MOD-025-2 Implementation Plan. No harm is known to have occurred. Texas RE considered GP&L Production's and its affiliates' compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, GP&L Production: 1) completed the required Real Power capability verification for its applicable generation units; 2) submitted forms containing the same information identified in MOD-025-2, Attachment 2 to its TP; and 3) revised its MOD-025-2 test forms to match the 1 hour requirements of the Standard. Texas RE verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018596	COM-002-4	R3	Duke Energy Renewables Services, LLC (DERS)	NCR11032	09/27/2016	03/11/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted per an existing multi-region registered entity agreement from August 21, 2017, through October 27, 2017, Texas RE determined that DERS, as a Generator Operator (GOP), was in noncompliance with COM-002-4 R3. Specifically, DERS did not conduct initial training for three of its operating personnel prior to those individuals receiving an oral two-party, person-to-person Operating Instruction. In total, the three operating personnel at issue received 16 Operating Instructions that were within the scope of this issue. The first instance occurred on September 27, 2016, and the final instance occurred on March 6, 2017. One of the individuals was no longer employed by DERS as of February 28, 2017. The other two individuals received the required training on March 3, 2017 and March 11, 2017, respectively. The root cause of this noncompliance is that DERS had an insufficient process for tracking and documenting the completion of the required training for new operating personnel. During the noncompliance, DERS's process relied on a checklist to track the required trainings for new operating personnel, including requiring that the checklist must be completed before operating personnel are released to perform their job responsibilities. DERS stated that it did not retain the completed checklists for the three personnel at issue, and, as a result, DERS was unable to establish whether it had conducted the initial training required by COM-002-4 R3. To prevent recurrence of this issue, DERS has implemented a new learning management system for tracking training, including creating automatic tasks for all operating personnel. This noncompliance started on September 27, 2016, when the operating personnel at issue received an oral two-party, person-to-person Operating Instruction, and ended on March 11, 2017, when DERS completed the required training for the personnel at issue.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Failure to include initial training for operating personnel before they receive an oral two-party, person-to-person Operating Instruction could limit this operator's awareness of communications protocols, which could increase the possibility of miscommunication. In addition, DERS, as a GOP, operates more than 3,100 MW of affiliated wind and solar generating Facilities, as well as other operations services provided to other third-party Facilities. However, this issue was limited to only three members of DERS's large group of operating personnel, and each of the three operators correctly performed the three-part communication procedure for oral two-party person-to-person Operating Instructions during the period in question. In addition, DERS did not receive any Operating Instructions regarding an Emergency during the duration of the noncompliance. Finally, although DERS was unable to provide documentation showing that DERS timely conducted the initial training for the three operators at issue, voice recordings demonstrate that the operators were aware of the three-part procedure for receiving Operating Instructions. No harm is known to have occurred. Texas RE considered DERS' compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, DERS: 1) trained the two individuals who continued to work for DERS; 2) implemented a revised process and new learning management system for providing and tracking personnel training, including creating an automated task for new generator operators to complete training regarding three-part communications; and 3) developed new training materials regarding three-part communications and provided the revised training to all operating personnel who can receive oral two-party, person-to-person Operating Instructions. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018020154	EOP-011-1	R3; P3.1.3	Electric Reliability Council of Texas, Inc. (ERCOT ISO)	NCR04056	06/16/2017	07/19/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 30, 2018, ERCOT ISO submitted a Self-Report to Texas RE stating that, as a Reliability Coordinator (RC), it was in noncompliance with EOP-011-1 R3. Specifically, during 2018, ERCOT ISO did not timely notify several Transmission Operators (TOPs) of the results of its review of their Operating Plans within 30 calendar days of receipt. During a Compliance Audit conducted from November 5, 2018, through November 16, 2018, Texas RE identified an additional instance of noncompliance regarding this issue that occurred in 2017. ERCOT ISO did not timely respond to eight TOPs that submitted Operating Plans during 2018. These Operating Plans were submitted to ERCOT ISO during December 2017 through February 2018. ERCOT ISO's Operations Support staff reviewed these submissions within the 30 days required by EOP-011-1 R3 and directed ERCOT ISO's Client Services staff to provide responses to the affected TOPs. However, ERCOT ISO's Client Services staff did not timely notify these TOPs of the results of ERCOT ISO's review. Instead, notifications were provided between one day late and 148 days late. During the Compliance Audit, Texas RE identified an additional instance of noncompliance regarding this issue that occurred in 2017. In that instance, the TOP had submitted an Operating Plan to ERCOT ISO on February 15, 2017, and, on March 13, 2017, ERCOT ISO timely notified the TOP of the results of ERCOT ISO's review, indicating deficiencies in the TOP's Operating Plan and requiring that the TOP resubmit a revised Operating Plan. On May 16, 2017, ERCOT ISO received the resubmitted Operating Plan, meaning that ERCOT ISO's deadline to respond regarding the resubmitted Operating Plan fell on June 15, 2017. However, ERCOT ISO did not provide the required notification to the TOP until June 16, 2017, which is one day after the 30-day deadline provided by EOP-011-1 R3. The root cause of the noncompliance is that ERCOT ISO did not have a sufficient process for timely notifying TOPs of the results of ERCOT ISO's review of submitted Operating Plans. Regarding the instances that occurred in 2018, ERCOT ISO did not have a sufficient process to ensure that its Client Services staff provide timely notifications to TOPs after Operations Support staff have completed the review of TOPs' Operating Plans. Regarding the instance that occurred in 2017. ERCOT ISO did not have a sufficient process to address resubmitted Operating Plans. ERCOT ISO uses a spreadsheet to track TOPs' Operating Plan submissions. However, ERCOT ISO's procedures did not address the 30-day deadline for reviewing and providing notifications regarding resubmitted Operating Plans, and ERCOT ISO was not aware of the need to track resubmitted Operating Plans in its tracking spreadsheet. This noncompliance started on June 16, 2017, when ERCOT ISO did not timely notify a TOP of the results of ERCOT ISO's review, and ended on July 19, 2018, when ERCOT ISO notified affected TOPs of the results of ERCOT ISO's review.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk posed by this issue is that ERCOT ISO or a TOP would not be aware of deficiencies or reliability risks in an Operating Plan. However, in this case, ERCOT ISO determined that no reliability risks were identified in any of the plans for which a response was not timely provided. No harm is known to have occurred. Texas RE considered ERCOT ISO's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, ERCOT ISO: 1) provided the required responses to the affected TOPs; 2) revised its department procedures so that Operations Support staff will communicate the review results directly to the affected TOP; and 3) revised its tracking spreadsheet to include resubmitted Operating Plans in addition to TOPs' initial submissions.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018020877	BAL-001-TRE-1	R2: P2.2	Electric Reliability Council of Texas, Inc. (ERCOT ISO)	NCR04056	11/01/2017	07/18/2017	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 21, 2018, the ERCOT ISO submitted a Self-Log stating that, as a Balancing Authority (BA), it was in noncompliance with BAL-001-TRE-1 R2, Part 2.2. Specifically, in two instances, ERCOT ISO timely calculated rolling 12-month Primary Frequency Response (PFR) data and made the calculation results available to Generator Operators (GOs), but ERCOT ISO did not timely submit the calculation results to the Compliance Enforcement Authority. Each month, ERCOT ISO is required to calculate the PFR of each generating unit/generating facility for each Frequency Measurable Event (FME) during a rolling 12-month period. By the end of the month in which the calculation results are completed, cumulative calculation results for each FME are submitted to the Compliance Enforcement Authority and made available to certain GOs. However, on June 7, 2018, ERCOT ISO compiled a PFR report that was made available to certain GOs but was not submitted to the Compliance Enforcement Authority. On July 18, 2018, which is the 18th day after the PFR report for June 2018 was due; ERCOT ISO submitted the PFR report for July 2018 to the Compliance Enforcement Authority. Due to the cumulative rolling nature of the report, the July 2018 PFR report included the information required during June 2018. ERCOT ISO personnel discovered this issue on July 19, 2018. After conducting further investigation, ERCOT ISO identified an additional instance of the same issue. Specifically, ERCOT ISO performed the PFR calculations but did not submit a PFR report to the Compliance Enforcement Authority during October 2017. On November 2, 2017, ERCOT ISO submitted the PFR report for November 2017 to the Compliance Enforcement Authority, which included the information required during October 2017. The root cause of this noncompliance was an insufficient process to ensure that PFR reports were submitted to the Compliance Enforcement Authority when the reports are made available to GOs. During the noncompliance, the manual process used by ERCOT ISO to create and submit PFR reports did not include an automatic control to ensure that calculation results are submitted or made available to appropriate entities. This noncompliance started on November 1, 2017, which is the first day following the date when the October 2017 PFR report should have been submitted to the Compliance Enforcement Authority, and ended on July 18, 2018, when the July 2018 PFR report was submitted to the Compliance Enforcement Authority.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, although ERCOT ISO did not timely submit the PFR calculation results to the Compliance Enforcement Authority, ERCOT ISO timely calculated PFR performance data and timely made the calculation results available to GOs as required by BAL-001-TRE-1 R2, Part 2.2. Second, the two instances were both short in duration, lasting for less than three weeks and for less than one week, respectively. No harm is known to have occurred. Texas RE considered ERCOT's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, ERCOT ISO: 1) submitted the required reports to the Compliance Enforcement Authority; 2) created an automated control by updating ERCOT ISO's report creation tool to check file counts in order to ensure calculation results are submitted to appropriate entities; 3) created an additional control by modifying department procedure to include sampling and verification by a second engineer to ensure files were created and made available to appropriate entities; and 4) modified department procedure to regularly create reports within the first week of every month for the preceding rolling 12-month period.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018280	PRC-024-2	R2	Hackberry Wind, LLC (HWF) (the "Entity")	NCR00210	07/01/2016	03/06/2018	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from July 25, 2017, through August 30, 2017, Texas RE determined that the Entity, as a Generator Owner (GO), was in noncompliance with PRC-024-2 R2. Specifically, the Entity failed to set its protective relaying for its wind generation such that the generator voltage protective relaying does not trip within the "no trip zone" Facility by July 1, 2016. The Compliance Audit determined that the Entity did not correctly calculate settings necessary for its protective relaying in order to comply with PRC-024-2 R2. In particular, the Compliance team noted that the Entity had calculated the settings for the protective relaying for the Facility using an incorrect voltage value. As a result, although the Entity's calculations for the protective relay with monitoring nearest to the point of interconnection appeared to show a trip time of 0.5 seconds at 9.03 p.u. and at 10.98 p.u., that protective relay was actually set to trip after 0.5 seconds at 0.903 p.u. and 1.098 p.u., respectively. Similarly, for other protective relays at the Facility, the Entity's calculations appeared to show a trip time of 0.5 seconds at 0.47 p.u., but these relays were actually set to trip after 0.5 seconds at 0.797 p.u. The root cause of this issue is that the Entity did not have a sufficient process for compliance with PRC-005-6. The Entity stated that it did not devote sufficient resources and personnel to compliance activities regarding PRC-024-2. To address this root cause, the Entity has devoted additional resources to its compliance program. This noncompliance started on July 1, 2016, when the Entity was required to have generator voltage protective relaying settings that were compliant with PRC-024-2 R2, and ended on March 6, 2018, when the Entity applied settings to its protective relaying such that the generator voltage protective relaying does not trip within the "no trip zone."
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk posed by this issue is the possibility of tripping of a generating unit within the "no trip zone." However, the risk posed by this issue is reduced based on the following factors. First, the Entity's generating Facility is relatively small, comprising a single wind generator site with a nameplate rating of 185 MVA and with a capacity factor of 31% during the noncompliance. Second, no trips or Misoperations were identified as resulting from the issues identified during the Compliance Audit. Finally, the Entity's undervoltage protection relay settings would have allowed the Facility to operate up to 0.797 p.u. for 0.5 seconds before tripping within the "no trip zone" and the overvoltage protection relay settings would have allowed the relays to operate up to 1.098 p.u. for 0.5 seconds before tripping within the "no trip zone." No harm is known to have occurred. Texas RE considered the Entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the Entity: 1) implemented settings that were compliant with PRC-024-2 R2; 2) conducted training for the Entity's employees, including an overview of applicable Reliability Standards; and 3) obtained additional personnel and consulting services to improve its compliance program. Texas RE verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018282	PRC-005-6	R1	Hackberry Wind, LLC (HWF) (the "Entity")	NCR00210	01/01/2017	10/27/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from July 25, 2017, through August 30, 2017, Texas RE determined that the Entity, as a Generator Owner (GO), was in noncompliance with PRC-005-6 R1. Specifically, the Entity did not establish a Protection System Maintenance Program (PSMP) for the Entity's Sudden Pressure Relaying devices as required by PRC-005-6 R1. Prior to January 1, 2017, when PRC-005-6 R1 became enforceable, the Entity had a PSMP that identified a time-based maintenance method for the Entity's Protection System devices. However, although the Entity possessed four Fault Pressure Relays at the time, the Entity did not revise its PSMP on or before January 1, 2017, when PRC-005-6 R1 became enforceable. Instead, on October 27, 2017, the Entity established a PSMP that identified a time-based maintenance method for the Entity's Sudden Pressure Relaying devices, ending the noncompliance. The root cause of this issue is that the Entity did not have a sufficient process for compliance with PRC-005-6. The Entity stated that it did not devote sufficient resources and personnel to compliance activities regarding PRC-005-6. To address this root cause, the Entity revised its PSMP and devoted additional resources to its compliance program. This noncompliance started on January 1, 2017, when the Entity was required to adopt a PSMP that addresses the Entity's Sudden Pressure Relaying devices pursuant to the implementation plan for PRC-005-6, and ended on October 27, 2017, when the Entity established a PSMP that identified a time-based maintenance method for the Entity's Sudden Pressure Relaying devices.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, prior to the effective date of PRC-005-6 and prior to the start of the noncompliance, the Entity had already performed the maintenance activities required by PRC-00-5-6 Table 5 for the Sudden Pressure Relaying devices at issue, and no issues were identified. As a result, this issue relates only to a documentation issue regarding the Entity's PSMP, and does not involve a failure to perform maintenance activities on the Sudden Pressure Relaying devices. Second, the four Sudden Pressure Relaying devices represent only 6% of the 69 devices included in the Entity's PSMP. Third, the Entity's generating Facility is relatively small, comprising a single wind generator site with a nameplate rating of 185 MVA. Finally, no trips or Misoperations were identified as resulting from the issues identified during the Compliance Audit. No harm is known to have occurred. Texas RE considered the Entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the Entity: 1) established a PSMP that identified a time-based maintenance method for the Entity's Sudden Pressure Relaying devices; 2) conducted training for the Entity's employees, including an overview of applicable Reliability Standards; and 3) obtained additional personnel and consulting services to improve its compliance program. Texas RE verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018591	BAL-001-TRE-1	R6.3	Los Vientos Windpower V, LLC (LVWV)	NCR11603	12/01/2015	10/02/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted per an existing multi-region registered entity agreement from August 21, 2017, through October 27, 2017, Texas RE determined that LVWV, as a Generator Owner (GO), was in noncompliance with BAL-001-TRE-1 R6. Specifically, LVWV did not set its Governor parameters as required in Part 6.3. BAL-01-TRE-1 R6 states that for digital and electronic Governors, once frequency deviation has exceeded the Governor deadband from 60.000 Hz, the Governor setting shall follow the slope derived from the formula specified in the Requirements. The Compliance Audit team reviewed evidence of the slope formula for LVWV and determined that it indicated a change of power of 5% per 1 Hz instead of ~33% per 1 Hz as specified in the slope formula. The root cause of this noncompliance was an insufficient process to monitor primary frequency response (PFR) settings. The initial manufacturer SCADA settings had a straight 5% per 1Hz droop calculation, and the manufacture performed this calculation based on nameplate, which caused a calculation error within the droop parameter settings. LVWV lacked a process to monitor for settings changes or access control for permissions to make changes to PFR settings. The noncompliance started on December 1, 2015, the registration date for LVWV as a GO, and ended on October 2, 2017, the date LVWV corrected the droop slope formula.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, the single wind Facility operates at maximum output based on wind conditions at any given time and is therefore not expected to provide Primary Frequency Response (PFR) unless in a curtailed state. Second, the overall market frequency response in ERCOT is robust enough to ensure sufficient response is available to respond to Frequency Measurable Events. In particular, for the time period at issue, the ERCOT Interconnection Minimum Frequency Response was 381 and the average actual Interconnection Frequency Response was 876. No harm is known to have occurred. Texas RE considered LVWV’s compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, LVWV: 1) corrected the PFR settings to comply with the droop slope formula; 2) sent a communication to site managers and technicians, SCADA engineering personnel, control center operations, and internal leadership, requiring that any SCADA changes that impact PFR must be initiated through a Management of Change form and must be coordinated with the control center; 3) restricted user permissions for PFR settings changes to only SCADA and control center personnel; 4) implemented an automated quarterly review of PFR settings, including utilizing sending automated reminders to review the PFR settings and capture evidence; and 5) added PFR settings to its NERC Implementation Checklist which is utilized to gather NERC compliance evidence prior to the turnover from construction to operations for NERC sites. Texas RE verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018592	BAL-001-TRE-1	R6.3	Los Vientos Windpower IV, LLC (LVIV)	NCR11635	05/25/2016	10/02/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted per an existing multi-region registered entity agreement from August 21, 2017, through October 27, 2017, Texas RE determined that LVIV, as a Generator Owner (GO), was in noncompliance with BAL-001-TRE-1 R6. Specifically, LVIV did not set its Governor parameters as required in Part 6.3. BAL-01-TRE-1 R6 states that for digital and electronic Governors, once frequency deviation has exceeded the Governor deadband from 60.000 Hz, the Governor setting shall follow the slope derived from the formula specified in the Requirements. The Compliance Audit team reviewed evidence of the slope formula for LVIV and determined that it indicated a change of power of 5% per 1 Hz instead of ~33% per 1 Hz as specified in the slope formula. The root cause of this noncompliance was an insufficient process to monitor primary frequency response (PFR) settings. The initial manufacturer SCADA settings had a straight 5% per 1Hz droop calculation, and the manufacture performed this calculation based on nameplate, which caused a calculation error within the droop parameter settings. LVIV lacked a process to monitor for settings changes or access control for permissions to make changes to PFR settings. The noncompliance started on May 25, 2016, the registration date for LVIV as a GO, and ended on October 2, 2017, the date LVIV corrected the settings to comply with the droop slope formula.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, the single wind Facility operates at maximum output based on wind conditions at any given time and is therefore not expected to provide Primary Frequency Response (PFR) unless in a curtailed state. Second, the overall market frequency response in ERCOT is robust enough to ensure sufficient response is available to respond to Frequency Measurable Events. In particular, for the time period at issue, the ERCOT Interconnection Minimum Frequency Response was 402 and the average actual Interconnection Frequency Response was 901. No harm is known to have occurred. Texas RE considered LVIV's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, LVIV: 1) corrected the PFR settings to comply with the droop slope formula; 2) sent a communication to site managers and technicians, SCADA engineering personnel, control center operations, and internal leadership, requiring that any SCADA changes that impact PFR must be initiated through a Management of Change form and must be coordinated with the control center; 3) restricted user permissions for PFR settings changes to only SCADA and control center personnel; 4) implemented an automated quarterly review of PFR settings, including utilizing sending automated reminders to review the PFR settings and capture evidence; and 5) added PFR settings to its NERC Implementation Checklist which is utilized to gather NERC compliance evidence prior to the turnover from construction to operations for NERC sites. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018593	BAL-001-TRE-1	R6.3	Los Vientos Windpower III, LLC (LVWPIII)	NCR11538	04/21/2015	10/02/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted per an existing multi-region registered entity agreement from August 21, 2017, through October 27, 2017, Texas RE determined that LVWPIII, as a Generator Owner (GO), was in noncompliance with BAL-001-TRE-1 R6. Specifically, LVWPIII did not set its Governor parameters as required in Part 6.3. BAL-01-TRE-1 R6.3 states that for digital and electronic Governors, once frequency deviation has exceeded the Governor deadband from 60.000 Hz, the Governor setting shall follow the slope derived from the formula specified in the Requirement. The Compliance Audit team reviewed evidence of the droop slope formula for LVWPIII and determined that it indicated a change of power of 5% per 1 Hz instead of ~33% per 1 Hz as specified in the slope formula. The root cause of this noncompliance was an insufficient process to monitor primary frequency response (PFR) settings. The initial manufacturer SCADA settings had a straight 5% per 1Hz droop calculation, and the manufacture performed this calculation based on nameplate, which caused a calculation error within the droop parameter settings. LVWPIII lacked a process to monitor for settings changes or access control for permissions to make changes to PFR settings. The noncompliance started on April 21, 2015, the registration date for LVWPIII as a GO, and ended on October 2, 2017, the date LVWPIII corrected the settings to comply with the droop slope formula.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, the single wind Facility operates at maximum output based on wind conditions at any given time and is therefore not expected to provide Primary Frequency Response (PFR) unless in a curtailed state. Second, the overall market frequency response in ERCOT is robust enough to ensure sufficient response is available to respond to Frequency Measurable Events. In particular, for the time period at issue, the ERCOT Interconnection Minimum Frequency Response was 408 and the average actual Interconnection Frequency Response was 861. No harm is known to have occurred. Texas RE considered LVWPIII's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, LVWPIII: 1) corrected the PFR settings to comply with the droop slope formula; 2) sent a communication to site managers and technicians, SCADA engineering personnel, control center operations, and internal leadership, requiring that any SCADA changes that impact PFR must be initiated through a Management of Change form and must be coordinated with the control center; 3) restricted user permissions for PFR settings changes to only SCADA and control center personnel; 4) implemented an automated quarterly review of PFR settings, including utilizing sending automated reminders to review the PFR settings and capture evidence; and 5) added PFR settings to its NERC Implementation Checklist which is utilized to gather NERC compliance evidence prior to the turnover from construction to operations for NERC sites. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018594	BAL-001-TRE-1	R 6.1, 6.2, and 6.3	Los Vientos Windpower IB, LLC (LVWIB)	NCR11266	04/01/2015	08/31/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted per an existing multi-region registered entity agreement from August 21, 2017, through October 27, 2017, Texas RE determined that LVWIB, as a Generator Owner (GO), was in noncompliance with BAL-001-TRE-1 R6. Specifically, LVWIB did not set its Governor parameters as required by Parts 6.1, 6.2, and 6.3. During a review of primary frequency response (PFR) settings during the Compliance Audit, LVWIB discovered that it showed a disabled PFR status for recently implemented SCADA software. LVWIB immediately contacted the Electric Reliability Council of Texas (ERCOT) to inform them that the PFR was disabled and that a follow-up call would be provided once the settings were reviewed with the vendor and the PFR was enabled. LVWIB then worked with the SCADA vendor to troubleshoot, correct the settings, and enable the PFR. The root cause of this noncompliance was an insufficient process to monitor the primary frequency response settings. LVWIB determined that the primary frequency response setting was not re-enabled following the implementation of a new SCADA system in March of 2017. Therefore, LVWIB lacked a process to monitor its primary frequency response settings. This noncompliance started on April 1, 2015, the enforcement date of BAL-001-TRE pursuant to the Implementation Plan, and ended on August 31, 2017, when LVWIB re-enabled its PFR status.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, the single wind Facility operates at maximum output based on wind conditions at any given time and is, therefore, not expected to provide Primary Frequency Response (PFR) unless in a curtailed state. Second, the overall market frequency response in ERCOT is robust enough to ensure sufficient response is available to respond to Frequency Measurable Events. In particular, for the time period at issue, the ERCOT Interconnection Minimum Frequency Response (IMFR) was 410 and the average actual Interconnection Frequency response was 859. No harm is known to have occurred. Texas RE considered LVWIB's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, LVWIB: 1) enabled the PFR; 2) sent a communication to site managers and technicians, SCADA engineering personnel, control center operations, and internal leadership, to require that any SCADA changes that impact PFR must be initiated through a Management of Change form and must be coordinated with the control center; 3) restricted user permissions for PFR settings changes to only SCADA and control center personnel; 4) implemented an automated quarterly review of PFR settings, including utilizing sending automated reminders to review the PFR settings and capture evidence Texas RE has verified the completion of all mitigation activity; 5) implemented a change procedure for the collaboration between internal and external support groups for system updates that require settings review, testing, and ERCOT notifications; and 6) notified affected stakeholders of the new change procedure. Texas RE verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018595	BAL-001-TRE-1	R6.1	Los Vientos Windpower IA, LLC (LVWIA)	NCR11267	04/01/2015	07/20/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted per an existing multi-region registered entity agreement from August 21, 2017, through October 27, 2017, Texas RE determined that LVWIA, as a Generator Owner (GO), was in noncompliance with BAL-001-TRE-1 R6. Specifically, LVWIA did not set its Governor parameters as required in Part 6.1. During the Compliance Audit, LVWIA discovered that its Governor deadband was set at +/- 0.018Hz above the maximum +/- 0.017Hz required by BAL-001-TRE-1 R6.1. Upon discovery of the issue, LVWIA took immediate steps to investigate and correct the noncompliance within one week. The root cause of this noncompliance was an insufficient process to monitor its primary frequency response (PFR) settings. LVWIA believed that it was in compliance with the Requirement based upon passing results on an ERCOT primary frequency test utilizing the required droop and deadband settings as inputs for the test form. However, LVWIA lacked sufficient compliance procedures to monitor its PFR settings. This noncompliance started on April 1, 2015, the enforcement date of BAL-001-TRE-1 R6 pursuant to the Implementation Plan, and ended on July 20, 2017, when LVWIA revised its Governor deadband settings.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, the single wind Facility operates at maximum output based on wind conditions at any given time and is therefore not expected to provide Primary Frequency Response (PFR) unless in a curtailed state. Second, the overall market frequency response in ERCOT is robust enough to ensure sufficient response is available to respond to Frequency Measurable Events. In particular, for the time period at issue, the ERCOT Interconnection Minimum Frequency Response (IMFR) was 412 and the average actual Interconnection Frequency Response was 859. No harm is known to have occurred. Texas RE considered LVWIA's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, LVWIA: 1) corrected the Governor deadband at issue; 2) sent a communication to site managers and technicians, SCADA engineering personnel, control center operations, and internal leadership, to require that any SCADA changes that impact PFR must be initiated through a Management of Change form and must be coordinated with the control center; 3) restricted user permissions for PFR settings changes to only SCADA and control center personnel; and 4) implemented an automated quarterly review of PFR settings, including utilizing sending automated reminders to review the PFR settings and capture evidence. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017017700	VAR-002-4	R4	Luminant Energy Company, LLC (LUME) (the "Entity")	NCR10133	03/31/2017	04/03/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 6, 2017, the Entity submitted a Self-Report stating that, as a Generator Operator (GOP), it was in noncompliance with VAR-002-4 R4. Specifically, on March 31, 2017, the Entity did not timely notify its Transmission Operator (TOP) within 30 minutes of becoming aware of a change in reactive capability for the Oak Grove Steam Electric Station (OKG Station). On March 31, 2017, at 9:48 p.m., an animal intrusion caused the unavailability of a capacitor bank at the OKG Station. At the time, the Entity had alarms to notify personnel of a change in the availability of the capacitor bank at issue, but these alarms did not function as intended. The alarm failed to display a visual alert inside the OKG Station control room, and the alarm for the Entity's generation control system was misconfigured to indicate that the capacitor bank was available, rather than unavailable. At 9:49 p.m., the Entity became aware of the change in reactive capability. At that time, an operations specialist at another location received the alarm and contacted the OKG Station control room. However, the plant operator in the control room did not take further action because the OKG Station control room display did not indicate any issue. Subsequently, on April 3, 2017, the operations specialist contacted the OKG Station control room again, which prompted the Entity to identify that the capacitor bank was unavailable and to notify the Entity's TOP. The root cause of this issue is that the alarms set to alert plant operators regarding a change in the status of the capacitor bank at the OKG Station were not correctly configured. Because the alarms that were intended to alert plant operators did not function as intended, plant operators had decreased awareness regarding the status of the capacitor bank and therefore did not timely notify the Entity's TOP. The noncompliance began on March 31, 2017, at 10:20 p.m., which is 31 minutes after the Entity became aware of a change in reactive capability, and ended on April 3, 2017, at approximately 10:05 a.m., when the Entity notified its TOP of the change in reactive capability.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk posed by this issue is that the TOP would not have accurate information regarding the availability of reactive resources. In addition, the OKG Station is a relatively large Facility, comprising two 916.8 MW coal and lignite generating units. During the noncompliance, both units had average production of over 800 MW per hour and capacity factors of approximately 90%. However, the risk posed by this issue was reduced by the following factors. First, the duration of this issue was short, lasting less than four days. Second, during the time when the capacitor bank was unavailable, the TOP did not contact the Entity to request that the capacitor bank be connected to provide reactive capability. Finally, according to the Entity, the OKG Station could have and did provide immediate voltage support without the utilization of the capacitor bank. No harm is known to have occurred. Texas RE considered the Entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the Entity: 1) notified its TOP of the capacitor bank's status; 2) corrected the alarms for the capacitor banks at the OKG Station to function as intended; 3) modified the alarms for the capacitor banks at the OKG Station to also send an email alert to the Entity's compliance personnel; 4) distributed information to the Entity's personnel and conducted training regarding compliance obligations under VAR-002-4; and 5) revised its documented procedures regarding capacitor banks, autotransformers, and reactive resources to address the requirement to timely contact the TOP after a change in the status of a reactive capability. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018020516	BAL-001-TRE-1	R6.3	Mesquite Creek Wind LLC (MCW)	NCR11511	08/31/2015	05/18/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 9, 2018, MCW submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with BAL-001-TRE-1 R6. Specifically, MCW did not set its Governor parameters as required in Part 6.3. BAL-01-TRE-1 R6.3 states that for digital and electronic Governors, once frequency deviation has exceeded the Governor deadband from 60.000 Hz, the Governor setting shall follow the slope derived from the formula specified in the Requirement. During an extent of condition review related to an audit finding of other DERS facilities, Duke Energy Renewables (DERS) conducted a review of primary frequency response (PFR) settings at MCW and discovered that MCW had noncompliant Governor settings with the 5% droop slope formula specified in BAL-001-TRE-1 R6.3. The Governor settings indicated a 12.5% droop slope formula and MCW modified the settings on May 18, 2018, to be compliant with the required 5% droop slope formula, ending the noncompliance. The root cause of this noncompliance was an insufficient process to ensure compliance for acquisitions of NERC assets. DERS acquired MCW on August 31, 2015, and on December 17, 2015, DERS reviewed the deadband settings at MCW to confirm the frequency response deadband of +/- 0.017 pursuant to BAL-001-TRE-1 R6.1. MCW believed it was in compliance with BAL-001-TRE-1 R6 based upon passing results on an ERCOT PFR test utilizing the required droop and deadband settings as inputs for the test form. This noncompliance started on August 31, 2015, the date that DERS acquired MCW, and ended on May 18, 2018, when the settings for the slope droop formula at MCW were modified to be compliant with BAL-001-TRE-1 R6.3.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, the single wind Facility operates at maximum output based on wind conditions at any given time and is therefore not expected to provide Primary Frequency Response (PFR) unless in a curtailed state. Second, the overall market frequency response in ERCOT is robust enough to ensure sufficient response is available to respond to Frequency Measurable Events. In particular, for the time period at issue, the ERCOT Interconnection Minimum Frequency Response (IMFR) was 404 and the average actual Interconnection Frequency Response was 905. No harm is known to have occurred. Texas RE considered MCW's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, MCW: 1) revised the PFR settings to comply with the 5% droop slope formula; 2) implemented an automated quarterly review of PFR settings, including establishing recurring reminders in its compliance tool to send reminders to review and record the PFR settings; 3) implemented real time alarming in the control center for the PFR status; and 4) developed a due diligence process for evaluating NERC compliance for site acquisitions, including a NERC checklist for the previous owner or operator to provide evidence of compliance with PFR settings. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018588	BAL-001-TRE-1	R9	NRG Texas Power, LLC (NRGTP)	NCR10090	09/15/2017	11/06/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On November 3, 2017, NRG Texas Power, LLC (NRGTP) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with BAL-001-TRE-1 R9. Specifically, NRGTP did not meet the minimum 12-month rolling average initial Primary Frequency Response performance requirement of 0.75 at W. A. Parish unit 4 (WAP-4) based on participation in the previous eight Frequency Measurable Events (FMEs). In April of 2017, NRGTP began working to resolve frequency response issues and monitoring performance at WAP-4. On September 15, 2017, NRGTP discovered the noncompliance when WAP-4 had its 8th FME and its rolling average for initial Primary Frequency Response performance was 0.700, below the minimum required 0.75. WAP-4's performance remained below 0.75 until its 9th FME on November 6, 2017, when WAP-4's performance improved to 0.81. WAP-4's performance has continued to improve with a rolling average of 1.06 for its 10th FME on February 22, 2018, and 1.129 for its 11th FME on March 24, 2018. The root cause of this noncompliance was a failure by NRGTP staff to appropriately analyze and address various technical issues at WAP-4 in a timely fashion. As noted in its Self-Report, NRGTP began examining performance issues at WAP-4 in April of 2017, but did not engage a contractor to assist with analysis and identify the control system problems until August 2017. This noncompliance started on September 15, 2017, when WAP-4's initial Primary Frequency Response rolling average performance fell below 0.75, and ended on November 6, 2017, when WAP-4's performance reached 0.81.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. After becoming aware of the Primary Frequency Response issues at WAP-4, NRGTP voluntarily ceased assigning Responsive Reserve Service (RRS) to that Generator to minimize the potential for degradation in reliability in the event of a significant ERCOT disturbance. Further, WAP-4 has been compliant with BAL-001-TRE-1 R10, with a 12-month rolling average sustained Primary Frequency Response performance of 1.128, and there have been no issues with system wide Frequency Recovery in the ERCOT Region during the FMEs in scope. The overall market frequency response in ERCOT is robust enough to ensure sufficient frequency response is available to respond to the FMEs. In particular, for 2016 and 2017, the ERCOT Interconnection minimum Frequency Response (IMFR) was 381 and the average actual Interconnection Frequency Response over that period was 889. This noncompliance lasted for 52 days. No harm is known to have occurred. Texas RE considered NRGTP's and its affiliates' compliance history and determined there were no relevant instances of noncompliance.
Mitigation Activity (affidavit required)	To mitigate this noncompliance, NRGTP: 1) brought WAP-4 initial Primary Frequency Response performance into compliance with BAL-001-TRE-1 R9; 2) engaged a contractor to assist with analysis of MW oscillation and control system settings; 3) conducted mechanical repairs to the governor; and 4) identified and resolved inconsistencies in control system settings. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	**Entity Name**	**NCR ID**	**Noncompliance Start Date**	**Noncompliance End Date**	**Method of Discovery**	**Future Expected Mitigation Completion Date**
TRE2018020681	PRC-005-6	R3	Optim Energy Altura Cogen, LLC (Altura Cogen) (the "Entity")	NCR10072	04/01/2017	11/29/2018	Self-Certification	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On November 15, 2018, the Entity submitted a Self-Certification stating that, as a Generator Owner (GO), it was in noncompliance with PRC-005-6 R3. Specifically, the Entity did not have evidence that it had completed four of the six maintenance activities with 18-month maximum maintenance intervals for 16 vented lead acid (VLA) batteries pursuant to PRC-005-6 Table 1-4(a). By November 29, 2018, the Entity ended the noncompliance by performing and documenting the required maintenance activities for the VLA batteries at issue that remained in service. The root cause of this issue is that the Entity did not have a sufficient process for compliance with PRC-005-6 R3. Specifically, the forms used by the Entity did not clearly record that the Entity had verified the battery terminal connection resistance, verified the battery intercell or unit-to-unit connection resistance, inspected the cell condition of all individual battery cells, and verified the physical condition of the battery rack. In addition, the Entity did not possess the equipment necessary to verify the battery terminal connection resistance or verify the battery intercell or unit-to-unit connection resistance, and, instead, had performed other maintenance activities that the Entity had believed would satisfy PRC-005-6 R3. The noncompliance started on April 1, 2017, when maintenance activities with 18-month maximum maintenance intervals were required to be performed and documented, and ended on November 29, 2018, when the Entity performed and documented the required maintenance activities for the VLA batteries at issue that remained in service.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the bulk power system based on the following factors. The risk posed by this issue is that the Entity would not know whether its Protection System devices would function as intended. In addition, the Entity operates a relatively large combined cycle Facility, comprising six gas turbines, and one steam turbine with a total rating of 712.1 MVA. However, the risk posed by this issue was reduced by the following factors. First, the 16 VLA battery devices at issue represent only approximately 6.4% of the total of 251 Protection System devices in the Entity's Protection System Maintenance Program. Second, the Entity did not identify any cells that had failed when it performed the required maintenance activities with 18-month maximum maintenance intervals. Third, the Entity had been performing regular testing on the VLA batteries at issue, including checking battery voltage and the specific gravity of each cell, reducing the likelihood that the Entity would be unaware of a degradation in the performance of the devices at issue. No harm is known to have occurred. Texas RE considered the Entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the Entity: 1) performed the maintenance activities for the in-service VLA batteries at issue; 2) obtained equipment to test battery resistance so that future maintenance activities can be performed by the Entity's internal personnel; 3) created new forms for logging the completion of the maintenance activities at issue; 4) trained its personnel regarding the requirements of PRC-005-6 Table 1-4(a); and 5) revised the task in the Entity's plant maintenance management software to include more detailed periodicity, due dates, and responsible personnel for the maintenance activities described in PRC-005-6 Table 1-4(a).

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018018923	PRC-019-2	R1	Port Comfort Power LLC (PortComfortPower)	NCR11765	07/24/2017	01/05/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 29, 2017, Port Comfort Power submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with PRC-019-2. Specifically, PortComfortPower failed to coordinate the voltage regulating system controls with the applicable equipment capabilities and settings of the applicable Protection System Devices and functions. PortComfortPower initially registered with NERC on July 24, 2017, without evidence that it had coordinated its voltage regulating system controls with the applicable equipment capabilities and settings of the applicable Protection System Devices and functions, in accordance with PRC-019-2 R1. PortComfortPower conducted a review of its compliance obligations, and on December 8, 2017, the noncompliance was discovered. On January 5, 2018, PortComfortPower performed the required PRC-019-2 coordination study. The root cause for this noncompliance was that PortComfortPower did not assign sufficient resources and adequately prepare for full compliance with the NERC Standards. This noncompliance began on July 24, 2017, when PortComfortPower was initially registered with NERC without evidence that it had coordinated its voltage regulating system controls with the applicable equipment capabilities and settings of the applicable Protection System Devices and functions, in accordance with PRC-019-2 R1. The noncompliance ended on January 5, 2018, when PortComfortPower performed a PRC-019-2 coordination study.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, PortComfortPower lacked the evidence required by the standard to show that it had coordinated its applicable equipment capabilities and settings of the applicable Protection System Devices and functions. However, it was determined during the coordination study that no actual settings changes were necessary for compliance with PRC-019-2. Additionally, PortComfortPower did not trip off-line during the period of the noncompliance; the Facility reached full compliance within 28 days of discovering the noncompliance; and the noncompliance lasted less than 5 months and 12 days. No harm is known to have occurred. Texas RE considered PortComfortPower's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, PortComfortPower: 1) completed the required coordination study within 28 days of discovering the noncompliance thereby limiting the noncompliance to 5 months and 12 days; 2) effectuated a plant procedures to implement PRC-019-2; and 3) created automatic reminders to annually review the PRC-019-2 procedure and update it as necessary, and to notify PortComfortPower personnel one year prior to the next PRC-019-2 deadline. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018018924	PRC-024-2	R1	Port Comfort Power LLC (PortComfortPower)	NCR11765	07/24/2017	03/27/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 29, 2017, PortComfortPower submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with PRC-024-2. Specifically, it failed to set its frequency protective relaying such that it would not trip the generating units within the "no trip zone" of PRC-024 Attachment 1, in accordance with PRC-024-2 R1. PortComfortPower initially registered with NERC on July 24, 2017, with generator frequency protective relaying activated to trip its applicable generating units within the "no trip zone" of PRC-024-2 Attachment 1. PortComfortPower conducted a review of its compliance obligations, and on December 8, 2017, the noncompliance was discovered. On March 27, 2018, PortComfortPower completed the required settings upgrades ending PortComfortPower's noncompliance with PRC-024-2 R1. The root cause for this noncompliance was that PortComfortPower did not assign sufficient resources and adequately prepare for full compliance with the NERC Standards. This noncompliance began on July 24, 2017, when PortComfortPower was initially registered with NERC with its generator frequency protective relaying activated to trip its applicable generating units within the "no trip zone." The noncompliance ended on March 27, 2018, when PortComfortPower performed the necessary settings upgrades such that the generator's frequency protective relaying would no longer trip within the "no trip zone."
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk posed by this instance of noncompliance is the tripping of a generating unit within a "no trip zone." Several factors mitigated the risk posed by this issue. First, PortComfortPower has a relatively small power output. Its nameplate rating is 121 MW; the GO reported that its actual total power output capability is approximately 100MW; and its capacity factor is 4.41%. Second, when PortComfortPower operated during the period of noncompliance no trips occurred due to the applicable relay trip settings being within the "no trip zone." No harm is known to have occurred. Texas RE considered PortComfortPower's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, PortComfortPower: 1) completed the required settings upgrades limiting the period of noncompliance to 8 months, 3 days; 2) created a plant procedure to ensure that generator protective relay settings are reviewed and set such that generating units remain connected during defined frequency excursions; and 3) created annual automatic reminders requiring specific PortComfortPower staff to review generator protective relay settings. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018020683	COM-001-2	R4	Sharyland Utilities, L.L.C. (SU) (the "Entity")	NCR04119	10/01/2015	02/06/2019	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from September 4, 2018, through September 14, 2018, Texas RE determined that the Entity, as a Transmission Operator (TOP), was in noncompliance with COM-001-2 R4. Specifically, the Entity failed to designate an Alternative Interpersonal Communication (AIC) capability with the required entities. The Entity had a documented operations plan that stated that if there were a failure of the primary telephone system, then satellite phones would be used for critical communications. However, the Compliance Audit team determined that this general description was not sufficient to meet the requirement to designate an AIC. Additionally, the Compliance Audit team determined that the Entity did not communicate the designation of its AIC to the entities specified in COM-001-2 R4. The root cause of this noncompliance was a misunderstanding of the Standard. The Entity had a documented operation plan that addressed use of the satellite phone as a backup method of communication if there is a failure of the primary telephone system, and the Entity believed this was sufficient to demonstrate compliance with the Standard. Additionally, the Entity did not have documentation to demonstrate that it communicated the designation of the AIC to the required entities. This noncompliance started on October 1, 2015, when the Standard was mandatory and enforceable, and ended on February 6, 2019, when the Entity revised its documented operation plan process to designate its AIC capability.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, during the Compliance Audit, the Entity demonstrated that it addressed the use of its satellite phone as a back-up method for critical communications in its operations plan; therefore, operators were aware of the satellite phones even if they were not formally designated as AICs. Second, during the Compliance Audit the Entity demonstrated that it has Interpersonal Communication capability with its Reliability Coordinator, Balancing Authority, and the Distribution Provider within its Transmission Operator Area, and each adjacent Transmission Operator synchronously connected. The Entity noted that at no point during the Compliance Audit period was it asynchronously connected with any TOPs. No harm is known to have occurred. Texas RE considered the Entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation Activity (affidavit required)	To mitigate this noncompliance, the Entity: 1) notified the entities specified in COM-001-3 R4 of its designated AIC capability; 2) revised its documented operation plan to designate its satellite phone as its AIC capability; and 3) executed an operations agreement with another registered entity to perform TOP operations and, as a result, will no longer perform the TOP function. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018020684	PRC-001-1.1(ii)	R3.2	Sharyland Utilities, L.L.C. (SU) (the "Entity")	NCR04119	06/14/2017	04/26/2018	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from September 4, 2018, through September 14, 2018, Texas RE determined that the Entity, as a Transmission Operator (TOP), was in noncompliance with PRC-001-1.1(ii) R3.2. Specifically, the Entity failed to coordinate two protective system changes with neighboring TOPs. During a Compliance Audit, it was discovered that in two separate instances the Entity failed to coordinate protective system changes with neighboring TOPs. Both instances addressed permissive overreaching transfer trip (POTT) setting changes that were made as part of a Corrective Action Plan for a Misoperation at one substation. The first instance occurred on June 14, 2017, when the Entity made POTT setting changes on protective relays for two 345-kV transmission lines. However, the Entity did not coordinate with the neighboring TOP until April 26, 2018, when the Entity sent the relevant relay changes to the neighboring TOP. The second instance occurred on October 12, 2017, when the Entity made POTT setting changes on protective relays for two 345-kV transmission lines. However, the Entity did not coordinate with the neighboring TOP until December 13, 2017. The root cause of this noncompliance was an insufficient process to comply with PRC-001-1.1(ii) R3. The Entity's System Protection coordination procedure did not address Protection System changes that result from a Corrective Action Plan. Consequently, the insufficient process led to the Entity's failure to coordinate the relay setting changes with neighboring TOPs for the two instances. This noncompliance started on June 14, 2017, when the Entity made relay setting changes that were required to be coordinated with the neighboring TOP and ended on April 26, 2018, when the Entity completed the required coordination with the neighboring TOPs.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, the Entity implemented standard setting changes on the impacted line relays to enhance the POTT scheme and ensure it is sensitive enough to correctly detect faults in the reverse and forward direction. The Misoperation that led to the Corrective Action Plan and settings changes identified a system protection issue in which there was a lack of sensitivity that led to mis-identifying the fault as a forward fault rather than a reverse fault. In the geographic area where this occurred, the magnitude of the fault current is low and, in some cases, the distance element for Zone 2 and Zone 3 was not able to detect reverse or forward faults due to a weak infeed. Second, the two neighboring TOPs were relatively small, responsible for operating a total of 872 MW and 1,253 MW. No harm is known to have occurred. Texas RE considered the Entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation Activity	To mitigate this noncompliance, the Entity: 1) coordinated with the neighboring TOPs on the changes to the relay settings at issue in the two instances; and 2) executed an operations agreement with another registered entity to perform TOP operations and, as a result, will no longer perform the TOP function. Texas RE has verified completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018020687	COM-002-4	R2	Sharyland Utilities, L.L.C. (SU) (the "Entity")	NCR04119	07/07/2016	02/11/2019	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from September 4, 2018, through September 14, 2018, Texas RE determined that the Entity, as a Transmission Operator (TOP), was in noncompliance with COM-002-4 R2. Specifically, the Entity failed to conduct initial training for each of its operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System on the documented communications protocols developed in COM-002-4 R1 prior to individual operators issuing an Operating Instruction. During the Compliance Audit, two instances of noncompliance were discovered. First, the Entity's training materials for compliance with COM-002-4 R2 addressed the documented communications protocols developed in COM-002-4 R1. However, the training recited verbatim Parts 1.5 (specify instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification) and 1.6 (specify the nomenclature for Transmission interface Elements and Transmission interface Facilities when issuing an oral or written Operating Instruction) but did not address the Entity's communications protocols. The Entity revised its training materials on September 18, 2018 to address its specific communications protocols, and provided the revised training to all Transmission Operators by February 11, 2019, ending this instance of noncompliance. Second, the Entity failed to complete the training for one Transmission Operator prior to his first issuance of an Operating Instruction following the enforcement date for COM-002-4 R2. The Entity completed and documented the training for this Transmission Operator on February 16, 2017, ending this instance of noncompliance. The root cause of the first instance of noncompliance was insufficient training materials for compliance with COM-002-4 R2. The root cause of the second instance of noncompliance was the Entity believed that the Transmission Operator completed the required training on January 11, 2016, along with one other Transmission Operator, but could not locate documentation to demonstrate the training was completed for the Transmission Operator at issue. This noncompliance started on July 7, 2016, when the Transmission Operator issued his first Operating Instruction after COM-002-4 R2 became enforceable and prior to completing the required training, and ended on February 11, 2019, when the Entity conducted its revised and fully compliant training for COM-002-4 R2 to its Transmission Operators.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, the Entity timely provided and documented initial training to the vast majority of its Transmission Operators; however, the training was insufficient to address COM-002-4 R1.5 and 1.6. Second, during the Compliance Audit, the Compliance Audit team listened to the Operating Instructions submitted by the Entity for compliance with COM-002-4 R4, and reviewed the Entity's assessments of Operating Instructions which all notes positive feedback. No harm is known to have occurred. Texas RE considered the Entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation Activity (affidavit required)	To mitigate this noncompliance, the Entity: 1) completed and documented the required training for the one Transmission Operator at issue; 2) updated training materials to: specify the instances that require time identification when issuing an oral or written Operating Instruction and the format for the time identification; and specify the nomenclature for Transmission interface Elements and Transmission interface Facilities when issuing an oral or written Operating Instruction; 3) provided the revised training to Transmission Operators; and 4) executed an operations agreement with another registered entity to perform TOP operations and, as a result, will no longer perform the TOP function . Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018020688	COM-002-4	R1.5	Sharyland Utilities, L.L.C. (SU) (the "Entity")	NCR04119	07/01/2016	09/18/2018	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from September 4, 2018, through September 14, 2018, Texas RE determined that the Entity, as a Transmission Operator (TOP), was in noncompliance with COM-002-4 R1. Specifically, the Entity failed to specify the instances that require time identification when issuing an oral or written Operating Instruction and the format for the time identification. The entity had a documented process for compliance with COM-002-4 R1 that required operators, when issuing or receiving Operating Instructions, to log the instruction issued or received in the daily log and time stamp it accordingly. However, the written process failed to specify the instances that require time identification when issuing an oral or written Operating Instruction and the format for the time identification. The root cause for this noncompliance was an insufficient documented process for compliance with COM-002-4 R1.5. This noncompliance started on July 1, 2016, when the Standard became mandatory and enforceable, and ended on September 18, 2018, when the Entity revised its documented procedure to specify the instances that require time identification when issuing an oral or written Operating Instruction and specified the format for time identification.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, the Compliance Audit team determined that the Entity's documented process addressed COM-002-4 R1.1, 1.2, 1.3, 1.4, and 1.6; therefore, the noncompliance was limited to part 1.5. Second, although the documented process was insufficient for compliance with Part 1.5, the documented process directed operators, when issuing or receiving Operating Instructions, to log the instruction issued or received in the daily log and time stamp it accordingly. Third, during the Compliance Audit, the Compliance Audit team listened to the Operating Instructions submitted by the Entity for compliance with COM-002-4 R4, and reviewed the Entity's assessments of Operating Instructions which all notes positive feedback. No harm is known to have occurred. Texas RE considered the Entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation Activity (affidavit required)	To mitigate this noncompliance, the Entity: 1) revised its documented procedure to require time identification when issuing an oral or written Operating Instruction and the format for the time identification; 2) provided training to the Transmission Operators of the revised documented procedure; and 3) executed an operations agreement with another registered entity to perform TOP operations and, as a result, will no longer perform the TOP function. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018019001	PRC-005-6	R3	Sherbino I Wind Farm, LLC (SWF)	NCR10261	01/01/2018	01/24/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 18, 2018, SWF submitted a Self-Report to Texas RE after receiving notice of an upcoming Compliance Audit stating that, as a Generator Owner (GO), it was in noncompliance with PRC-005-6 R3. Specifically, SWF did not timely perform the required maintenance activities with six-month intervals for one Valve Regulated Lead Acid (VRLA) battery bank. SWF identified this issue during an internal review of the testing records for its VRLA battery bank. On June 12, 2017, SWF timely performed maintenance activities with a six-month maximum interval on its single VRLA battery bank. Accordingly, the next interval for these maintenance activities was due on December 31, 2017, which is the last day of the sixth calendar month following June 2017. However, SWF did not perform the required maintenance activities until January 24, 2018, which is 24 days after the date when the maintenance activities were due. The root cause of the noncompliance is that SWF did not have a sufficient process to ensure that the deadlines for maintenance activities were accurately recorded in SWF's compliance task management software. Specifically, according to SWF's compliance task management software, the maintenance activities performed on June 12, 2017, were not due until over one month later, on July 31, 2017. After these maintenance activities were completed, a task was created in the compliance task management software for the next interval. However, rather than setting the due date for the next interval within six calendar months of when the activities were last performed, the due date recorded in the compliance task manager was six calendar months from July 2017, when the previous task was due. As a result, the compliance task management software incorrectly showed that these maintenance activities were due by January 31, 2018, when, actually, these maintenance activities were due by December 31, 2017. The noncompliance started on January 1, 2018, which is the day after the required maintenance activities were due to be performed, and ended on January 24, 2018, when the required maintenance activities were performed.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. This risk posed by this issue is that the VRLA battery bank at issue would not function as intended. However, the risk posed by this issue is reduced by several factors. First, the single VRLA battery bank at issue comprises only 3% of SWF's 30 Protection System devices. Second, SWF did not identify any issues with the VRLA battery bank when it performed the required maintenance activities. Third, the duration of this issue was short, lasting 24 days. No harm is known to have occurred. Texas RE considered SWF's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, SWF: 1) performed the required maintenance activity for the VRLA battery bank at issue; 2) modified a task in SWF's compliance task management software to prompt SWF compliance personnel verify that correct due dates have been recorded for the next maintenance interval; 3) modified a task in SWF's compliance task management software to prompt personnel performing the maintenance activities to verify that the correct due date has been recorded for the next interval; 4) updated the weekly summary report created by SWF personnel to include a summary of Protection System maintenance activities; 5) conducted a review of prior maintenance activities to confirm that no other delays have occurred and verify that all pertinent tasks in the compliance task management software have the correct next due date; 6) sent an email to SWF personnel summarizing SWF's Protection System maintenance activities; and 7) conducted training regarding the use of SWF's compliance task management software for tracking Protection System maintenance activities. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018019802	PRC-024-2	R1	Sherbino I Wind Farm, LLC (SWF)	NCR10261	07/01/2016	06/19/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from March 26, 2018, through March 30, 2018, Texas RE determined that SWF, as a Generator Owner (GO), was in noncompliance with PRC-024-2 R1. Specifically, SWF did not timely set its generator frequency relaying such that the generator frequency protective relaying does not trip the applicable generating unit within the "no trip zone." SWF owns a single-site 150 MW wind generation Facility that has generator frequency and voltage protective relaying. When PRC-024-2 R1 became enforceable, SWF's protective relays were set with compliant underfrequency settings but did not have compliant overfrequency settings. Pursuant to the implementation plan for PRC-024-2 R1, a single-site wind Facility's generator frequency protective relay settings must be compliant with the "no trip zone" by July 1, 2016. However, SWF did not complete the required settings changes until June 19, 2017, approximately 11 months later. The root cause of this noncompliance was a misunderstanding of the required date for SWF to set the generator frequency protective relaying settings outside the "no trip zone" for its wind generation Facility. In particular, SWF mistakenly believed that it was only required to obtain compliance for 40% of its turbines and protective relays prior to July 1, 2016, and 60% of its turbines and protective relays prior to July 1, 2017. Accordingly, by May 25, 2016, SWF became compliant regarding its 50 turbines by timely documenting an equipment limitation and communicating the limitation to SWF's Planning Coordinator and Transmission Planner. However, SWF did not become compliant regarding the protective relays associated with SWF's collector system and generation interconnection transmission line until June 19, 2017. The noncompliance started on July 1, 2016, when PRC-024-2 R1 became enforceable, and ended on June 19, 2017, when SWF changed the settings for its protective relays.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk posed by this instance of noncompliance is the tripping of a generating unit within a "no trip zone." However, the risk posed by this issue is reduced by several factors. First, SWF produced a relatively small amount of power, producing a capacity factor of 27% during the noncompliance. Second, the single wind generation Facility at issue has never experienced a unit trip due to the applicable relay trip settings being set within the "no trip zone." Further, although SWF's protective relays did now have correct overfrequency settings, SWF's Transmission Coordinator and Transmission Planner had already been notified that SWF's turbines could experience a trip inside the "no trip zone" during high frequency situations. No harm is known to have occurred. Texas RE considered SWF's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, SWF: 1) implemented protective relay settings that are compliant with PRC-024-2 R1; 2) created a task in SWF's compliance task management software for SWF personnel to annually verify compliance with PRC-024-2; and 3) implemented a spreadsheet to track meetings regularly conducted with SWF compliance personnel and engineers to continuously review SWF's compliance with PRC-024-2, including discussing software updates to SWF's turbines to address SWF's documented equipment limitations. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018019803	PRC-024-2	R2	Sherbino I Wind Farm, LLC (SWF)	NCR10261	07/01/2016	06/19/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from March 26, 2018, through March 30, 2018, Texas RE determined that SWF, as a Generator Owner (GO), was in noncompliance with PRC-024-2 R2. Specifically, SWF did not timely set its generator voltage relaying such that the generator frequency protective relaying does not trip the applicable generating unit within the "no trip zone." SWF owns a single-site 150 MW wind generation Facility that has generator frequency and voltage protective relaying. When PRC-024-2 R2 became enforceable, SWF's protective relays did not have compliant undervoltage and overvoltage settings. Pursuant to the implementation plan for PRC-024-2 R2, a single-site wind Facility's generator voltage protective relay settings must be compliant with the "no trip zone" by July 1, 2016. However, SWF did not complete the required settings changes until June 19, 2017, approximately 11 months later. The root cause of this noncompliance was a misunderstanding of the required date for SWF to set the generator voltage protective relaying settings outside the "no trip zone" for its wind generation Facility. In particular, SWF mistakenly believed that it was only required to obtain compliance for 40% of its turbines and protective relays prior to July 1, 2016, and 60% of its turbines and protective relays prior to July 1, 2017. Accordingly, by May 25, 2016, SWF became compliant regarding its 50 turbines by timely documenting an equipment limitation and communicating the limitation to SWF's Planning Coordinator and Transmission Planner. However, SWF did not become compliant regarding the protective relays associated with SWF's collector system and generation interconnection transmission line until June 19, 2017. The noncompliance started on July 1, 2016, when PRC-024-2 R2 became enforceable, and ended on June 19, 2017, when SWF changed the settings for its protective relays.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk posed by this instance of noncompliance is the tripping of a generating unit within a "no trip zone." However, the risk posed by this issue is reduced by several factors. First, SWF produced a relatively small amount of power, producing a capacity factor of 27% during the noncompliance. Second, the single wind generation Facility at issue has never experienced a unit trip due to the applicable relay trip settings being set within the "no trip zone." No harm is known to have occurred. Texas RE considered SWF's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, SWF: 1) implemented protective relay settings that are compliant with PRC-024-2 R2; 2) created a task in SWF's compliance task management software for SWF personnel to annually verify compliance with PRC-024-2; and 3) implemented a spreadsheet to track meetings regularly conducted with SWF compliance personnel and engineers to continuously review SWF's compliance with PRC-024-2, including discussing software updates to SWF's turbines to address SWF's documented equipment limitations. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018389	PRC-019-2	R1	Texas Medical Center Central Heating and Cooling Services Corp (TECO)	NCR11116	07/01/2016	01/03/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 27, 2017, Texas Medical Center Central Heating and Cooling Services Corp (TECO) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with PRC-019-2. Specifically, TECO did not verify the coordination of its voltage regulating system controls with the equipment capabilities and settings of applicable Protection System devices and functions for its Facility by July 1, 2016 as required. TECO engaged a third-party contractor to supervise its compliance with NERC Standards. The contractor reviewed TECO's compliance records and discovered that TECO failed to verify the coordination of its voltage controls and generation protection devices in accordance with PRC-019-2 R1 by the July 1, 2016 deadline for its generation Facility. TECO's contractor arranged for the performance of the required coordination study. The requisite study was completed on January 3, 2018, ending the noncompliance. The root cause of this noncompliance was a misunderstanding of the required date for TECO to complete the coordination specified in PRC-019-2. In particular, TECO failed to recognize the correct effective date for the standard as it applied to TECO's single unit. TECO incorrectly assumed that facilities with a single generator had five calendar years following board of Trustees approval to comply with this standard. This noncompliance started on July 1, 2016, when PRC-019-2 R1 became mandatory and enforceable, and ended on January 3, 2018, when TECO verified the coordination of its voltage regulating system controls with the equipment capabilities and settings of applicable Protection System devices and functions for its Facility.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The average output for this Facility is small (48 MW), which represents 0.062% of ERCOT's available capacity. Additionally, approximately 70% of the MWh generated are consumed within the Private Use Network (PUN). No harm is known to have occurred. Texas RE considered TECO's compliance history and determined there were no relevant instances of noncompliance.
Mitigation Activity	To mitigate this noncompliance, TECO: 1) completed the requisite Real Power capability verifications for its generating unit, and provided the results of those verifications to its TP; 2) engaged a third-party contractor to supervise NERC compliance activity; 3) revised its PRC-019-2 procedure to reflect the appropriate periodic verification due dates; and 4) implemented tracking spreadsheet to remind staff of periodic compliance deadlines. Texas RE verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018390	MOD-025-2	R1	Texas Medical Center Central Heating and Cooling Services Corp (TECO)	NCR11116	07/01/2016	02/20/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 27, 2017, Texas Medical Center Central Heating and Cooling Services Corp (TECO) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with MOD-025-2 R1. Specifically, TECO did not verify the Real Power capability of its applicable generating unit in accordance with MOD-025-2, Attachment 1, by July 1, 2016, or provide the results of those verifications to its Transmission Planner (TP) as required. TECO engaged a third-party contractor to supervise its compliance with NERC Standards. Upon review of TECO's compliance records, TECO's contractor discovered that TECO failed to verify its Real Power capability, or to provide the results of those verifications to its TP as required. TECO's contractor arranged for the performance of the required verifications. The required verifications were completed on January 3, 2018, and the results were provided to the TP on February 20, 2018, ending the noncompliance. The root cause of this noncompliance was a misunderstanding of the required date for TECO to complete the Real Power verifications specified in MOD-025-2. In particular, TECO failed to recognize the correct effective date for the standard as it applied to TECO's single unit. TECO incorrectly assumed that facilities with a single Generator had five calendar years following board of Trustees approval to comply with this standard. This noncompliance started on July 1, 2016, when MOD-025-2 became mandatory and enforceable, and ended on February 20, 2018, when TECO provided the results of its Real Power verifications to its TP as required.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The average output for this Facility is small (48 MW), which represents 0.062% of ERCOT's available capacity. Additionally, approximately 70% of the MWh generated are consumed within the Private Use Network (PUN). No harm is known to have occurred. Texas RE considered TECO's compliance history and determined there were no relevant instances of noncompliance.
Mitigation Activity	To mitigate this noncompliance, TECO: 1) completed the required verifications, and provided the results to the TP; 2) engaged a third-party contractor to supervise NERC compliance activity; 3) revised its MOD-025-2 procedure to reflect the appropriate periodic verification due dates; and 4) implemented tracking spreadsheet to remind staff of periodic compliance deadlines. Texas RE verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018391	MOD-025-2	R2	Texas Medical Center Central Heating and Cooling Services Corp (TECO)	NCR11116	07/01/2016	02/20/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 27, 2017, Texas Medical Center Central Heating and Cooling Services Corp (TECO) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with MOD-025-2 R2. Specifically, TECO did not verify the Reactive Power capability of its applicable generating unit in accordance with MOD-025-2, Attachment 1, by July 1, 2016, or provide the results of those verifications to its Transmission Planner (TP) as required. TECO engaged a third-party contractor to supervise its compliance with NERC Standards. Upon review of TECO's compliance records, TECO's contractor discovered that TECO failed to verify its Reactive Power capability, or to provide the results of those verifications to its TP as required. TECO's contractor arranged for the performance of the required verifications. The required verifications were completed on January 3, 2018, and the results were provided to the TP on February 20, 2018, ending the noncompliance. The root cause of this noncompliance was a misunderstanding of the required date for TECO to complete the Reactive Power verifications specified in MOD-025-2. In particular, TECO failed to recognize the correct effective date for the standard as it applied to TECO's single unit. TECO incorrectly assumed that facilities with a single Generator had five calendar years following board of Trustees approval to comply with this standard. This noncompliance started on July 1, 2016, when MOD-025-2 became mandatory and enforceable, and ended on February 20, 2018, when TECO provided the results its Reactive Power verifications to its TP as required.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The average output for this Facility is small (48 MW), which represents 0.062% of ERCOT's available capacity. Additionally, approximately 70% of the MWh generated are consumed within the Private Use Network (PUN). No harm is known to have occurred. Texas RE considered TECO's compliance history and determined there were no relevant instances of noncompliance.
Mitigation Activity	To mitigate this noncompliance, TECO: 1) completed the required verifications, and provided the results to the TP; 2) engaged a third-party contractor to supervise NERC compliance activity; 3) revised its MOD-025-2 procedure to reflect the appropriate periodic verification due dates; and 4) implemented tracking spreadsheet to remind staff of periodic compliance deadlines. Texas RE verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019931	EOP-004-3	R2	Aragonne Wind LLC	NCR05014	03/27/2018	06/13/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On June 21, 2018 the entity submitted a Self-Report stating that, as a Generator Operator (GOP), it was in noncompliance with EOP-004-3 R2. Specifically, on March 25, 2018 at 2:26 AM the entity's wind turbine faulted. On that same day the entity's plant manager was notified at 9:53 AM that six conductors had been cut by trespassers from the wind turbine. On June 13, 2018 the entity notified NERC of the wind turbine fault, 79 days after the required reporting date of March 27, 2018. After reviewing all relevant information, WECC determined the entity failed to report events per their Operating plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend, as required by EOP-004-3 R2. The root cause of the issue was the entity's lack of awareness regarding individual employee responsibilities to notify in a timely manner the correct parties and to report the wind turbine event. This issue began on March 27, 2018 when the entity failed to report the wind turbine fault per its Operating Plan and ended on June 13, 2018, when the entity notified NERC of the wind turbine fault, for a total of 79 days.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to report events per their Operating plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend, as required by EOP-004-3 R2. However, as compensation, the size of the generator at issue is a 36 MW wind intermittent generation resource, the potential impact of which on the reliability of the BPS would have been negligible and limited to wind generation site at the time of the event. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	The entity completed mitigating activities and WECC verified the entity's mitigating activities. To remediate and mitigate this issue, the entity has: a. notified NERC and WECC of the wind turbine fault through an EOP-004 Attachment 2 Event Reporting form; b. generated awareness of the EOP-004 Standard to its internal personnel by: • sending an email to all plant managers reviewing the EOP-004 requirements, and reporting requirements including applicability to individual wind turbine generators as BES elements; • distributing a slide deck from an earlier training session in that reviews the EOP-004 procedures and Standard; • discussing the event with the personnel related the instant issue; and • conducting a leadership meeting to discuss the instant issue with the plant managers, technicians, engineering, and control center manager and support staff.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017391	BAL-005-0.2b	R11	Bonneville Power Administration	NCR05032	9/13/2012	3/24/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On April 13, 2017, the entity submitted a Self-Report stating, as a Balancing Authority (BA), it had a potential noncompliance with BAL-005-0.2b R11. Specifically, the entity reported that it did not include the effect of ramp rates in its Scheduled Interchanges values to calculate Area Control Error (ACE). Specifically, when non-standard ramp rates were generated by the E-tag software, personnel at the entity entered the rates into the ACE equation and all transactions and modifications were implemented using a non-standard ramp rate. The root cause of the issue was the entity's E-tag software was incorrectly validating the ramp rates of Interchange Schedules which caused non-standard ramp rates to be approved by personnel who were not aware of the impact of inaccurate ramp rates in the Scheduled Interchange values for the ACE equation. The entity coordinates Scheduled Interchange transactions with several other BAs. Following a year-long investigation, most of the instances of incorrectly calculated ramp rates originated from a single entity. This issue began on September 13, 2012, when the Standard became mandatory and enforceable and ended on March 24, 2018 when the entity completed the new E-tag software to correctly validate the ramp rate, for a total of 2019 days of noncompliance. After reviewing all relevant information, WECC Enforcement determined the entity failed to effectively perform BAL-005-0.2b R11.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE, as required by BAL-005-0.2b R11. The entity did not implement any detective or preventative controls. However, as compensation, the entity had several thousand MW of generation within its BA footprint and a deviation created during the ramp period would be a very small portion of the overall ACE. The duration of any deviations would only be a few MW per minute, over the ramp duration of 20 minutes. Unscheduled flow would flow one direction for half of the ramp period and the other direction for the other half. Once the ramp period expired, the interchange would again be balanced. Overall, the number of the non-standard ramp rate submissions were less than 1% of the overall E-tag volume during the period of noncompliance. At the end of each ramp period, the Scheduled Interchange would correct itself again, eliminating extended risk to the BPS. No harm is known to have occurred. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, WECC: 1) worked with E-tag software vendor to fix the software so the ramp rates will be validated; 2) tested the new validation software updates provided by the E-tag software vendor; 3) trained scheduling personnel about the new validation software and trained them how the new validation software will deny E-tags with non-standard ramp rates; and 4) conducted customer outreach and updated applicable Transmission Business Practices. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2019021067	BAL-005-0.2b	R17	Bonneville Power Administration	NCR05032	10/28/2017	9/20/2018	Self Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On February 15, 2019, the entity submitted a Self-Report stating that, as a Balancing Authority, it was in noncompliance with BAL-005-0.2b R17. Specifically, the entity has two Central Time Systems (CTSs) at two Control Centers that were not checked annually to calibrate the time error and frequency. The previous maintenance activities were performed October 27, 2016 and the subsequent checks would have been due October 28, 2017, but were not performed due to staffing changes in roles and responsibilities. The root cause of the issue was that the work was not properly reassigned to other staff when the personnel in charge of the CTS maintenance moved to another job. This issue began on October 29, 2017, when the entity missed the due date to perform the annual tests on the CTSs at two control centers and ended on September 20, 2018, when the entity completed the check for a total of 328 days. After reviewing all relevant information, WECC Enforcement determined that the entity failed to effectively perform BAL-005-0.2b R17.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the BPS. In this instance, the entity failed to at least annually check and calibrate its time error and frequency devices against a common reference, as required by BAL-005-0.2b R17. Each of the CTSs is made up of two independent GPS clocks with built-in 60Hz frequency cards, which are designed to do continuous calibration checks. Each clock does an internal calibration test to ensure that GPS time and Rubidium oscillator time agree within the specified accuracy. Failure to check and calibrate time error and frequency devices could potentially cause in an incorrect calculation of the frequency component of the ACE, which could result in over or under generation thus impacting the frequency of the interconnection. However, as compensation, the frequency and time error components are a relatively small component of the ACE equation. In addition, the CTSs provided the correct values and did not need to be recalibrated, significantly reducing any risk to the frequency of the BPS. No harm is known to have occurred. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity has: 2. checked its two CTSs at the two control centers against a common reference while adhering to the minimum values stated as in the Standard; and 3. per the retirement of BAL-005-0.2b R17 on December 31, 2018, thus no future mitigating steps were needed. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019523	FAC-013-2	R2	California Independent System Operator	NCR05048	July 1, 2017	October 31, 2017	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On January 29, 2018, the entity submitted a Self-Log stating, as a Planning Authority, it was in noncompliance with FAC-013-2 R2. Specifically, in June of 2017, the entity's Transfer Capability methodology was revised with an effective date of July 1, 2017 with the intent to post the revised Transfer Capability methodology to the entity's website and send emails to the required entities with the revised Transfer Capability by June 30, 2017. However, the entity did not post the revised methodology until September 9, 2017 and did not formally issue the Transfer Capability methodology to the required entities until October 31, 2017. The root cause of the issue was attributed to less than adequate controls. Specifically, there was not a checklist or similar control in place for the engineer revising the Transfer Capability methodology and the individual who usually provides a backup control was on a leave of absence. After reviewing all relevant information, WECC determined the entity failed FAC-013-2 R2. This noncompliance began on July 1, 2017, when properly distribute its revised Transfer Capability methodology to the required entities, and ended on October 31, 2017, when the Transfer Capability methodology was distributed, for a total of 123 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, the entity failed to issue its Transfer Capability methodology, and any revisions to the Transfer Capability methodology, prior to the effectiveness of such revisions, to the required entities, as required by FAC-013-2 R2. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) submitted the revised Transfer Capability methodology to the required entities; 2) updated its internal controls to include a checklist for issuing/revising the methodology; and 3) updated its process to include initiating the issuing of revisions well in advance of the effective date.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019524	INT-006-4	R1	California Independent System Operator	NCR05048	5/16/2017	5/16/2017	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On January 29, 2018, the entity submitted a Self-Log stating, as a Balancing Authority, it was in noncompliance with INT-006-4 R1. The entity reported that it did not respond to two of 103,257 Arranged Interchange requests (e-tags), within 10 minutes as defined in Attachment 1, Column B. Specifically, on May 16, 2017 these two e-tags were submitted less than one hour and less than or equal to 15 minutes prior to the ramp start, which would require the entity to approve or deny the e-tag within 10 minutes, according to Attachment 1, Column B of the Standard. The operational software was not processing e-tags as intended and the Interchange Scheduler recognized the issue and contacted the necessary personnel in IT to correct the issue. The Interchange Scheduler moved to deny the first e-tag, an additional three minutes and eight seconds, and the second e-tag five minutes and 27 seconds, after the 10 minute requirement. The root cause of the issue was a technical issue with its operational software. Specifically, the operational software's automated approval monitor was not processing e-tags at a normal rate. After reviewing all relevant information, WECC determined the entity failed INT-006-4 R1. This noncompliance started on May 16, 2017, when the entity failed to respond to two e-tags within the timeframe defined in the Standard and ended that same day when the two e-tags were denied, for a total of three minutes and eight seconds and five minutes and 27 seconds respectively.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, the entity failed to approve or deny two on-time Arranged Interchange or emergency Arranged Interchange that it received prior to the expiration of the time period defined in Attachment 1, Column B, as required by INT-006-4 R1. However, the entity considers these two failures statistically insignificant and to have had no reliability impact to the BPS. Additionally, as compensation, the failure included only two e-tags out of 103,257 and they were denied within a few minutes of the required timeframe. Additionally, each amount requested was only five MW, during the 23:00 hour, which was a time of low demand. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) denied the two e-tag requests; 2) reached out to the operational software to fix the delay in the e-tags being processed; and 3) received confirmation from the operational software that the delay issue had been resolved. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019525	INT-006-4	R2	California Independent System Operator	NCR05048	5/16/2017	5/16/2017	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On January 29, 2018, the entity submitted a Self-Log stating, as a Transmission Service Provider, it was in noncompliance with INT-006-4 R2. The entity reported that it did not respond to two of 103,257 Arranged Interchange requests (e-tags), within 10 minutes as defined in Attachment 1, Column B. Specifically, on May 16, 2017 these two e-tags were submitted less than one hour and less than or equal to 15 minutes prior to the ramp start, which would require the entity to approve or deny the e-tag within 10 minutes, according to Attachment 1, Column B of the Standard. The operational software was not processing e-tags as intended and the Interchange Scheduler recognized the issue and contacted the necessary personnel in IT to correct the issue. The Interchange Scheduler moved to deny the first e-tag, an additional three minutes and eight seconds, and the second e-tag five minutes and 27 seconds, after the 10 minute requirement. The root cause of the issue was a technical issue with its operational software. Specifically, the operational software's automated approval monitor was not processing e-tags at a normal rate. After reviewing all relevant information, WECC determined the entity failed INT-006-4 R2. This noncompliance started on May 16, 2017, when the entity failed to respond to two e-tags within the timeframe defined in the Standard and ended that same day when the two e-tags were denied, for a total of three minutes and eight seconds and five minutes and 27 seconds respectively.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, the entity failed to approve or deny two on-time Arranged Interchange or emergency Arranged Interchange that it received prior to the expiration of the time period defined in Attachment 1, Column B, as required by INT-006-4 R2. However, the entity considers these two failures statistically insignificant and to have had no reliability impact to the Bulk Power System. Additionally, as compensation, the failure included only two e-tags out of 103,257 and they were denied within a few minutes of the required timeframe. Additionally, each amount requested was only five MW, during the 23:00 hour, which was a time of low demand. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) denied the two e-tag requests; 2) reached out to the operational software to fix the delay in the e-tags being processed; and 3) received confirmation from the operational software that the delay issue had been resolved. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020875	MOD-025-2	R1; R1.2	Kern River Cogeneration Company (KRCC)	NCR05204	07/01/2016	10/01/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On December 20, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R1. Specifically, on October 1, 2018, KRCC discovered it did not submit a completed Attachment 2 to its Transmission Planner (TP) within 90 calendar days of verification of the Real and Reactive Power capabilities of four generating units, as required by the Standard. Although KRCC performed the verification for 100% of its generating units by June 2016, the responsible personnel at the time was not sure of the correct contact at the TP to send Attachment 2. After reviewing all relevant information, WECC Enforcement determined KRCC failed to effectively perform MOD-025-2 R1. The root cause of these issues was attributed to the KRCC's management's failure to oversee and ensure that the previous personnel responsible for providing Attachment 2 to its TP completed the task within 90 days. Additionally, KRCC did not adequately track or update the appropriate contacts of the TP. This issue began on July 1, 2016, when the Standard became mandatory and enforceable, and ended on October 1, 2018, when KRCC submitted the completed Attachment 2 forms for all four generating units to its TP, for a total of 823 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. KRCC had weak detective and preventative controls however, KRCC had implemented good compensating controls. Specifically, because the verification was performed in a timely manner, and the verification results were consistent with KRCC's plant design data that had been previously submitted to its TP for an Interconnection study. No harm is known to have occurred. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, KRCC: 1) submitted the completed Attachment 2 forms with verification of Real and Reactive Power capabilities of its generating units to its TP; 2) updated its MOD-025-2 procedure to include due dates and revalidation due dates; 3) validated that due dates for future MOD-025-2 requirements are identified in e-suites software program for tracking; 4) retained services of a third-party consultant to transfer its compliance responsibilities and program; and 5) will be transferring its compliance responsibilities and program to NAES. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020876	MOD-025-2	R2; R2.2	Kern River Cogeneration Company (KRCC)	NCR05204	07/01/2016	10/01/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On December 20, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R2. Specifically, on October 1, 2018, KRCC discovered it did not submit a completed Attachment 2 to its Transmission Planner (TP) within 90 calendar days of verification of the Real and Reactive Power capabilities of four generating units, as required by the Standard. Although KRCC performed the verification for 100% of its generating units by June 2016, the responsible personnel at the time was not sure of the correct contact at the TP to send Attachment 2. After reviewing all relevant information, WECC Enforcement determined KRCC failed to effectively perform MOD-025-2 R2. The root cause of these issues was attributed to the KRCC's management's failure to oversee and ensure that the previous personnel responsible for providing Attachment 2 to its TP completed the task within 90 days. Additionally, KRCC did not adequately track or update the appropriate contacts of the TP. This issue began on July 1, 2016, when the Standard became mandatory and enforceable, and ended on October 1, 2018, when KRCC submitted the completed Attachment 2 forms for all four generating units to its TP, for a total of 823 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. KRCC had weak detective and preventative controls however, KRCC had implemented good compensating controls. Specifically, because the verification was performed in a timely manner, and the verification results were consistent with KRCC's plant design data that had been previously submitted to its TP for an Interconnection study. No harm is known to have occurred. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, KRCC: 1) submitted the completed Attachment 2 forms with verification of Real and Reactive Power capabilities of its generating units to its TP; 2) updated its MOD-025-2 procedure to include due dates and revalidation due dates; 3) validated that due dates for future MOD-025-2 requirements are identified in e-suites software program for tracking; 4) retained services of a third-party consultant to transfer its compliance responsibilities and program; and 5) will be transferring its compliance responsibilities and program to NAES. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019750	EOP-004-3	R3	MaxGen Energy Services	NCR11636	1/1/2018	8/31/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On May 23, 2018, the entity submitted a Self-Report stating that, as a Generator Operator (GOP), it was in noncompliance with EOP-004-3 R3. The entity discovered during an internal compliance review that it did not review and update its Emergency Preparedness and Operations (EOP) contact information within its Operating Plan during the 2017 calendar year, per EOP-004-3 R3. This issue began on January 1, 2018, when the entity did not review and update EOP contract information during the 2017 calendar year and ended on August 31, 2018, when the entity reviewed and updated its EOP contact information for a total of 243 days. After reviewing all relevant information, WECC Enforcement determined that the entity failed to perform EOP-004-3 R3. The root cause of the issue was attributed to the lack of training of the entity's managers and operations staff in relation to internal procedures that were in place to ensure compliance of the EOP-004-3 R3.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year as required by EOP-004-3 R3. The entity implemented good detective controls to detect the above noncompliance. Specifically, the entity conducted an internal compliance reviews, during which the above issue was discovered. Furthermore, the issue was administrative in nature and could not have directly affected the BPS. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	The entity completed mitigating activities and on September 11, 2018, WECC verified the entity's mitigating activities. To remediate and mitigate this issue, the entity has: a. reviewed and updated EOP contact information; b. reinforced awareness of NERC Standards and compliance requirements with managers and operations staff; c. implemented a robust, organized electronic data warehouse to centrally catalog its procedures, compliance evidence, training materials, and all other related documentation; d. established a single contact point and calendar to centralize compliance related communications and scheduling; e. developed a centralized compliance calendar with automated reminders to ensure that critical due dates are not overlooked; and f. ensured quarterly management review to ensure procedures are followed for ongoing compliance.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019751	PRC-001-1.1(ii)	R1	MaxGen Energy Services	NCR11636	5/27/2016	7/20/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On May 23, 2018, the entity submitted a Self-Report stating that, as a Generator Operator (GOP), it was in noncompliance with PRC-001-1.1(ii) R1. The entity discovered during an internal compliance review that its Generator Operators did not consistently document and catalog all evidence regarding Operator training of Protection Systems schemes. This issue began on May 27, 2016, when the entity failed to ensure familiarity with the purpose and limitations of Protection System schemes applied in its area by not consistently documenting and cataloging all evidence regarding operator training on Protection Systems and ended on July 20, 2018, when the entity reviewed and updated it Operator training regarding Protection Systems for a total of 785 days. After reviewing all relevant information, WECC Enforcement determined the entity failed to properly evidence its performance PRC-001-1.1(ii) R1. The root cause of the issue was attributed to lack of training to the entity's Generator Operators in relation to internal procedures that were already in place to ensure compliance of the PRC-001-1.1(ii) R1.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the BPS. In this instance, the entity failed to be familiar with the purpose and limitations of Protection System schemes applied in its area as required by PRC-001-1.1 (ii) R1 by not consistently documenting and cataloging all evidence regarding operator training on Protection Systems. The entity implemented good detective controls to detect the above noncompliance. Specifically, the entity had a compliance review, during which the above issue was discovered. Furthermore, the issue was administrative in nature and could not have directly affected the BPS. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	The entity completed mitigating activities and on September 11, 2018, WECC verified the entity's mitigating activities. To remediate and mitigate this issue, the entity has: g. reviewed and updated all related procedures; h. developed a schedule to bring all applicable operations staff, including Generator Operators, current on training on Protection Systems; i. provided training to reinforce the awareness of NERC Standards and compliance requirements with managers and operations staff; j. implemented a robust, organized electronic data warehouse to centrally catalog its procedures, compliance evidence, training materials, and all other related documentation; k. established a single contact point and calendar to centralize compliance related communications and scheduling; l. identified and cataloged any existing training materials and related evidence, in addition to evidence going forward; m. ensured that all new operations personnel receive comprehensive training on Protection Systems in their area prior to beginning operations tasks; and n. developed quarterly management reviews to ensure that procedures are followed for ongoing compliance.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020591	VAR-002-4.1	R3	NAES – Panoche	NCR11518	10/11/2018	10/11/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On October 23, 2018, the entity submitted a Self-Report stating that, as a Generator Operator (GOP), it was in noncompliance with VAR-002-4.1 R3. Specifically, on October 10, 2018 the entity's 100 MVA generating unit experienced a control system card failure while returning from a scheduled semi-annual unit outage. During the replacement of the control card and repowering of the control system, the Power System Stabilizer (PSS) inadvertently defaulted to the disabled condition. On October 11, 2018, while the PSS was disabled, the 100 MVA generating unit was started by the night-shift lead operations and maintenance technician (LOMT) to meet a real-time dispatch, from 5:24 AM to 6:03 AM, a total of 39 minutes. At 9:00 AM the day-shift LOMT noticed that the PSS was disabled, at which time they enabled the PSS and notified plant management of the situation. The disabled PSS was not noticed during the unit startup and only came to light when the day-shift LOMT was reviewing plant conditions. The entity's Transmission Operator (TOP) was notified at 9:16 AM. After reviewing all relevant information, WECC Enforcement determined that the entity failed to properly perform VAR-002-4.1 R3. The root cause of the issue was attributed to the entity's insufficient start-up procedures. Specifically, the entities "Quick Start" procedure that was used during the plant startup was reviewed and found not to contain instruction to verify the status of the PSS prior to repowering a unit. WECC determined that this issue began on October 11, 2018 at 5:24 AM when there was a change to the PSS that was not reported to the TOP within 30 minutes of the change, and ended on October 11, 2018 at 9:16 AM when the TOP was notified of the status change of the PSS, for a total of 201 minutes.
Risk Assessment	WECC determined that this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to notify its associated TOP of a status change on the [power system stabilizer] within 30 minutes of the change, as required by VAR-002-4.1 R3. The entity implemented good compensating controls. Specifically, the entity's 100 MVA generating unit was only in operation for 39 minutes with the PSS in the disabled condition. During the time the unit was running there were no power system swings or concerns. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	The entity completed mitigating activities and, WECC verified the entity's mitigating activities. To remediate and mitigate this issue, the entity has: o. notified the TOP of the status change on the PSS; p. discontinued the use of quick start procedures; q. updated the integrated plant startup procedure for all plant startups; r. reviewed VAR-002 procedures with site operations and maintenance personnel, while emphasizing the importance of enabling the PSS during unit operations.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020112	EOP-004-3	R3	NAES Corporation - Sunnyside Cogeneration	NCR11830	2/5/2018	4/11/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On July 23, 2018, the entity submitted a Self-Report stating that, as a Generator Owner (GO) and Generator Operator (GOP), it was in noncompliance with EOP-004-3 R3. On February 5, 2018, the entity did not validate all contact information contained in its Operating Plan when it assumed compliance responsibility from another entity as a GOP and GO for its 65 MVA generating facility. This issue began on February 5, 2018, when the entity failed to validate all contact information contained in the Operating Plan and ended on April 11, 2018, when the entity validated all contact information in its Operating Plan for a total of 66 days. After reviewing all relevant information, WECC determined that the entity failed to perform EOP-004-3 R3 as described above. The root cause of the issue was a lack of dated contact validation records at the 65 MVA generating facility for the entity, to validate its compliance with the Standard, when it assumed compliance responsibility of another entity as a GOP and GO.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year, as required by EOP-004-3 R3. The entity implemented weak preventive or detective controls. However, as compensation, the issue was administrative in nature and thereby, very little risk to the BES. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	The entity completed mitigating activities and WECC verified completion of the entity's mitigating activities. To remediate and mitigate this issue, the entity has: s. validated contact information in its Operating Plan; and t. added an annual reminder to its maintenance management system for future contact validations as required by EOP-004 R3.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020815	PRC-019-2	R1; R1.1.; R1.1.1.; R1.1.2.	Saguaro Power Company, A Limited Partnership	NCR05369	7/1/2016	6/21/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On December 14, 2018, the entity submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with PRC-019-2 R1. Specifically, on March 24, 2017, the entity discovered it did not verify that it coordinated the voltage regulating system controls with the applicable equipment capabilities and settings of the applicable Protection Systems devices and functions for 40% of three combined cycle generating units by July 1, 2016, as required by the Implementation Plan for PRC-019-2. In July 2014, the parent company of the entity implemented a compliance approach for PRC-019-2 mistakenly believing that a fleet wide Facility count of all the Facilities for multiple registered entities under the same corporate structure could be used for determining which Facilities to include in the phases of the Implementation Plan. As a result, the entity's coordination for voltage regulating system controls was not performed for 40% of its Facilities, until June 21, 2017, when all the entity's applicable generating units were analyzed and verified. After reviewing all relevant information, WECC Enforcement determined SPC failed to effectively perform PRC-019-2 R1. The root cause of the issue was the parent corporation misunderstanding the requirements of the Implementation Plan for the Standard, resulting in SPC missing the July 1, 2016 deadline. This issue began on July 1, 2016, when the Standard became mandatory and enforceable and ended on June 21, 2017, when SPC completed the required analysis to verify voltage regulating controls and system protection coordination for its generating units, for a total of 355 days.
Risk Assessment	This noncompliance posed a minimal and did not pose a serious or substantial risk to the reliability of the bulk power system. SPC had weak preventative controls, however, SPC implemented good compensating controls. Specifically, no setting changes were needed for the existing relay settings and excitation controls. In addition, SPC's parent corporation implemented a program to ensure compliance on an Interconnection-wide basis. As a result, for the fleet of registered entities under this umbrella, 51.4% of generating facilities were compliant with the Standard in the Western Interconnection, thus reducing the risk to the Interconnection. Furthermore, SPC's three combined cycle generating units have a total nameplate capacity of about 120 MW, further reducing the risk. In addition, when SPC operated, no trips occurred due to inadequate coordination and when the entity performed the verification, no changes were required. No harm is known to have occurred. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this issue, SPC: 1) performed the required analysis to verify voltage regulating controls and system protection coordination for its generating units; 2) hired third-party consultants to perform required analysis of its generating units to verify regulating controls and system protection coordination; 3) formed internal NERC Steering Committee to oversee the development of new and revised NERC Standards as it applies to the entity's wholly owned and managed assets; and 4) developed a five-year NERC plan to address short-term, midterm, and long-term horizons for compliance with NERC Standards, based upon timing of enforcement. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020816	MOD-025-2	R1; R1.1.; R1.2.	Saguaro Power Company, A Limited Partnership	NCR05369	7/1/2016	5/8/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On December 14, 2018, SPC submitted a Self-Report stating that, as a GO, it was in noncompliance with MOD-025-2 R1. Specifically, on March 24, 2017, SPC discovered that it did not provide its Transmission Planner (TP) with verification of the Real and Reactive Power capabilities for its three combined cycle generating units, in accordance with Attachment 1 of the Standard, by the mandatory and enforceable date of the Standard. In July 2014, the parent company of SPC implemented a compliance approach for MOD-025-2 mistakenly believing that a fleet wide Facility count compliance approach for all the registered entities under the same corporate structure could be used for determining which Facilities to include to fulfill the requirements of the phases of the Implementation Plan. As a result, SPC's Real and Reactive Power capabilities were not verified for 40% of its Facilities according to the Standard until May 8, 2017, when SPC provided verification of the Real and Reactive Power capabilities of its generating units to its TP. After reviewing all relevant information, WECC Enforcement determined that SPC failed to properly perform MOD-025-2 R1. The root cause of the issue was the parent corporation misunderstanding the requirements of the Implementation Plan for the Standard, resulting in SPC missing the July 1, 2016 deadline. This issue began on July 1, 2016, when the Standard became mandatory and enforceable and ended on May 8, 2017, when SPC provided verification of Real and Reactive Power capabilities of its generating units to its TP, for a total of 311 days.
Risk Assessment	This noncompliance posed a minimal and did not pose a serious or substantial risk to the reliability of the bulk power system. SPC had weak preventative controls, however, SPC had implemented good compensating controls. Specifically, the testing did not reveal any major discrepancies from previously reported Real and Reactive capabilities. Furthermore, SPC's three combined cycle generating units have a total nameplate capacity of about 120 MW, further reducing the risk. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate these issues, SPC: 1) completed and submitted required Real and Reactive Power capabilities testing to its TP; 2) developed and implemented a process for the internal review of test data and submission prior to submittal to its TP to ensure all required data has been properly collected and submitted; 3) formed internal NERC Steering Committee to oversee the development of new and revised NERC Standards as it applies to the entity's wholly owned and managed assets; and 4) developed a five-year NERC plan to address short-term, midterm, and long-term horizons for compliance with NERC Standards, based upon timing of enforcement. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020817	MOD-025-2	R2; R2.1.; R2.2.	Saguaro Power Company, A Limited Partnership	NCR05369	7/1/2016	5/8/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On December 14, 2018, SPC submitted a Self-Report stating that, as a GO, it was in noncompliance with MOD-025-2 R2. Specifically, on March 24, 2017, SPC discovered that it did not provide its Transmission Planner (TP) with verification of the Real and Reactive Power capabilities for its three combined cycle generating units, in accordance with Attachment 1 of the Standard, by the mandatory and enforceable date of the Standard. In July 2014, the parent company of SPC implemented a compliance approach for MOD-025-2 mistakenly believing that a fleet wide Facility count compliance approach for all the registered entities under the same corporate structure could be used for determining which Facilities to include to fulfill the requirements of the phases of the Implementation Plan. As a result, SPC's Real and Reactive Power capabilities were not verified for 40% of its Facilities according to the Standard until May 8, 2017, when SPC provided verification of the Real and Reactive Power capabilities of its generating units to its TP. After reviewing all relevant information, WECC Enforcement determined that SPC failed to properly perform MOD-025-2 R2. The root cause of the issue was the parent corporation misunderstanding the requirements of the Implementation Plan for the Standard, resulting in SPC missing the July 1, 2016 deadline. This issue began on July 1, 2016, when the Standard became mandatory and enforceable and ended on May 8, 2017, when SPC provided verification of Real and Reactive Power capabilities of its generating units to its TP, for a total of 311 days.
Risk Assessment	This noncompliance posed a minimal and did not pose a serious or substantial risk to the reliability of the bulk power system. SPC had weak preventative controls, however, SPC had implemented good compensating controls. Specifically, the testing did not reveal any major discrepancies from previously reported Real and Reactive capabilities. Furthermore, SPC's three combined cycle generating units have a total nameplate capacity of about 120 MW, further reducing the risk.
Mitigation	To mitigate these issues, SPC: 1) completed and submitted required Real and Reactive Power capabilities testing to its TP; 2) developed and implemented a process for the internal review of test data and submission prior to submittal to its TP to ensure all required data has been properly collected and submitted; 3) formed internal NERC Steering Committee to oversee the development of new and revised NERC Standards as it applies to the entity's wholly owned and managed assets; and 4) developed a five-year NERC plan to address short-term, midterm, and long-term horizons for compliance with NERC Standards, based upon timing of enforcement. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017018111	COM-001-2.1	R10	Tri-State Generation and Transmission Association, Inc.	NCR10030	10/8/2016	10/8/2016	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On August 3, 2017 the entity submitted a Self-Report stating, as a Transmission Operator (TOP), it was in issue of COM-001-2.1 R10. Specifically, on October 8, 2016, at 9:10 AM, the entity detected that its phone system, its Interpersonal Communication, had inadvertently went out of service during its backup Control Center (BCC) functional exercise. At 9:25 AM, a notification was sent out through the Reliability Coordinator's (RC) Reliability Message Tool (RMT) to 18 of the 29 required recipients within the entity's footprint including RCs, TOP, and Balancing Authorities (BA) alerting them that its primary Interpersonal Communication capability was down and provided two alternative contact phone numbers. Further, at 10:28 AM, a notification was sent out through the RMT, notifying 18 of the 29 entities that the phone lines were back in service and that the primary contact phone number could again be used. However, 9 of the 29 entities, consisting of five Distribution Providers (DP), three Generator Operators (GOP), and one TOP in the adjacent Midwest Reliability Organization (MRO) region that were required to be notified of the outage by the Standard, did not receive notification of the detection of a failure of the entity's Interpersonal Communication capability because these entities were not listed on the RMT list of recipients. Two additional entities were also not on the RMT list of recipients but were called and notified that the BCC functional exercise was completed at 10:50 AM. Therefore, 11 of the 29 entities within the entity's footprint were not notified of the phone outage by 10:10 AM as required by the Standard. After reviewing all relevant information, WECC determined the entity failed to notify 11 of the 29 entities within its footprint as required by COM-001-2.1 R10, within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasted 30 minutes or longer. The root cause of the issue was the entity not ensuring its procedural documents and programs for the notification of Interpersonal Communication were sufficient to comply with COM-001-2.1 R10. Specifically, there was an error in the procedural documents that specified the incorrect time allowed for notifying entities of issues, and 11 entities were missing from the RMT list. This issue began on October 8, 2016 at 9:10 AM when the entity failed to notify 11 of the 29 entities identified in COM-001-2.1 R1, R3, and R5 within 60 minutes of the detection of the failure of its interpersonal communication capability, and ended on October 8, 2016 at 10:28 AM when the entity's Interpersonal Communication capability came back into service, 18 minutes past the time required by the Standard.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to notify 11 of the 29 entities within its footprint as required by COM-001-2.1 R10, within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasted 30 minutes or longer. The entity did not have adequate preventative or detective controls. However, BPS instability, separation, or cascading outages are not likely to occur due to a failure to notify another entity of the failure of Interpersonal Communication capability. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To remediate and mitigate this issue, the entity has: a. updated its existing procedure to better align with the COM-001-2.1 standard regarding the allotted time allowed for notifying entities following a communications failure. b. created a manual notification checklist used to track and document notifications to all applicable parties including the entities that were not previously on the RMT notification list; and c. ensured that operators are aware of and trained on the updated procedures for COM-001.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019687	COM-002-4	1	Tri-State Generation and Transmission Association, Inc.	NCR10030	7/1/2016	7/13/2018	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	During a Compliance Audit conducted April 9, 2018, through April 20, 2018, WECC determined that the entity, as a Transmission Operator (TOP), was in issue with COM-002-4 R1. WECC Auditors determined the entity misinterpreted the term "operating personnel" too restrictively, in its COM-002-4 R1 communication protocol for issuance and receipt of Operating Instructions, to include only its Transmission System Operators. During the April 2018 WECC Compliance Audit, WECC auditors indicated that the term "operating personnel" should have also included field personnel, because they can change or preserve the state, status, output, or input of an Element or Facility of the Bulk Electric System (BES). The entity did not include field personnel or Generator Operators in its documented communications protocols, as required by the Standard. After reviewing all relevant information, WECC determined the entity failed to develop documented communications protocols for all operating personnel that receive Operating Instructions as required by COM-002-4 R1 Part 1.3. The root cause of the issue was the entity's misinterpretation "operating personnel" and instead specified its own definition to only include Transmission System Operators. This issue began on July 1, 2016, when the Standard and Requirement became mandatory and enforceable, and ended on July 13, 2018, when TSGT updated its communication protocol to include the corrected definition of "operating personnel," for a total of 743 days.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the BPS. In this instance, the entity failed to develop documented communication protocols for all operating personnel that receive Operating Instructions as required by COM-002-4 R1, Part 1.3. The entity did not have preventative or detective controls to detect the above non-compliance issue. In addition, although the entity's documented communication protocols for "operating personnel" did not include "field personnel," field personnel were still trained in how to issue and receive Operating Instructions as if they were included in the definition. Therefore, it is highly unlikely that there would be an impact to the reliability of the BES because the issue was purely administrative in nature. WECC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To remediate and mitigate this issue, the entity has: a. updated the internal definition of operating personnel to include field personnel in its Communication Protocol; and b. updated its Communication Protocol for issuance and receipt of Operating Instructions.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017118	MOD-025-2	R1; R1.1.; R1.2.2.	Windstar Energy, LLC	NCR11292	7/1/2016	12/19/2018	Self-Certification	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On February 28, 2017, WSTAR submitted a Self-Certification stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R1. Specifically, on February 28, 2017, WSTAR discovered it did not provide its Transmission Planner (TP) with verification of the Real and Reactive Power capabilities for its two wind generating units, in accordance with Attachment 1 of the Standard, by the mandatory and enforceable date of the Standard. In February 2017, through WSTAR's annual Self Certification review, it learned that its parent company misunderstood the applicability of the type of generating units that were applicable to the Standard. As a result, WSTAR's Real and Reactive Power capabilities were not verified for 40% of its Facilities according to the implementation timeline for the Standard. After reviewing all relevant information, WECC Enforcement determined that WSTAR failed to properly perform MOD-025-2 R1. The root cause of these issues was attributed to WSTAR's parent company misunderstanding the applicability of the Standard to WSTAR's generating units, as such, WSTAR missed the July 1, 2016 deadline. Specifically, the parent company did not realize the new Standard applied to its two wind generating units until the Self-Certification review. This issue began on July 1, 2016, when the Standard became mandatory and enforceable and ended on December 19, 2018, when WSTAR provided verification of the Real and Reactive Power capabilities of its generating units to its Transmission Planner, for a total of 902 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. WSTAR had weak preventative controls, however, as compensation, wind generation is typically not utilized as a firm resource due to the unpredictability of wind. Therefore, Balancing Authorities, Transmission Operators and Transmission Owners plan and operate the grid with the expectation that wind generation may be unavailable at any time. In addition, the data gained by the Requirement is used for planning purposes to improve the accuracy of the system models used to develop contingencies and operating limits. This issue could not likely have directly affected the BPS. WSTAR does not have any relevant previous violations of this or similar Standards and Requirements.
Mitigation	To mitigate this issue, WSTAR: 2. hired third party to perform verification testing of all its wind generating units; 3. completed and submitted required Real and Reactive Power capabilities testing to its TP; and 4. implemented a compliance tracking tool to assist with management of future changes to NERC Reliability Standards. WECC has verified all mitigating activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017119	MOD-025-2	R2; R2.1.; R2.2.	Windstar Energy, LLC	NCR11292	7/1/2016	12/19/2018	Self-Certification	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On February 28, 2017, WSTAR submitted a Self-Certification stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R2. Specifically, on February 28, 2017, WSTAR discovered it did not provide its Transmission Planner (TP) with verification of the Real and Reactive Power capabilities for its two wind generating units, in accordance with Attachment 1 of the Standard, by the mandatory and enforceable date of the Standard. In February 2017, through WSTAR's annual Self Certification review, it learned that its parent company misunderstood the applicability of the type of generating units that were applicable to the Standard. As a result, WSTAR's Real and Reactive Power capabilities were not verified for 40% of its Facilities according to the implementation timeline for the Standard. After reviewing all relevant information, WECC Enforcement determined that WSTAR failed to properly perform MOD-025-2 R2. The root cause of these issues was attributed to WSTAR's parent company misunderstanding the applicability of the Standard to WSTAR's generating units, as such, WSTAR missed the July 1, 2016 deadline. Specifically, the parent company did not realize the new Standard applied to its two wind generating units until the Self-Certification review. This issue began on July 1, 2016, when the Standard became mandatory and enforceable and ended on December 19, 2018, when WSTAR provided verification of the Real and Reactive Power capabilities of its generating units to its Transmission Planner, for a total of 902 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. WSTAR had weak preventative controls, however, as compensation, wind generation is typically not utilized as a firm resource due to the unpredictability of wind. Therefore, Balancing Authorities, Transmission Operators and Transmission Owners plan and operate the grid with the expectation that wind generation may be unavailable at any time. In addition, the data gained by the Requirement is used for planning purposes to improve the accuracy of the system models used to develop contingencies and operating limits. This issue could not likely have directly affected the BPS. WSTAR does not have any relevant previous violations of this or similar Standards and Requirements.
Mitigation	To mitigate this issue, WSTAR: 1. hired third party to perform verification testing of all its wind generating units; 2. completed and submitted required Real and Reactive Power capabilities testing to its TP; and 3. implemented a compliance tracking tool to assist with management of future changes to NERC Reliability Standards. WECC has verified all mitigating activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
FRCC2019021582	PRC-006-3	R9.	Gainesville Regional Utilities (GRU)	NCR00032	2/21/2018	2/6/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed noncompliance.)	On May 20, 2019, GRU submitted a Self-Report stating that, as a Distribution Provider and Transmission Owner, it was in noncompliance with PRC-006-3 R9. This noncompliance started on February 21, 2018, when GRU failed to properly set the time delay for one (1) of their Under-Frequency Load Shedding (UFLS) relays to provide automatic tripping of Load in accordance with the UFLS program as determined by its Planning Coordinator (PC), and ended on February 6, 2019 (350 days), when GRU adjusted the time delay for the UFLS relay to meet the Planning Coordinator parameters. On February 6, 2019, during the annual preparation for submitting UFLS data to the Planning Coordinator (FRCC), GRU discovered that one (1) UFLS relay time delay setting had been set incorrectly to 0.15 seconds instead of the correct value of 15 seconds. The incorrect setting had been in place since February 21, 2018. Had an UFLS event occurred during this time period, the tripping of Load would not have been in accordance with the FRCC's UFLS program design and schedule for implementation. GRU performed an extent of condition discovering no additional instances of noncompliance. The cause for this noncompliance was due to misinterpretation of the value to be set by the relay technician.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk was minimal because the incorrectly set relay only controlled load shedding for nine (9) MWs. If a UFLS event had occurred, 96% of GRU's UFLS relays would have shed load at the appropriate time delay requirement, while the remaining 4% would have shed load faster than required. Furthermore, there were no UFLS events during the period of noncompliance. GRU's 185 MWs of UFLS Load Shed represents 0.9% of the Regional UFLS Load Shed. No harm is known to have occurred. The Region determined that the Entity's compliance history should not serve as a basis for applying a penalty.
Mitigation	To mitigate this noncompliance, GRU: 1) performed an extent of condition analysis for all UFLS settings; 2) corrected the time setting delay to the correct value; 3) revised the UFLS relay settings procedure to require (1) a typed copy of the new settings for the relay techs to reference, to avoid confusion over hand-written values, and (2) a sign-off approval for the as-left settings package by Supervising Engineer for Substations & Relays; and 4) trained all applicable personnel on the procedure changes.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SPP2018019054	PRC-005-2(i)	R3	CPV Keenan II Renewable Energy Company, LLC (KREC)	NCR11081	10/01/2015	01/20/2018	Self-Certification	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 26, 2018, KREC submitted a Self-Certification stating that, as a Generator Operator, it was in noncompliance with PRC-005-2(i) R3. Specifically, KREC stated that it did not perform the cell/unit internal ohmic value measurements every six months on its Valve-Regulated Lead-Acid (VRLA) batteries as required by Table 1-4(b). The cause of the noncompliance was an error in updating its Protection System Maintenance Program (PSMP); KREC reports that when it updated its PSMP in 2015, it included Table 1-4(a) for Vented Lead-Acid (VLA) batteries instead of Table 1-4(b) for VRLA batteries. Table 1-4(a) does not include the requirement that the internal ohmic value is measured every six months. This noncompliance started on October 1, 2015, when the six-month maintenance interval in Table 1-4(b) became enforceable under the implementation plan, and ended on January 20, 2018, when all the required maintenance was performed.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. KREC states that the batteries were getting regular maintenance pursuant to the schedule in Table 1-4(a), meaning that all other required activities other than the internal ohmic value measurement were being performed. Further, KREC reports that no issues were identified during the other maintenance activities that were conducted during the noncompliance and no issues were identified when the batteries received their internal ohmic value measurement. Additionally, the noncompliance did not involve a Facility that is a Blackstart Resource, associated with a Remedial Action Scheme (RAS), or any Interconnection Reliability Operating Limit (IROL). Finally, KREC has a generation profile of approximately 152 MW that is considered Low Risk per its completed Inherent Risk Assessment (IRA). No harm is known to have occurred. KREC has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, KREC: 1) incorporated the correct maintenance table into its PSMP; 2) measured the internal ohmic value on all applicable VLRA batteries; 3) implemented improvements to its document management systems for updating the PSMP; 4) implemented additional maintenance activity tracking systems; and 5) had its facility manager attend a battery maintenance and testing course.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SPP2018019087	VAR-002-4	R2	CPV Keenan II Renewable Energy Company, LLC (KREC)	NCR11081	09/12/2017	11/18/17	Self-Certification	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 26, 2018, KREC submitted a Self-Certification stating that, as a Generator Operator, it was in noncompliance with VAR-002-4 R2. KREC failed to maintain the specified generator voltage schedule when it switched from Automatic Voltage Regulator (AVR) mode into power factor mode. The cause of the noncompliance was a result of a misinterpretation of its interconnection agreement; KREC believed that under the agreement it had the option to operate in either AVR mode or power factor mode. The noncompliance began on September 12, 2017, when KREC began operating in power factor mode, and ended on November 18, 2017, when KREC returned its operations to AVR mode.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. KREC states that its TOP and its Reliability Coordinator have monitoring capability and alarms set for the point of generation interconnection and could have contacted KREC for any needed changes in voltage or changes in generation output. Additionally, the noncompliance did not involve a Facility that is a Blackstart Resource, associated with a Remedial Action Scheme (RAS), or any Interconnection Reliability Operating Limit (IROL). Finally, KREC has a generation profile of approximately 152 MW that is considered Low Risk per its completed Inherent Risk Assessment (IRA). No harm is known to have occurred. KREC has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, KREC: 1) returned its generation to AVR mode; 2) provided training to Generator Operators on the requirements to notify its TOP of operational changes; 3) made changes to its VAR-002-4.1 procedure to reflect process steps regarding informing its TOP about voltage excursions; 4) committed to annually reviewing its process used to notify its TOP of voltage excursions; 5) committed to using the 2018 Voltage Schedule Notification letter provided by its TOP; and 6) discussed the notification process with its TOP.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SPP2018019088	VAR-002-4	R3	CPV Keenan II Renewable Energy Company, LLC (KREC)	NCR11081	09/12/2017	11/18/17	Self-Certification	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 26, 2018, KREC submitted a Self-Certification stating that, as a Generator Operator, it was in noncompliance with VAR-002-4 R3. KREC changed from Automatic Voltage Regulator (AVR) mode to power factor mode and failed to notify its Transmission Operator (TOP) within 30 minutes of the change. The cause of the noncompliance was a result of a misinterpretation of its interconnection agreement; KREC believed that under the agreement it had the option to operate in either AVR mode or power factor mode. The noncompliance began on September 12, 2017, when KREC did not notify its TOP within 30 minutes of switching from operating in AVR mode to power factor mode, and ended on November 18, 2017, when KREC returned its operations to AVR mode.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. KREC states that its TOP and its Reliability Coordinator have monitoring capability and alarms set for the point of generation interconnection and could have contacted KREC for any needed changes in voltage or changes in generation output. Additionally, the noncompliance did not involve a Facility that is a Blackstart Resource, associated with a Remedial Action Scheme (RAS), or any Interconnection Reliability Operating Limit (IROL). Finally, KREC has a generation profile of approximately 152 MW that is considered Low Risk per its completed Inherent Risk Assessment (IRA). No harm is known to have occurred. KREC has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, KREC: 1) returned its generation to AVR mode; 2) provided training to Generator Operators on the requirements to notify its TOP of operational changes; 3) made changes to its VAR-002-4.1 procedure to reflect process steps regarding informing its TOP about voltage excursions; 4) committed to annually reviewing its process used to notify its TOP of voltage excursions; 5) committed to using the 2018 Voltage Schedule Notification letter provided by its TOP; and 6) discussed the notification process with its TOP.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SPP2018019091	VAR-002-4	R1	CPV Keenan II Renewable Energy Company, LLC (KREC)	NCR11081	09/12/2017	11/18/2017	Self-Certification	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 26, 2018, KREC submitted a Self-Certification stating that, as a Generator Operator, it was in noncompliance with VAR-002-4 R1. KREC operated in power factor mode rather than Automatic Voltage Regulator (AVR) mode as instructed by its Transmission Operator (TOP) and it failed to notify its TOP of the change in mode. The cause of the noncompliance was a result of a misinterpretation of its interconnection agreement; KREC believed that under the agreement it had the option to operate in either AVR mode or power factor mode. The noncompliance began on September 12, 2017, when KREC began operating in power factor mode, and ended on November 18, 2017, when KREC returned its operations to AVR mode.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. KREC states that its TOP and its Reliability Coordinator have monitoring capability and alarms set for the point of generation interconnection and could have contacted KREC for any needed changes in voltage or changes in generation output. Additionally, the noncompliance did not involve a Facility that is a Blackstart Resource, associated with a Remedial Action Scheme (RAS), or any Interconnection Reliability Operating Limit (IROL). Finally, KREC has a generation profile of approximately 152 MW that is considered Low Risk per its completed Inherent Risk Assessment (IRA). No harm is known to have occurred. KREC has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, KREC: 1) returned its generation to AVR mode; 2) provided training to Generator Operators on the requirements to notify its TOP of operational changes; 3) made changes to its VAR-002-4.1 procedure to reflect process steps regarding informing its TOP about voltage excursions; 4) committed to annually reviewing its process used to notify its TOP of voltage excursions; 5) committed to using the 2018 Voltage Schedule Notification letter provided by its TOP; and 6) discussed the notification process with its TOP.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2019020997	PRC-001-1.1(ii)	R3	Board Of Public Utilities, City Of McPherson, Kansas (MCPHER)	NCR10319	11/14/2016	01/16/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 16, 2019, MCPHER submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with PRC-001-1.1(ii) R3. MCPHER states that on November 14, 2016, it implemented protection system changes on a gas turbine unit but did not coordinate those changes with its Transmission Operator or its Balancing Authority as required by R3.1. The cause of the noncompliance is that MCPHER failed to follow its documented procedure. The noncompliance began on November 14, 2016, when the protection system changes were implemented, and ended on January 16, 2019, when MCPHER coordinated those changes with its Transmission Operator and Balancing Authority.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. This Standard and Requirement is being replaced on October 1, 2020 with PRC-027-1, which does not require a Generator Owner or Generator Operator to coordinate protection system changes with its Transmission Operator or its Balancing Authority. Additionally, MCPHER's nameplate generation capacity is 230 MVA which meets the low risk criteria for ERO Risk Factors. Finally, the impacted generation interconnects at 115 kV further limiting the potential risk. No harm is known to have occurred. MCPHER has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, MCPHER: 1) coordinated its protection system changes with its Transmission Operator and Balancing Authority; and 2) held a meeting to review and reinforce the documented procedure for communicating protection system changes.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2017018452	PRC-004-5(i)	R1	MidAmerican Energy Company (MEC)	NCR00824	7/5/2017	10/4/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from September 18, 2017 through September 19, 2017, MRO determined that MEC, as a Transmission Owner, was in noncompliance with PRC-004-5(i) R1. On March 6, 2017, a Zone 1 ground distance relay at a terminal of a 161 kV line misoperated and tripped during a bus fault at another substation. MEC submitted a misoperation report to the Misoperation Information Data Analysis System (MIDAS) on June 8, 2017. However, on June 27, 2017, MEC informed MRO that after further analysis, it determined that the relays operated as designed for the fault scenario and removed the submittal from its Q1 2017 MIDAS Spreadsheet. The Compliance Audit team reviewed the event and determined that the relay operation did constitute a misoperation. MRO determined that the ground distance Zone 1 setting did not properly account for the mutual coupling between the double circuit transmission lines at the Facility and this relay operation was an unnecessary trip. MEC added the misoperation back into the MIDAS database on October 4, 2017. The cause of the noncompliance was that MEC failed to consider mutual coupling between transmission lines near the Black Hawk substation when identifying whether the Protection System components caused a misoperation. The noncompliance began on July 5, 2017, 121 days after the misoperation, and ended October 4, 2017 when MEC reported the misoperation.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The noncompliance involved a Protection System on a 161 kV Transmission Line that does not protect elements of a Cranking Path, a Remedial Action Scheme (RAS), or an Interconnection Reliability Operating Limit (IROL). Further, the negative impact to the system resulting from the relay misoperation was limited to 318 customers being interrupted for about one-half of a second (18.5 MVA of load). Finally, the MRO Protective Relay Subcommittee has observed that reliability is more substantially threatened by a relay's failure to operate as compared to a relay's unnecessary operation. No harm is known to have occurred as a result of the noncompliance. MEC has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, MEC: 1) updated its MIDAS data to include the misoperation; and 2) developed and implemented a Corrective Action Plan for PRC-004-5(i) R5, the CAP included a review of numerous line impedances to evaluate mutual coupling effects on relay settings. MRO verified completion of the mitigating activities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020130	TOP-001-3	R13	Northern States Power (Xcel Energy) (NSP)	NCR01020	06/08/2018	06/17/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 10, 2018, NSP, a Coordinated Oversight Program participant, submitted a self-log to MRO stating that, as a Transmission Owner, and Transmission Operator, it was in noncompliance with TOP-001-3 R13. NSP, Public Service Company of Colorado (PSCO) (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program. The self-log identified two instances of noncompliance. The noncompliance occurred in NSP. In the first instance of noncompliance a Real-time Assessment (RTA) was not performed at least once every thirty minutes on June 8, 2018. Xcel Energy states that the system will begin issuing a continuous alarm if an RTA is not performed at least every 20 minutes. Xcel Energy experienced a non-convergence of its Real-time Contingency Analysis (RTCA) tool that prevented an RTA from being performed from 8:41 a.m. to 9:51 a.m. Xcel Energy states that it asked that its Reliability Coordinator (RC) perform RTAs until its capabilities were restored. Xcel Energy states that its RC performed an RTA on Xcel Energy's behalf at 9:15 a.m. Xcel Energy indicates that the System Operator did not promptly respond to the alarm and make this request to the RC, resulting in a 34 minute gap between the last RTA Xcel Energy performed and the RTA that its RC performed. In the second instance of noncompliance an RTA was not performed at least once every thirty minutes on June 17, 2018. Xcel Energy states that the system will begin issuing a continuous alarm if an RTA is not performed at least every 20 minutes. Xcel Energy experienced a non-convergence of its Real-time Contingency Analysis (RTCA) tool that prevented an RTA from being performed from 1:05 a.m. to 1:36 a.m. Xcel Energy states that in response to the alarm, instead of implementing the documented procedure, the System Operator began troubleshooting, believing it was caused by stale substation data from a Remote Terminal Unit that went down a few hours previously. The System Operator was able to correct the issue and an RTA was successfully performed at 1:36 a.m., which represents a 31 minute gap. The noncompliance was caused by Xcel Energy not implementing the applicable procedure to promptly notify the RC to ensure that an RTA is performed at least every thirty minutes. The noncompliance was noncontiguous; the noncompliance began on June 8, 2018, when an RTA was not performed at least every 30 minutes, and ended on June 17, 2018, when an RTA was performed correctly.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. During the noncompliance, Xcel Energy states that the RC's processes were functioning and solving for the RC's system that included NSP, and that if the RC were to detect an adverse condition in NSP's system, it would have contacted Xcel Energy. Further, Xcel Energy did not experience a line or generator trip during the period of noncompliance. Finally, both instances were brief. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, Xcel Energy: 1) resumed performing an RTA at least every thirty minutes; 2) reminders were created for NSP's System Operators to ensure that the RC's RTA needs to be acquired within 30 minutes of a failure; and 3) an internal issue notification was distributed to other System Operations departments within Xcel Energy as part of an internal peer sharing program.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020125	MOD-026-1	R2	Odell Wind Farm, LLC (OWF)	NCR11683	07/01/2018	07/25/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 24, 2018, OWF submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-026-1 R2. OWF is part of an MRRE Group that includes: Algonquin Power Co. (NCR11785) that is registered in MRO, ReliabilityFirst (RF), Western Electricity Coordinating Council (WECC), and Texas Reliability Entity (TRE); The Empire District Electric Company (NCR01155) that is registered in MRO; CalPECo (NCR11439) that is registered in WECC; and Granite State Electric Company (NCR11439) that is registered in Northeast Power Coordinating Council (NPCC) (collectively referred to as APC). The noncompliance impacted OWF and two of Algonquin Power Co.'s renewable generation facilities that are located in RF and until May 1, 2019, were separately registered as Deerfield Wind Energy (NCR11691) and GSG6 (NCR11247). Under the phased implementation plan OWF, Deerfield Wind Energy, and GSG6 were required to provide verification of 100% of their units by July 1, 2018. APC had contracted with third-parties to complete these verification studies. APC states that the verification of the plant volt/var control function model for these Facilities was not finalized and sent to the Transmission Planner (TP) until July 24, 2018 and that a verification of the generator excitation control system was completed for these Facilities prior to July 1, 2018, but was not distributed to the TP until July 25, 2018. The cause of the noncompliance is that APC failed to ensure that third-party contractors had completed the verification studies in time to meet the requirement. The noncompliance began on July 1, 2018, when the Standard and Requirement became enforceable, and ended on July 25, 2018, when the studies were completed and transmitted to the TP.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The noncompliance impacted three wind farms that each had a nameplate rating lower than 200 MW which represents a minimal potential impact to the voltage/var support for the system. No harm is known to have occurred. APC has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, OWF: 1) completed the model verification studies; 2) submitted the model verification reports to the TP; and 3) implemented an electronic task tool and populated the tool with NERC compliance reminders. The mitigating activities were limited to OWF and Algonquin Power Co.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020124	TOP-001-3	R9	City Utilities Of Springfield, MO (SPRM)	NCR01081	04/02/2018	04/02/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 10, 2018, SPRM submitted a self-log stating that, as a Transmission Operator it was in noncompliance with TOP-001-3 R9. SPRM reports that for approximately one hour on April 2, 2018, it experienced a loss of SCADA capabilities for all of the Remote Terminal Units (RTUs). SPRM states that it promptly notified its Reliability Coordinator and two of its three interconnected registered entities. The cause of the noncompliance is that the System Operator failed to follow SPRM's documented procedure to provide notification to all impacted interconnected registered entities. The noncompliance began on April 2, 2018, when SPRM failed to notify an impacted interconnected registered entity of the loss of its RTUs' SCADA capabilities, and ended later that day, April 2, 2018, when the RTUs regained SCADA capabilities.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. SPRM did not experience a loss of any transmission or generation Facilities during the event. Additionally, during the noncompliance, SPRM states that it was able to monitor generation via telephone and access ICCP tie-line data at the interconnections regarding the flows and transmission voltages, as that information was provided by adjacent Transmission Operators. Finally, SPRM's Transmission Facilities are not associated with a Remedial Action Scheme (RAS) or Interconnection Reliability Operating Limit (IROL). No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, SPRM: 1) regained SCADA capability; and 2) reiterated the importance of following the documented procedure to the System Operator.

NERC Noncompliance ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Mitigation Completion Date
NPCC2019021382	MOD-025-2	R1	Helix Maine Wind Development, LLC	NCR11766	8/2/2017	Present	Self-Report	Expected Completion 10/29/2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On April 18, 2019, Helix Maine Wind Development, LLC (Kibby Wind) submitted a Self-Report stating that as a Generator Owner (GO), it had discovered it was in noncompliance with MOD-025-2 R1. Kibby Wind failed to provide its Transmission Planner (TP) with verification of its real power capability within 90 days of the test completion. Kibby Wind became a new NERC registered entity on August 2, 2017 upon purchase from the previous owner. As part of the sale process, the previous owner provided the facility's compliance documentation for the NERC Reliability Standards including MOD-025-2. During an internal review, Kibby Wind found that although the test had been completed, it did not have appropriate documentation to demonstrate that the real test results had been submitted to the New England ISO TP within 90 days of the test completion by the previous owner. From the documentation, it was determined that the real power test was performed on June 28, 2016. The previous owner had indicated that they obtained the test results and then submitted operational data for the real test in November 2016, but Kibby Wind was unable to find evidence that the previous owner actually submitted the test data to the TP. Kibby Wind contacted both the New England ISO and the previous owner to determine if the test data had been submitted as required, however, no evidence of provision to the TP could be found. This noncompliance started on August 2, 2017, when Kibby Wind's GO function became effective and will end on October 29, 2019, when a new test will be completed and the results will be submitted to the TP. The root cause of this noncompliance was a lack of retention of proper compliance records by the previous owner and a seemingly lack of a clear understanding by the previous owner to submit the test results to the TP within 90 days of completion of the staged test.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Specifically, by failing to provide the test results to the TP within 90 days, the TP could have inaccurate information about the generating units when developing planning models to assess BPS reliability. However, Kibby Wind is a 132 MVA facility and its applicable facilities consist of 44 wind turbines at 3 MVA each. The facility has had a capacity factor of 27.15% in 2016, 27.70% in 2017, and 25.09% in 2018. The rated capability of the site is 6% of the ISONE typical required Operating Reserve (approximately 2,200 MW). The required testing is scheduled for the end of July 2019. Additionally, because the facility is an intermittent wind generator, its ability to supply real power is limited by the environmental conditions at the facility. The MOD-025 standard recognizes this and the requirement in Attachment 1 is to obtain the maximum real power lagging output provided at the time of the test. The information supplied to the TP is not necessarily the actual capability of the facility. This limitation is understood by the TP and is worked into their model for distributed wind facilities. No harm is known to have occurred as a result of this noncompliance. NPCC considered Kibby Wind's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Kibby Wind will complete the following mitigation activities by October 29, 2019: 1) schedule and complete real power testing when 90% of wind turbines can be online; 2) complete MOD-025-2 awareness training for plant personnel; 3) provide completed testing results to TP; and 4) utilize GenSuite Scheduling System to schedule future testing and TP notification reminders within five years (not to exceed 66 months) from the date of the last testing. The length of time to complete mitigating activities is related to seasonal access issues during the winter months in Maine, contractor availability, and an inability to make system changes during peak summer months.

NERC Noncompliance ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Mitigation Completion Date
NPCC2019021383	MOD-025-2	R2	Helix Maine Wind Development, LLC	NCR11766	8/2/2017	Present	Self-Report	Expected Completion 10/29/2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On April 18, 2019, Helix Maine Wind Development, LLC (Kibby Wind) submitted a Self-Report stating that as a Generator Owner (GO), it was in noncompliance with MOD-025-2 R2. Kibby Wind failed to provide its Transmission Planner (TP) with verification of its reactive power capability within 90 days of the test completion. Kibby Wind became a new NERC registered entity on August 2, 2017 upon purchase from its previous owner. As part of the sale process, the previous owner provided the facility's compliance documentation for the NERC Reliability Standards including MOD-025-2. During an internal review, it was identified that Kibby Wind did not have appropriate documentation for MOD-025-2 R2 for the performance of the reactive power test results and submittal of the test results to the New England ISO Transmission Planner within 90 days of test completion. From the documentation, it was determined that the reactive power test was attempted on June 28, 2016, but the test was terminated by the New England–ISO because the unit was operating outside of its voltage schedule. The previous owner indicated that they obtained and then submitted operational data for the reactive test in November 2016 but Kibby Wind was unable to find evidence that the previous owner submitted the test data to the TP. Kibby Wind contacted both the New England ISO and the previous owner to determine if the test data had been submitted as required, however, no evidence of provision to the TP could be found. This noncompliance started on August 2, 2017, when Kibby Wind's GO function became effective and will end by October 29, 2019, when the test results will be submitted to the TP. The root cause of this noncompliance was a lack of retention of proper compliance records by the previous owner and a seemingly lack of a clear understanding of the requirement by the previous owner to submit the test results to the TP within 90 days of completion of the staged test.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk due to this noncompliance is by failing to provide the test results to the TP within 90 days, the TP could have inaccurate information about the generating units when developing planning models to assess BPS reliability. However, Kibby Wind is a 132 MVA facility and its applicable facilities consist of 44 wind turbines at 3 MVA each. The facility has had a capacity factor of 27.15% in 2016, 27.70% in 2017, and 25.09% in 2018. The rated capability of the site is 6% of the ISONE typical required Operating Reserve (approximately 2,200 MW). The required testing is scheduled for the end of July 2019. Additionally, because the facility is an intermittent wind generator, its ability to supply reactive power is limited by the environmental conditions at the facility. The MOD-025 standard recognizes this and the requirement in Attachment 1 is to obtain the maximum reactive power lagging output provided at the time of the test. The information supplied to the TP is not necessarily the actual capability of the facility. This limitation is understood by the TP and is worked into their model for distributed wind facilities. No harm is known to have occurred as a result of this noncompliance. NPCC considered Kibby Wind's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Kibby Wind will complete the following mitigation activities on or before October 29, 2019: 1) schedule and complete reactive power testing when 90% of wind turbines can be online; 2) complete MOD-025-2 awareness training for plant personnel; 3) provide completed testing results to TP; and 4) utilize GenSuite Scheduling System to schedule future testing and TP notification reminders within five years (not to exceed 66 months) from the date of the last testing. The length of time to complete mitigating activities is related to seasonal access issues during the winter months in Maine, contractor availability, and an inability to make system changes during peak summer months.

NERC Noncompliance ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Mitigation Completion Date
NPCC2019021388	PRC-024-2	R1	Helix Maine Wind Development, LLC	NCR11766	8/2/2017	3/27/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On April 18, 2019, Helix Maine Wind Development, LLC (Kibby Wind) submitted a Self-Report stating that as a Generator Owner (GO), it was in noncompliance with PRC-024-2 R1. Kibby Wind failed to set its protective relaying such that the generator frequency protective relaying does not trip within the "no trip zone." Kibby Wind became a NERC registered entity on August 2, 2017 upon purchase from its previous owner. As part of the sale process, the previous owner provided the facility's compliance documentation for the NERC Reliability Standards including PRC-024-2. Kibby Wind reviewed the information and decided to retain a third-party contractor to evaluate and confirm that the Frequency and Voltage Protective Relay settings met the requirements in Attachment 1 of PRC-024-2. The evaluation determined that one overfrequency relay setting that trips within the "no trip zone" was identified as noncompliant with the PRC-024-2 standard. Kibby Wind contacted the New England ISO on February 13, 2018 and notified it that a relay needed to be recalibrated to be compliant with the standard. Due to weather conditions at the facility which prevented immediate calibration, the need to perform the calibration was inadvertently and temporarily lost. The following year (February 11, 2019), during an annual review of its programs and PRC-024-2 requirements, Kibby Wind identified that it could not find documentation demonstrating that the relays requiring recalibration had been performed. On March 19, 2019, after confirming the relays had not been calibrated, Kibby Wind notified NE-ISO of the status of the relays and that the relays would be recalibrated to bring them back into compliance. The relay was recalibrated on March 27, 2019. This noncompliance has two main causes. The first issue occurred during the sale process when Kibby Wind reviewed the facility's compliance status with the NERC Reliability Standards. The initial transition review was not detailed enough to identify there were potential compliance issues with PRC-024. The second cause was because there was not an an adequate tracking system to ensure that the relay would be recalibrated in a timely matter when weather conditions improved. This noncompliance started on August 2, 2017, when Kibby Wind's GO function became effective. The noncompliance ended on March 27, 2019 when the frequency relay was recalibrated.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Noncompliance with PRC-024-2 R1 could result in trips that would otherwise not occur and capacity loss during a system voltage excursion event, which would further stress the system during a contingency. However, Kibby Wind is a 132 MVA facility and its applicable facilities consist of 44 wind turbines at 3 MVA each. The facility has had a capacity factor of 27.15% in 2016, 27.70% in 2017, and 25.09% in 2018. The rated capability of the site is 6% of the ISONE typical required Operating Reserve (approximately 2,200 MW). ISONE would be able to obtain that amount of replacement operating reserve. This noncompliance consisted of incorrect frequency protective relaying settings that would trip within the "No Trip zone" of Attachment 1. To achieve compliance, Kibby Wind implemented changes to the tripping points of the Overfrequency relay, as summarized below: Relay / Protective Element / Noncompliant Setting (Existing Setting) / Compliant Setting (Implemented) K1-451 / Overfrequency (81O) / 61.2Hz@0.2 sec. / 61.2Hz@66.67 sec. K1-451 / Overfrequency (81O) / 60.5Hz@10 sec. / 60.6Hz@608.33 sec. No harm is known to have occurred as a result of this noncompliance. NPCC considered Kibby Wind's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Kibby Wind: 1) updated the required overfrequency setting on the relay; 2) created GenSuite Scheduling System tasks and reminders to evaluate and verify relay settings; and 3) completed PRC-024-2 awareness training with plant personnel.

NERC Noncompliance ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Mitigation Completion Date
NPCC2019021384	PRC-024-2	R2	Helix Maine Wind Development, LLC	NCR11766	8/2/2017	3/27/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On April 18, 2019, Helix Maine Wind Development, LLC (Kibby Wind) submitted a Self-Report stating that as a Generator Owner (GO), it was in noncompliance with PRC-024-2 R2. Kibby Wind failed to set its protective relaying such that the generator voltage protective relaying does not trip within the "no trip zone." Kibby Wind became a new NERC registered entity on August 2, 2017 upon purchase from the previous owner. As part of the sale process, the previous owner provided the facility's compliance documentation for the NERC Reliability Standards including PRC-024-2. Kibby Wind reviewed the previous owner's documentation and then retained a third-party contractor to evaluate and confirm that the Voltage Protective Relay settings met the requirements in Attachment 2 of PRC-024-2. The evaluation was completed in January 2018 and it identified that some relays that trip within the "no trip zone" were noncompliant with PRC-024-2 R2. There were two relays that required updated voltage settings. One of them needed the undervoltage element (27) updated and the other needed the overvoltage element (59) updated. Kibby Wind contacted the New England ISO on February 13, 2018 and notified it of the relays that needed settings changes to be compliant with PRC-024-2. Due to weather conditions at the facility which prevented immediate adjustment, the need to perform the adjustment was inadvertently and temporarily lost. The following year (February 11, 2019), during an annual review of its programs and PRC-024-2 requirements, Kibby Wind identified that it could not find documentation demonstrating that the relays requiring settings changes had been performed. On March 19, 2019, after confirming the relays had not been changed, Kibby Wind notified NE-ISO of the status of the relays and that the relays would be adjusted to bring them back into compliance. On March 27, 2019, the relays were changed bringing them back into compliance. The root cause of this noncompliance was a lack of review of compliance documentation around the time of the sale. This initial transition review was not detailed enough to identify there were potential compliance issues with PRC-024-2. A contributing factor to the length of the noncompliance was there was not an adequate tracking system to ensure that the relays would be adjustment in a timely matter when weather conditions improved. This noncompliance started on August 2, 2017, when the entity's GO function became effective. The noncompliance ended on March 27, 2019, when the relays that required voltage settings changes were adjusted.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Noncompliance with PRC-024-2 R2 could result in trips that would otherwise not occur and capacity loss during a system voltage excursion event, which would further stress the system during a contingency. However, Kibby Wind is a 132 MVA facility and its applicable facilities consist of 44 wind turbines at 3 MVA each. The facility has had a capacity factor of 27.15% in 2016, 27.70% in 2017, and 25.09% in 2018. The rated capability of the site is 6% of the ISONE typical required Operating Reserve (approximately 2,200 MW). ISONE would be able to obtain that amount of replacement operating reserve. This noncompliance consisted of incorrect voltage protective relaying settings that would trip within the "No Trip zone" of Attachment 2. To achieve compliance, Kibby Wind implemented changes to the tripping points of the undervoltage element (27) updated and the overvoltage element (59), as summarized below: Relay / Protective Element / Noncompliant Setting (Existing Setting) / Compliant Setting (Implemented) L1-351S / Undervoltage (27) / 50.25V@2 sec. / 41.0V@2.67 sec. K1-451 / Undervoltage (27) / 59.4V@1 sec. / 39.0V@2.67 sec. K1-451 / Overvoltage (59) / 82.5V@ Instaneous / 81.0V@ Instantaneous K1-451 / Overvoltage (59) / 75.9V@0.1 sec. / 74.0V@1 sec. No harm is known to have occurred as a result of this noncompliance. NPCC considered Kibby Wind's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Kibby Wind: 1) updated the required frequency relay; 2) created GenSuite Scheduling System tasks and reminders to evaluate and verify relay settings; and 3) completed PRC-024-2 awareness training with plant personnel.

NERC Noncompliance ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Mitigation Completion Date
NPCC2019021405	PRC-019-2	R1	Marco DM Holdings, LLC	NCR11793	7/1/2018	6/30/2019	Self-Report	6/30/2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On April 25, 2019, Marco DM Holdings, LLC (the entity) submitted a Self-Report stating that as a Generator Owner (GO), it was in noncompliance with PRC-019-2 R1. The entity discovered that it failed to coordinate the voltage regulating system controls with the capabilities and settings of Protection Systems devices. Specifically, the entity failed to complete a Voltage Regulating System Coordination Study after an annual assessment of NERC Reliability Standards. PRC-019-2 R1 is a phased in implementation Standard requiring the entity to perform analyses to verify voltage regulating controls and system protection coordination of at least 60% of its units by July 1, 2017 and 80% by July 1, 2018. The previous owners owned a large number of Facilities and were within an acceptable percentage of completion within the implementation plan at the time of the sale. On September 23, 2017, Marco DM Holdings purchased the combined cycle site. As a result, both generating units at the site were required to have performed the verification by the next implementation plan milestone, July 1, 2018, to remain in compliance. The entity failed to verify both of its generating Facilities by July 1, 2018. The noncompliance started on July 1, 2018, when the entity failed to verify 80% of its generating facilities voltage regulating controls and system protection. The noncompliance will end on June 30, 2019, when the entity makes the necessary changes based on the coordination. This noncompliance resulted from a lack of sufficient documentation provided by the previous owner and a general lack of awareness by the new ownership during the transition. The issue was compounded by failing to establish reminders in the new owner's maintenance and compliance tracking systems.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Specifically, failure to verify that the voltage regulating system controls were properly coordinated with its Protection Systems could lead to a generator tripping for a system event that should not have caused the generator to trip or could fail to trip before equipment damage occurred. However, the site consists of a single 157 MW combine-cycle natural gas-fired facility. The site has had a capacity factor of 6.7% in 2016, 17% in 2017, and 18.5% in 2018. The rated capability of the facility is about 7.1% of the ISO-New England (ISONE) typical required Operating Reserve (approximately 2,200 MW). ISONE would be able to obtain that amount of replacement operating reserve. Additionally, the noncompliance was discovered through an annual assessment that operated as a detective control as part of the entity's internal compliance program. The required coordination was completed within six weeks of its discovery. No harm is known to have occurred as a result of this noncompliance. NPCC considered the entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity will complete the following mitigation activities on or before June 30, 2019: 1) complete the required voltage regulating system coordination study; 2) create reminders in the maintenance tracking system and the compliance tracking system of both plants to prevent recurrence; and 3) implement the changes based on the recommendations of the coordination study.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020737	PRC-024-2	R1	American Municipal Power Inc.	NCR00683	7/1/2018	11/12/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 14, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R1. While preparing for an upcoming Compliance Audit, the entity discovered it was not in compliance with PRC-024 because the tests for two facilities, which were required to meet the 80% implementation requirement, were not completed correctly. The two facilities are AMP Fremont Energy Center (AFEC) and Hamilton JV2. As the entity has a total of seven generation facilities, the entity only completed testing on approximately 70% of its facilities by July 1, 2018 and not the required 80%. AFEC has two natural gas turbines (224 MVA each) and one steam turbine (422 MVA) for a total of 870 MVA with an average capacity factor of approximately 53% during the noncompliance. Hamilton JV2 is a peaking unit with a net rating of 32 MVA and an average capacity factor of less than 1% during the noncompliance. The entity determined the cause of the noncompliance to be an error in the settings adjustment provided in the engineering analysis of the existing settings for the two facilities at issue as a result of a misunderstanding of the settings and the scope of the PRC-024 Standard by an engineer that is no longer employed by the entity. This noncompliance involves the management practices of workforce management and verification as the engineer did not understand the scope of the PRC-024 Standard and the entity did not verify that the engineer completed the settings adjustments correctly. The engineer's misunderstanding is a root cause of this noncompliance. This noncompliance started on July 1, 2018, when the entity was required to comply with PRC-024-2 R1 by having completed testing on 80% of its applicable Facilities and ended on November 12, 2018, when the entity completed its Mitigation Plan by making the settings adjustments at Hamilton JV2.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because of the short duration of this noncompliance (approximately three months). Additionally, the two facilities at issue in this noncompliance have not experienced any trips due to the applicable settings either during the implementation period or prior to the existence of the Standard. The existing settings allowed for an appropriate level of ride-through capability, and the standard obligations outlined in PRC-024-2 will simply enhance the ride-through capability of the Facilities. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity made adjustment to the settings for Hamilton JV2, which resulted in greater than 80% of the Facilities being completed, thereby meeting the implementation plan for PRC-024. The entity also revised its compliance program to include reviews of the compliance programs by multiple responsible staff (rather than a single individual) to ensure strong compliance with PRC-024. Additionally, the entity hired a third-party NERC compliance contractor to conduct a gap analysis on the compliance program and to develop a robust compliance program. (In the summer of 2018, the entity hired a NERC consultant to conduct in person training with the plant managers. The entity determined that the training was well received and will conduct similar training no less than once every two years to encourage a high level of awareness among the plant managers of the NERC Standards and Requirements. Additionally, the Director of Reliability Standards Compliance will conduct training, or supervise the training from a contracted third party, for all newly hired Generation Operations managers within two months of employment with the entity. This initial and periodic training will ensure that if there are any personnel changes, new personnel will be timely apprised of the NERC Standards and Requirements, any upcoming changes, and will understand the importance of reviewing any relay settings prior to making any changes.) The heightened level of awareness of the importance of all relay settings will ensure that any future relay settings changes will undergo a thorough review to ensure the settings are in conformance with the various Standards and regulations and are appropriately coordinated. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020738	PRC-024-2	R2	American Municipal Power Inc.	NCR00683	7/1/2018	11/12/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 14, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R2. While preparing for an upcoming Compliance Audit, the entity discovered that two of its generation facilities were not in compliance with PRC-024. The two facilities are AMP Fremont Energy Center (AFEC) and Hamilton JV2. As the entity has a total of seven generation facilities, the entity only completed testing on approximately 70% of its facilities by July 1, 2018 and not the required 80%. AFEC has two natural gas turbines (224 MVA each) and one steam turbine (422 MVA) for a total of 870 MVA with an average capacity factor of approximately 53% during the noncompliance. Hamilton JV2 is a peaking unit with a net rating of 32 MVA and an average capacity factor of less than 1% during the noncompliance. The entity determined the cause of the noncompliance to be an error in the settings adjustment provided in the engineering analysis of the existing settings as a result of a misunderstanding of the settings and the scope of the PRC-024 Standard by an engineer that is no longer employed by the entity. This noncompliance involves the management practices of workforce management and verification as the engineer did not understand the scope of the PRC-024 Standard and the entity did not verify that the engineer completed the settings adjustments correctly. The engineer's misunderstanding is a root cause of this noncompliance. This noncompliance started on July 1, 2018, when the entity was required to comply with PRC-024-2 R2 by having completed testing on 80% of its applicable Facilities and ended on November 12, 2018, when the entity completed its Mitigation Plan by making the settings adjustments at Hamilton JV2.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because of the short duration of this noncompliance (approximately three months). Additionally, the two facilities at issue in this noncompliance have not experienced any trips due to the applicable settings either during the implementation period or prior to the existence of the Standard. The existing settings allowed for an appropriate level of ride-through capability, and the standard obligations outlined in PRC-024-2 will simply enhance the ride-through capability of the Facilities. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity made adjustment to the settings for Hamilton JV2, which will result in greater than 80% of the Facilities being completed, thereby meeting the implementation plan PRC-024. The entity also revised its compliance program to include reviews of the compliance programs by multiple responsible staff (rather than a single individual) to ensure strong compliance with PRC-024. Additionally, the entity hired a third-party NERC compliance contractor to conduct a gap analysis on the compliance program and to develop a robust compliance program. (In the summer of 2018, the entity hired a NERC consultant to conduct in person training with the plant managers. The entity determined that the training was well received and will conduct similar training no less than once every two years to encourage a high level of awareness among the plant managers of the NERC Standards and Requirements. Additionally, The Director of Reliability Standards Compliance will conduct training, or supervise the training from a contracted third party, for all newly hired Generation Operations managers within two months of employment with the entity. This initial and periodic training will ensure that if there are any personnel changes, new personnel will be timely apprised of the NERC Standards and Requirements, any upcoming changes, and will understand the importance of reviewing any relay settings prior to making any changes.) The heightened level of awareness of the importance of all relay settings will ensure that any future relay settings changes will undergo a thorough review to ensure the settings are in conformance with the various Standards and regulations and are appropriately coordinated. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020616	MOD-026-1	R6	Indianapolis Power & Light Company	NCR00798	9/7/2016	9/7/2016	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On October 19, 2018, the entity submitted a Self-Report stating that, as a Transmission Planner, it was in noncompliance with MOD-026-1 R6. During a mock audit conducted in September 2018, the entity discovered that it failed to meet the 90-day timeframe for providing a written response to its Transmission Planner (TP). On June 8, 2016, the entity's Generator Owner (GO) provided MOD-026-1 test and verification reports for Petersburg Units #1, #2, #3, and #4. However, the entity's TP did not respond in writing until Wednesday, September 7, 2016 (one day late) pursuant to MOD-26-1 R6. The root cause of this noncompliance was the entity's out-of-date tracking processes to ensure the written response was submitted on time. This root cause involves the management practice of work management, which includes establishing a work management process for grid reliability related activities. This noncompliance started on September 7, 2016, when the entity was required to provide the written response and ended later that same day when the entity submitted the written response.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by a TP not providing the written response to the GO within 90 days is that it could impede the verification of models and data for generator excitation control system or plant volt/var control functions. This risk was mitigated in this case by the fact that the entity provided the written response only one day late, which minimized the likelihood of any adverse impact. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity created a tracking spreadsheet to log MOD-026 activities and calculated correspondence date deadlines.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020464	EOP-006-2	R5	PJM Interconnection, LLC	NCR00879	6/3/2017	1/20/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On September 19, 2018, the entity submitted a Self-Report stating that, as a Reliability Coordinator (RC), it was in noncompliance with EOP-006-2 R5. On May 31, 2017, Virginia Electric and Power Company dba Dominion Energy Virginia (VEPCO) cut a new bus into an existing blackstart path. VEPCO had previously submitted an updated restoration plan to the entity in accordance with EOP-005 on May 3, 2017. On May 22, 2017, the entity approved the updated restoration plan as adequate and allowed the cut-in to occur per the entity's processes. However, during an internal review in January, 2018, VEPCO's compliance staff determined that the information that it provided to the entity was incomplete. VEPCO had failed to fully update the restoration plan prior to submitting it to the entity, as it did not include the actual switching steps or the new switching diagram snapshots. Without this information, the entity could not have determined compatibility with its restoration plan and other Transmission Operators' restoration plans. The entity failed to adequately review the submitted restoration plan prior to approving it on May 22, 2017. The root cause of this noncompliance was a lack of sufficient review and verification controls. While there was an established process for the submission and approval/disapproval of restoration plans, VEPCO failed to verify that the updated restoration plan contained all necessary information prior to submitting it per the entity's processes, and the entity failed to adequately review the updated restoration plan prior to approving it. This noncompliance implicates the management practices of verification and workforce management. Verification was involved because the entity failed to verify that the restoration plan contained the necessary content. Workforce management was involved because human factor issues, such as the oversights at issue in this matter, can oftentimes be minimized through the implementation of adequate controls. This noncompliance started on June 3, 2017, when the entity did not conduct an adequate review of VEPCO's submitted restoration plan within thirty (30) calendar days of receipt and ended on January 20, 2018, when the restoration plan was updated, corrected, and approved.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk of this noncompliance is having diagrams and switching steps that are incompatible with the latest system configuration, which could cause errors or delays during system restoration. The risk was mitigated because the VEPCO system operators were well acquainted with the new equipment, and the changes to the switching steps that were required to energize the cranking path were obvious and elementary. Further, if system restoration had been required, the entity has developed (and drilled) a process to monitor and coordinate restoration, which includes constant communication with members and neighboring RCs. This reduced the risk because the entity would have been working closely with VEPCO during restoration. The incomplete restoration plan issue would likely have been quickly identified, communicated, and resolved because of VEPCO's familiarity with the new equipment and the entity's constant communication with members during restoration. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity ensured that VEPCO implemented remedial steps to mitigate a similar occurrence. VEPCO's mitigation included the following steps. 1) added all lines and substations that could affect the System Restoration Plan to its outage system, and an e-mail is now generated and sent to the Restoration Plan subject matter expert (SME) whenever there is work scheduled for an affected line or substation; 2) require a Restoration Plan SME to review all new construction one lines generated to determine if future work will impact the Restoration Plan; and 3) added a "Review to the Restoration Plan" tab to their Energizing Procedure Checklist. This provides an additional barrier and end of process safeguard to prevent energizing equipment that would impact the need to revise the current Restoration Plan. In addition to ensuring that VEPCO implemented remedial steps, the entity completed the following mitigation: 1) added Attachment G to the eDART request, which is a form that a Transmission Owner (TO) fills out to describe coordination (internal and external) around restoration efforts. Comments will be required for any question where "Not Included" has been selected. This added control is a way to validate and provide a reason as to why the information was not included or not applicable to a restoration plan; 2) added an explanation field to the eDART tickets. The entity flags all cut-in eDART tickets to be reviewed by the TO to determine if the work will require a change to the restoration plans. If "no update needed" is selected by the TO, an added control will require the user to include an explanation on why "no update is needed." An author will not be able to proceed with the ticket until he/she enters the reason; and 3) updated the process for cut-in tickets. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020562	EOP-011-1	R3	PJM Interconnection, LLC	NCR00879	7/23/2018	7/23/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On October 15, 2018, the entity submitted a Self-Report stating that, as a Reliability Coordinator, it was in noncompliance with EOP-011-1 R3. Pursuant to EOP-011-1 R3, within 30 calendar days of receipt, the entity is required to review an Operating Plan submitted by a Transmission Operator (TOP) and notify the TOP of the results of its review. On June 22, 2018, ITC Interconnection, LLC ("ITCI") submitted its Operating Plan to mitigate emergencies to the entity. A few days later, on June 25, 2018, ITCI sent an e-mail to the entity indicating that an attachment to the Operating Plan was submitted in error. The removal of the attachment did not alter the Operating Plan in a substantive way. On July 23, 2018 (i.e., 31 days after it submitted the Operating Plan), ITCI sent an e-mail to the entity inquiring as to the status of the entity's review of the Operating Plan. The entity reviewed the Operating Plan on the same day and responded to the e-mail with the results of its review. In summary, the entity completed its review of the Operating Plan and notified ITCI of the results of its review one day late in violation of EOP-011-1 R3. The root cause of this noncompliance was the lack of adequate procedures and controls to track and monitor deadlines to review Operating Plans and communicate the results to TOPs and Balancing Authorities (BAs). At the time of this noncompliance, the procedure was largely manual, and the receipt of the e-mail regarding the errant attachment resulted in the entity ignoring the original e-mail and Operating Plan until ITCI sent a follow-up e-mail on July 23, 2018. This noncompliance implicates the management practice of workforce management. Oftentimes, the development and implementation of effective processes, procedures, and controls will minimize human factor issues, such as overlooking the Operating Plan submitted on June 22, 2018, due to a subsequent e-mail regarding an errant attachment. This noncompliance started on July 23, 2018, after the deadline to review ITCI's Operating Plan and notify ITCI of the results of the review passed and ended later on July 23, 2018, when the entity completed the review and notified ITCI of the results.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. A failure to review Operating Plans submitted by TOPs and BAs in a timely manner could lead to insufficient coordination of Operating Plans, which could adversely affect Wide Area reliability. In this case, the risk was mitigated by the following facts. First, the review and notification of the results of the review were completed only one day after the deadline set forth in EOP-011-1 R3. Second, the Operating Plan submitted on June 22, 2018, was largely identical to the prior version of the Operating Plan that was submitted and reviewed, thus further reducing the risk. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) developed a SharePoint site to process EOP-011-1 Operating Plan review request e-mails. Once the request is received by the entity, the SharePoint site will initiate a workflow, which sends reminders to a designated team of individuals until the original request e-mail is acknowledged and responded to. The manager of entity dispatch will be responsible for ensuring responses are sent to the requesting entity within the timeframe set forth in EOP-011-1; and 2) implemented the SharePoint site and trained designated teams responsible for using it.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2019021296	FAC-008-3	R8.1	CenterPoint Energy Houston Electric, LLC (CNP) (the "Entity")	NCR04028	05/14/2018	01/08/2019	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On April 1, 2019, the Entity submitted a Self-Log stating that, as a Transmission Owner (TO), it was in noncompliance with FAC-008-3 R8.1. Specifically, the Entity failed to provide Facility Ratings to its Reliability Coordinator (RC) for three tie lines prior to energization of the lines. The first instance of noncompliance was discovered on December 11, 2018, during the investigation of missing telemetry for a 138-kV tie-line that had been energized the day before. During the investigation, the Entity discovered that the line was energized prior to submitting Facility Ratings to its RC. In this instance, the tie line was connected to a substation owned by another registered entity and when the other registered entity built a new substation, the line termination was changed to the new substation. The rating for the portion of the Facility owned by the Entity was 360 MVA and remained 360 MVA following the change; however, the Entity did not update its RC with the new Facility Rating following the neighboring utility's change to the Facility. The Entity owns the breakers and switches at one substation and the 0.46 miles of conductor, that comprises the line. To end the noncompliance, the Entity submitted facility ratings for the new line configuration to its RC on December 12, 2018. The second instance of noncompliance was discovered when the Entity conducted a review of its remaining tie line ratings following discovery of the first instance. The Entity discovered two additional 138-kV tie lines that were energized on May 14, 2014, prior to the submittal of Facility Ratings to its RC. A neighboring utility owns both lines, and the Entity owns the breakers, disconnects, and line switches that feed the lines at one substation. To end the noncompliance, on January 8, 2019, the Entity submitted Facility Ratings to its RC for the equipment it owns for the two lines. The root cause for this noncompliance was an insufficient process for tracking multiple phases of projects initiated by neighboring entities. This noncompliance started on May 14, 2018, when two of the transmission lines were energized prior to the Entity submitting Facility Ratings for the portion of the lines owned by the Entity, and ended on January 8, 2019, when the Entity submitted to its RC the Facility Ratings for the portions of the two Facilities owned by the Entity.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. For the first instance, the Facility Rating for the portion of the facility owned by the Entity did not change, and the Facility Rating is nominally different than the portion owned by the neighboring utility. The Entity's equipment in the first instance is not the Most Limiting Series Element during a contingency when a two-hour rating is the System Operating Limit (SOL). For the time period at issue the actual maximum loading on the line was 25% of the overall rating. Additionally, ratings for the previous Facility configuration already existed in the RC's operations model. For the second instance, the Entity's MLSE at the substation at issue is rated at 838 MVA, well above the neighboring utility's Facility rating of 212 MVA for the two lines. Additionally, the actual maximum loading for the two lines was 54 MVA and 51 MVA, well below the 838 MVA rating for the Entity's equipment. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, the Entity: 1) submitted the Facility Ratings for its portion of the Facilities at issue to its RC; 2) modified and documented existing processes for entering and tracking multiple phases of projects initiated by a neighboring entity in the tool used for weekly monitoring and tracking of project phases, including the need to submit facility ratings to the RC; and 3) provided the updated process to affected staff. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018018925	PRC-019-2	R1	Chamon Power LLC (ChamonPower)	NCR11807	10/24/2017	1/8/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 29, 2017, ChamonPower submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with PRC-019-2. Specifically, ChamonPower failed to coordinate the voltage regulating system controls with the applicable equipment capabilities and settings of the applicable Protection System Devices and functions. ChamonPower initially registered with NERC on October 24, 2017, without evidence that it had coordinated its voltage regulating system controls with the applicable equipment capabilities and settings of the applicable Protection System Devices and functions, in accordance with PRC-019-2, R1. ChamonPower conducted a review of its compliance obligations, and on December 8, 2017, the noncompliance was discovered. On January 8, 2018, ChamonPower performed the required PRC-019-2 coordination study. The root cause for this noncompliance was that ChamonPower did not assign sufficient resources and adequately prepare for full compliance with the NERC Standards. This noncompliance began on October 24, 2017, when ChamonPower was initially registered with NERC without evidence that it had coordinated its voltage regulating system controls with the applicable equipment capabilities and settings of the applicable Protection System Devices and functions, in accordance with PRC-019-2, R1. The noncompliance ended on January 8, 2018, when ChamonPower performed a PRC-019-2 coordination study and provided ChamonPower with the required evidence.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. In this instance, ChamonPower lacked the evidence required by the standard to show that it had coordinated its applicable equipment capabilities and settings of the applicable Protection System Devices and functions. However, it was determined during the coordination study that no actual settings changes were necessary for compliance with PRC-019-2. Additionally, ChamonPower did not trip off-line during the period of the noncompliance; the Facility reached full compliance within 31 days of discovering the noncompliance; and the noncompliance lasted 5 months and 3 days. No harm is known to have occurred. Texas RE considered ChamonPower's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, ChamonPower: 1) completed the required coordination study within 31 days of discovering the noncompliance thereby limiting the noncompliance to 5 months and 3 days; 2) effectuated a plant procedures to implement PRC-019-2; and 3) created automatic reminders to annually review the PRC-019-2 procedure and update it as necessary, and to notify ChamonPower personnel one year prior to the next PRC-019-2 deadline. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018018926	PRC-024-2	R1	Chamon Power LLC (ChamonPower)	NCR11807	10/24/2017	3/27/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 29, 2017, ChamonPower submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with PRC-024-2. Specifically, it failed to set its frequency protective relaying such that it would not trip the generating units within the "no trip zone" of PRC-024 Attachment 1, in accordance with PRC-024-2 R1. ChamonPower initially registered with NERC on October 24, 2017, with generator frequency protective relaying activated to trip its applicable generating units within the "no trip zone" of PRC-024-2 Attachment 1. ChamonPower's Asset Manager conducted a review of its compliance obligations, and on December 8, 2017, the noncompliance was discovered. On January 5, 2018, a second contractor for ChamonPower performed a PRC-024-2 coordination study and determined the specific frequency settings upgrades necessary for compliance. On March 27, 2018, ChamonPower completed the required settings upgrades ending ChamonPower's noncompliance with PRC-024-2 R1. The root cause for this noncompliance was that ChamonPower did not assign sufficient resources and adequately prepare for full compliance with the NERC Standards. This noncompliance began on October 24, 2017, when ChamonPower was initially registered with NERC with its generator frequency protective relaying activated to trip its applicable generating units within the "no trip zone." The noncompliance ended on March 27, 2018, when ChamonPower performed the necessary settings upgrades such that the generator's frequency protective relaying would no longer trip within the "no trip zone."
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk posed by this instance of noncompliance is the tripping of a generating unit within a no trip zone. Several factors mitigated the risk posed by this issue. First, ChamonPower has a relatively small power output. Its nameplate rating is 121 MW; the GO reported that its actual total power output capability is approximately 100MW; and its capacity factor is 4.41%. Second, when ChamonPower operated during the period of noncompliance no trips occurred due to the applicable relay trip settings being within the "no trip zone." No harm is known to have occurred. Texas RE considered ChamonPower's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, ChamonPower: 1) completed the required settings upgrades limiting the period of noncompliance to 5 months, 3 days; 2) created a plant procedure to ensure that generator protective relay settings are reviewed and set such that generating units remain connected during defined frequency excursions; and 3) created annual automatic reminders requiring specific ChamonPower staff to review generator protective relay settings. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017017519	PRC-005-1	R2	City of College Station (COCS)	NCR04032	5/23/2008	12/14/2016	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from March 20, 2017 through May 1, 2017, Texas RE determined that COCS, as a Transmission Owner (TO) and Distribution Provider (DP), was in noncompliance with PRC-005-1 R2. Specifically, COCS did not timely perform certain maintenance and testing activities for 30 Protection System devices within the defined intervals specified in its Protection System Maintenance Program (PSMP). The scope of the noncompliance includes three separate issues. First, at the time of COCS's registration as a TO and DP in 2007, COCS's PSMP specified a 10-calendar-year maintenance interval for testing its protective relays, which included testing control circuitry by requiring that protective relays be "test tripped." During a Compliance Audit conducted on May 21 and May 22, 2008, the Compliance Audit reviewed COCS's PSMP and did not identify any instances of noncompliance regarding PRC-005-1 R1 and R2. However, on December 12, 2008, COCS adopted a new PSMP that specified a 5-calendar-year interval for testing almost all of COCS's protective relays and for performing "test tripping" for COCS's control circuitry devices. When the revised PSMP became effective, five protective relays had not been tested within the previous five calendar years, and therefore were not compliant with the new PSMP. Second, during 2012 through 2016, COCS failed to timely perform required maintenance activities for eight control circuitry devices and five protective relays. Finally, during the 2017 Compliance Audit, COCS was unable to identify testing dates prior to 2016 for seven control circuity devices and five protective relays. In total, 30 Protection System devices, comprising 13 protective relays and 17 control circuitry devices are affected by these issues. Regarding the control circuitry devices, COCS ended the noncompliance on March 10, 2015, by adopting a revised PSMP consistent with the adoption of PRC-005-2 R1. Under COCS's revised process, COCS considers the control circuitry devices at issue to be fully monitored, consistent with PRC-005-2 Table 1-5, meaning that its PSMP no longer requires periodic maintenance activities for those devices. Regarding the protective relays at issue, COCS ended the noncompliance by testing the protective relays at issue during February 2016, through December 2016. The root cause of this issue is that COCS did not have a sufficient process for tracking the completion of maintenance activities and storing relevant evidence. As a result, COCS did not adhere to the maintenance intervals required by its PSMP for several devices, and, for additional devices, COCS was unable to substantiate whether it had adhered to the required maintenance intervals. This noncompliance started on May 23, 2008, which is the first day following the conclusion of the 2008 Compliance Audit, and ended on December 14, 2016, when COCS tested the remaining protective relays at issue.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The risk posed by this issue is that COCS would not be aware that a Protection System device was not functioning as intended. In addition, the duration of the noncompliance was longer than eight years, from May 23, 2008, to December 14, 2016. However, the risk to the reliability of the BPS was reduced by the following factors. First, this issue involved only 30 devices, which represents approximately 14% of COCS's total number of Protection System devices. These 30 devices comprised 13 of COCS's 100 protective relays and 17 of COCS's 31 control circuitry devices. In addition, none of COCS's underfrequency load shedding devices were affected by the noncompliance. Second, COCS is a small entity that has limited impact on other portions of the BPS during normal operations. In particular, COCS operates approximately 20 miles of 138-kV transmission lines, and is not directly interconnected with any active generating units. During normal operations, COCS's transmission lines serve limited through-flow to other entities, with means it is likely that only load served directly by COCS would be affected if COCS's transmission lines were removed from service. No harm is known to have occurred. Texas RE considered COCS's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, COCS: 1) performed the required maintenance activities for the remaining protective relays at issue; 2) implemented a new software database for storing and maintaining testing documentation; 3) revised its PSMP to reflect the use of the new software database; and 4) conducted training regarding the new software database. Texas RE has verified the completion of all mitigation activities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017017803	FAC-008-3	R6	CPS Energy (CPS Energy1)	NCR04037	2/28/2014	5/18/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from May 15, 2017, through June 26, 2017, Texas RE determined that CPS Energy1, as a Transmission Owner (TO), was in noncompliance with FAC-008-3 R6. Specifically, CPS Energy1 did not have Facility Ratings for its solely and jointly owned Facilities that were consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings. During the Compliance Audit, Texas RE determined that for two transmission lines CPS Energy1 did not record accurate Facility Ratings in its Facility Ratings database. In the first instance, for one 138-kV transmission line, during an upgrade project the initial design of the upgrade project allowed for a 554 MVA rating. Following project completion on October 8, 2015, data forms indicated that the final project design allowed for a 478 MVA rating; however, the Facility Ratings database was not updated until March 30, 2017. In the second instance, for one 345-kV jointly-owned transmission line, CPS Energy1 owns a portion of the line but does not own or operate either endpoint. The Facility Rating that was recorded reflected the portion of the line owned by CPS Energy1 and did not take into account the MLSE for the non-CPS Energy1-owned portions of the Facility. CPS Energy1 revised the Facility Ratings data in its Facility Ratings database from 1104 MVA to 1011 MVA to address the MLSE for the entire Facility. The root cause of this noncompliance was an insufficient process for developing and recording Facility Ratings for jointly-owned Facilities. To address the first instance, CPS Energy1 implemented a process to have two separate transmission planners enter information for new or modified equipment and verify that the information from the form matches what was entered into the database. Additionally, CPS Energy1 implemented a process to check three times annually that information in its facility ratings database is consistent with the data sent to ERCOT. To address the second instance, CPS Energy1 implemented a process to address coordinating with affected neighboring TOs while developing schedules to meet Facility Ratings for Jointly Owned Facilities. This noncompliance started on February 28, 2017, the day following Texas RE's previous Compliance Audit of CPS Energy1, and ended on May 18, 2017, when CPS Energy 1 properly calculated the Facility Ratings at issue based on each transmission line's MLSE.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, historical data for the 138-kV transmission line for the time period at issue indicated that the loading of the line did not exceed 128 MVA. Additionally, a contingency analysis performed during the 2015-2015 planning cycles indicated that, under contingency, the loading of the line did not exceed 211 MVA (44% of 478 MVA) through 2020. Second, for the 138-kV transmission line, the CPS Energy1 and ERCOT operations models had the accurate, lower rating of 478 MVA; therefore, this issue was limited to an incorrect Facility Rating in the CPS Energy1 internal Facility Ratings database which is a stand-alone database with no connectivity to other systems and the data is not directly reflected in the ERCOT models. Additionally CPS Energy1's system operations personnel do not have access to the Facility Ratings database. Third, for the 345-kV jointly-owned transmission line, data obtained from the other owners indicated that the maximum MVA loading for the line in 2016 was 720 MVA and for 2017 it was 704. Additionally, contingency analysis performed for this line did not indicate any exceedances for the time period at issue. Lastly, this issue impacted approximately 1% (2/191) of CPS Energy1's solely and jointly-owned transmission lines. No harm is known to have occurred. Texas RE considered CPS Energy1's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, CPS Energy1: 1) revised the Facility Ratings for the two transmission lines at issue so that they are consistent with the associated Facility Ratings methodology; 2) combined several Facility Ratings processed into one comprehensive Facility Ratings Guide to address the derivation of Facility Ratings, which respect the Most Limiting Series Element (MLSE); 3) in the Facility Ratings Guide, included a requirement to verify that for new or modified equipment information from the data forms is accurately represented in all databases. The new process document clearly defines what fields are required in data forms for user input into the Facility Rating Database and requires that two separate transmission planners enter and verify the data; 4) in the Facility Ratings Guide, included a requirement to coordinate with affected neighboring TOs while developing schedules to meet Facility Ratings for Jointly Owned Facilities; and 5) implemented an internal policy to establish a tracking document for current and future jointly-owned Facilities, and to annually contact each owner of jointly-owned Facilities to review and confirm facility and equipment ratings. Texas RE has verified the completion of all mitigation activities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017017804	FAC-008-3	R8	CPS Energy (CPS Energy1)	NCR04037	1/7/2015	4/11/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from May 15, 2017, through June 26, 2017, Texas RE determined that CPS Energy1, as a Transmission Owner (TO), was in noncompliance with FAC-008-3 R8. Specifically, CPS Energy1 failed to provide correct Facility Ratings to its associated Reliability Coordinator (RC) for three transmission lines. During the Compliance Audit, Texas RE determined that CPS Energy1 had properly calculated the Facility Rating for the three transmission lines at issue; however, CPS Energy1 did not provide the correct Facility Ratings to the RC. Due to an oversight, the data in one model used to derive line impedance data for transmission lines was updated but the Facility Ratings database was not updated until a later date. As a result, the incorrect Facility Rating was provided to the RC. The root cause of this noncompliance was an insufficient process for entering Facility Ratings data in various database applications. CPS Energy1 lacked clear directions for personnel when updating two separate repositories for Facility Ratings data and inputs. As a result, in this case one employee made changes to conductor data in one model and a different employee conducting an update to the Facility Ratings database was not aware of the change in conductor data and, therefore, did not know that there was a new Facility Rating to be communicated and updated. This issue of noncompliance started on January 1, 2015, when the model used for storing inputs for Facility Ratings was updated for one transmission line at issue, and ended on April 11, 2017, when the corrected Facility Ratings were submitted to the RC for the three transmission lines at issue.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, the difference in ratings was small. The largest difference between incorrect ratings provided to the RC and the correct ratings was 1.1%. Second, the loading on the three transmission lines did not exceed the normal ratings during the time period at issue. Additionally, no trips or outages occurred for the three transmission lines at issue during the time period at issue. Lastly, this issue impacted 1.57% (3/191) of CPS Energy1's solely and jointly-owned transmission lines. No harm is known to have occurred. Texas RE considered CPS Energy1's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, CPS Energy1: 1) submitted the correct Facility Ratings to its RC for the three transmission lines at issue; 2) combined several Facility Ratings processed into one comprehensive Facility Ratings Guide to address the derivation of Facility Ratings, which respect the Most Limiting Series Element (MLSE); 3) included in the Facility Ratings Guide a requirement that the same person enters Facility Ratings data into both Facility Ratings database applications, to avoid introducing data inconsistencies. Additionally, the process now requires that a second person visually inspect and verify the data entered into both Facility Ratings database applications to ensure that the values entered into each database match and are correct; 4) included in the Facility Ratings Guide a process to compare and check that Facility Ratings data submitted to the RC matches the Facility Ratings database three times a year; and 5) implemented a process to compare and check the Facility Ratings with the Facility Ratings to be submitted to the RC, prior to the submittal. Texas RE has verified the completion of all mitigation activities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018871	PRC-005-1.1b	R2	CPS Energy (CPS Energy1) (the “Entity”)	NCR04037	1/1/2017	8/5/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 18, 2017, the Entity submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with PRC-005-1.1b R2. Specifically, the Entity did not have documentation that two protective relays were maintained and tested within the intervals defined in its Protection System Maintenance and Testing Program (PSMP). During a planning review in July 2017 for upcoming system protection maintenance activities planned for 2018, the Entity discovered that two generator step up transformer protective relays had not been tested within the maximum maintenance interval. Pursuant to the Entity’s PSMP, the periodic maintenance and calibration for the protective relays at issue was every 6 calendar years. The previous maintenance and testing was performed in October of 2016 and was due to be completed again by December 31, 2016. However, the required maintenance and testing was not completed until August 5, 2017. The root cause of this noncompliance was an insufficient process to identify NERC classification for Protection System devices while converting to a new Protection System maintenance database. In 2014, the Entity initiated a project to convert the existing Protection System device database program to a new software program. During the conversion, two technicians transferred data manually and the process did not include verification of NERC status for the devices. As a result, the two protective relays at issue were not classified as NERC devices resulting in the noncompliance. This noncompliance started on January 1, 2017, one day following calibration-testing deadline for the protective relays, and ended on August 5, 2017, when the Entity completed the required protective relay testing.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, the devices at issue represent approximately 0.2% (2/1,023) of the total Protection System devices in the Entity’s PSMP. Second, the Entity did not identify any issues s when it performed the required maintenance and testing activities for the protective relays at issue. Third, there is no history of misoperations for the two protective relays at issue. Fourth, operational testing for the devices at issue was conducted in 2010 and 2014 with no issues. Lastly, if the relay operates there is an alarm that is monitored by control room operators. Additionally, the control room operators conduct plant walk downs as part of their normal operating procedures to verify that critical equipment is in service and check for relay flag drops or other local relay indications for operation or misoperation. No harm is known to have occurred. A Settlement Agreement covering a violation of PRC-005-1 R2 for the Entity was filed with FERC under NP12-27-00 on May 30, 2012. On June 29, 2012, FERC issued an order stating it would not engage in further review of the Spreadsheet Notice of Penalty.
Mitigation Activity (affidavit required)	To mitigate this noncompliance, the Entity: 1) completed the required maintenance for the two protective relays at issue; 2) conducted a verification of all protective relays to ensure all relays were identified in the field and properly classified in the new database; and 3) established quarterly reviews to ensure all protective relay maintenance is conducted pursuant to the PSMP. Texas RE has verified the completion of all mitigation activities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017017938	MOD-025-2	R1	Formosa Utility Venture, Ltd. (FUV)	NCR04059	7/1/2017	8/7/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 10, 2017, Formosa Utility Venture, Ltd. (FUV) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with MOD-025-2 R1. In particular, FUV failed to verify the Real Power capability Facility in accordance with MOD-025-2, Attachment 1 by July 1, 2017. FUV was required to verify the Real Power capability of at least 60% of its units prior to July 1, 2017. FUV stated that testing on the applicable units was scheduled to occur on June 26 – 27, 2017, that would have satisfied the 60% requirement of MOD-025-2, but that this testing had to be canceled due to a severe weather event that occurred on June 24, 2017. FUV was unable to reschedule the required testing prior to the July 1, 2017 deadline. FUV completed the required testing and provided the results to its Transmission Planner (TP) on August 7, 2017. The root cause of this noncompliance was FUV's failure to schedule its compliance testing sufficiently in advance of the due date as to account for possible delays to the testing date. This noncompliance started on July 1, 2017, when the 60 percent requirement in the Implementation Plan for MOD-025-2 R1 became mandatory and enforceable, and ended on August 7, 2017, when FUV completed the required testing and provided the results to its TP.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The two FUV units that were the subject of the delayed testing and the basis for the noncompliance passed ERCOT mandated Reactive Power Testing in 2015, for both leading and lagging. During the ERCOT testing these units were required to maintain base load and >=90 percent of the rated MVAR capacity at that MW output for greater than 15 minutes. The length of this noncompliance was limited to 37 days. No harm is known to have occurred. Texas RE considered FUV's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, FUV: 1) completed the Real Power capability verification testing that was due on July 1, 2017, and completed all remaining Real Power capability verification testing due under MOD-025-2 well in advance of remaining deadlines ; and 2) provided verification information to its TP in compliance with MOD-025-2. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017017939	MOD-025-2	R2	Formosa Utility Venture, Ltd. (FUV)	NCR04059	7/1/2017	8/7/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 10, 2017, Formosa Utility Venture, Ltd. (FUV) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with MOD-025-2 R2. In particular, FUV failed to verify the Reactive Power capability Facility in accordance with MOD-025-2, Attachment 1 by July 1, 2017. FUV was required to verify the Reactive Power capability of at least 60% of its units prior to July 1, 2017. FUV stated that testing on the applicable units was scheduled to occur on June 26 – 27, 2017, that would have satisfied the 60% requirement of MOD-025-2, but that this testing had to be canceled due to a severe weather event that occurred on June 24, 2017. FUV was unable to reschedule the required testing prior to the July 1, 2017 deadline. FUV completed the required testing and provided the results to its Transmission Planner (TP) on August 7, 2017. The root cause of this noncompliance was FUV's failure to schedule its compliance testing sufficiently in advance of the due date as to account for possible delays to the testing date. This noncompliance started on July 1, 2017, when the 60 percent requirement in the Implementation Plan for MOD-025-2 R2 became mandatory and enforceable, and ended on August 7, 2017, when FUV completed the required testing and provided the results to its TP.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The two FUV units that were the subject of the delayed testing and the basis for the noncompliance passed ERCOT mandated Reactive Power Testing in 2015, for both leading and lagging. During the ERCOT testing these units were required to maintain base load and >=90 percent of the rated MVAR capacity at that MW output for greater than 15 minutes. No harm is known to have occurred. Texas RE considered FUV's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, FUV: 1) completed the Reactive Power capability verification testing that was due on July 1, 2017, and completed all remaining Reactive Power capability verification testing due under MOD-025-2 well in advance of remaining deadlines ; and 2) provided verification information to its TP in compliance with MOD-025-2. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018154	MOD-025-2	R1	NRG Cedar Bayou Development Co, LLC (CBY-4)	NCR10326	7/1/2016	7/7/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On August 9, 2017, NRG Cedar Bayou Development Co, LLC (CBY-4) submitted the Self-Report to Texas RE stating that, as a Generator Owner (GO), it was in noncompliance with MOD-025-2 R1. In particular, CBY-4 did not verify the Real Power capability of its applicable generating units in accordance with MOD-025-2, Attachment 1 by July 1, 2016. Following review of Regional guidance distributed March 24, 2017, regarding the method for measuring compliance under the Implementation Plan for MOD-025-2, CBY-4 discovered that it failed to verify the Real Power capability of its applicable generating units in accordance with MOD-025-2, Attachment 1 by the July 1, 2016 deadline. CBY-4 verified its Real Power capability on May 25, 2017, and provided its Transmission Planner (TP) with verification on July 7, 2017. The root cause of this noncompliance was a misunderstanding of the Implementation Plan for MOD-025-2 and the appropriate methodology that should be used to calculate the percentage of Facilities for staged implementation. CBY-4 was included as part of the overall NRG fleet in calculating the compliance percentages for the ERCOT interconnection, rather than by individual facility registration. This noncompliance started on July 1, 2016, when MOD-025-2 R1 became mandatory and enforceable, and ended on July 7, 2017, when CBY-4 provided its TP with the required verification.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. First, CBY-4 previously provided Reactive power verifications under substantially similar region-specific output conditions in 2013 and 2015, limiting the scope of the missing verification data that would be incorporated into transmission planning models. Second, CBY-4 has a nameplate capacity of 630 MW and a net dependable capability of 546 MW during the period of the noncompliance. As a result, any errors in the Facility's Real output data would only have a minor impact on planning results. No harm is known to have occurred. Texas RE considered CBY-4's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, CBY-4: 1) verified the Real Power capability of its applicable generating units, and provided its TP with verification; 2) created automatic reminders to notify CBY-4 personnel one year prior to the date on which future required tests are due; and 3) implemented a tracking spreadsheet to indicate MOD-025-2 compliance on a Regional level, and more granular (unit) level. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018155	MOD-025-2	R2	NRG Cedar Bayou Development Co, LLC (CBY-4)	NCR10326	7/1/2016	7/7/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On August 9, 2017, NRG Cedar Bayou Development Co, LLC (CBY-4) submitted the Self-Report to Texas RE stating that, as a Generator Owner (GO), it was in noncompliance with MOD-025-2 R2. In particular, CBY-4 did not verify the Reactive Power capability of its applicable generating units in accordance with MOD-025-2, Attachment 1 by July 1, 2016. Following review of Regional guidance distributed March 24, 2017, regarding the method for measuring compliance under the Implementation Plan for MOD-025-2, CBY-4 discovered that it failed to verify the Reactive Power capability of its applicable generating units in accordance with MOD-025-2, Attachment 1 by the July 1, 2016 deadline. CBY-4 verified its Reactive Power capability on May 25, 2017, and provided its Transmission Planner (TP) with verification on July 7, 2017. The root cause of this noncompliance was a misunderstanding of the Implementation Plan for MOD-025-2 and the appropriate methodology that should be used to calculate the percentage of Facilities for staged implementation. CBY-4 was included as part of the overall NRG fleet in calculating the compliance percentages for the ERCOT interconnection, rather than by individual facility registration. This noncompliance started on July 1, 2016, when MOD-025-2 R2 became mandatory and enforceable, and ended on July 7, 2017, when CBY-4 provided its TP with the required verification.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. First, CBY-4 previously provided Reactive power verifications under substantially similar region-specific output conditions in 2013 and 2015, limiting the scope of the missing verification data that would be incorporated into transmission planning models. Second, CBY-4 has a nameplate capacity of 630 MW and a net dependable capability of 546 MW during the period of the noncompliance. As a result, any errors in the Facility's Reactive output data would only have a minor impact on planning results. No harm is known to have occurred. Texas RE considered CBY-4's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, CBY-4: 1) verified the Reactive Power capability of its applicable generating units, and provided its TP with verification; 2) created automatic reminders to notify CBY-4 personnel one year prior to the date on which future required tests are due; and 3) implemented a tracking spreadsheet to indicate MOD-025-2 compliance on a Regional level, and more granular (unit) level. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017018156	PRC-019-2	R1	NRG Cedar Bayou Development Co, LLC (CBY-4)	NCR10326	7/1/2016	6/26/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On August 9, 2017, NRG Cedar Bayou Development Co, LLC (CBY-4) submitted the Self-Report to Texas RE stating that, as a Generator Owner (GO), it was in noncompliance with PRC-019-2 R1. In particular, CBY-4 did not verify the coordination of its voltage regulating system controls with the equipment capabilities and settings of applicable Protection System devices and functions for its Facility by July 1, 2016 as required. Following review of Regional guidance distributed March 24, 2017, regarding the method for measuring compliance under the Implementation Plan for PRC-019-2, CBY-4 discovered that it failed to verify the coordination of its voltage controls and generation protection devices in accordance with PRC-019-2 R1 by the July 1, 2016 deadline. CBY-4 performed a voltage coordination verification study for its Facility on June 26, 2017. During a Compliance Audit conducted from September 12, 2017, through September 14, 2017, Texas RE reviewed CBY-4's compliance with PRC-019-2. The audit team concluded through a review of the documentation and responses to additional questions that CBY-4 became compliant with PRC-019-2 on June 26, 2017. The root cause of this noncompliance was a misunderstanding of the Implementation Plan for PRC-019-2 and the appropriate methodology that should be used to calculate the percentage of Facilities for staged implementation. CBY-4 was included as part of the overall NRG fleet in calculating the compliance percentages for the ERCOT interconnection, rather than by individual facility registration. This noncompliance started on July 1, 2016, when PRC-019-2 R1 became mandatory and enforceable, and ended on June 26, 2017, when CBY-4 verified the coordination of its voltage and generation protection settings at its Facility.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. When CBY-4 performed the required voltage and generation protection verifications through a coordination study, the study confirmed that no changes were required to its voltage controls and generation protection settings. Also, no unit trips occurred due to inadequate coordination during the period of noncompliance. No harm is known to have occurred. Texas RE considered CBY-4's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, CBY-4: 1) completed the required coordination study; 2) created automatic reminders to notify CBY-4 personnel one year prior to the date on which future required tests are due; and 3) implemented tracking spreadsheets that indicate PRC-019-2 compliance on a Regional level, and on a more granular (unit) level. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017017826	PRC-005-1.1b	R2	Texas Municipal Power Agency (TMPA1)	NCR11456	3/25/2014	6/15/2016	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 23, 2017, Texas Municipal Power Agency (TMPA1) submitted a Self-Report stating that, as a Transmission Owner (TO), it was in noncompliance with PRC-005-1.1b R2. Specifically, TMPA1 did not have documentation that Protection System devices were maintained and tested within the intervals defined in its Protection System Maintenance and Testing Program (PSMP). TMPA1's PSMP required TMPA1 to conduct maintenance and testing on a total of 916 applicable devices, and more specifically, for TMPA1 to conduct various monthly and annual inspections of its substation batteries and battery chargers. TMPA1 failed to provide records of monthly and annual inspections of substation batteries and battery chargers s for 16 of 916 (.017%) of its applicable devices. TMPA1 stated that, while the lack of maintenance and testing documents created a gap in the evidence record, it is confident that the maintenance and testing was performed due to the availability of completed work orders. TMPA1 reported that employee turnover and other employee absences contributed to the noncompliance. The root cause of this noncompliance was TMPA1's reliance on the manual transfer of physical documents from person to person for storage and safeguarding to ensure compliance with PRC-005-1.1b. This failure was further exacerbated by the fact that, during transition of ownership, TMPA1 failed to preserve adequate staffing levels such that the necessary manual transfers of documents were adequately completed. Texas RE determined the noncompliance duration to be from TMPA1's date of registration March 25, 2014, until June 15, 2016, when TMPA1 performed all required battery testing.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Substation battery systems are continuously monitored and alarm points are set by TMPA1. TMPA1 further noted that DC Low and High voltage, positive and negative ground, AC input, and Rectifier status are all monitored via SCADA. No harm is known to have occurred. Texas RE considered TMPA1's compliance history and determined there were no relevant instances of noncompliance.
Mitigation Activity	To mitigate this noncompliance, TMPA1: 1) performed and documented all applicable battery testing; 2) implemented a mobile substation maintenance and testing documentation repository and scheduling application software eliminating the need for employees to manually transfer documents from one person to another; and 3) added new staff to perform day to day operations including maintaining NERC compliance data and records. Texas RE has verified the completion of all mitigation activities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018020841	VAR-002-4.1	R2	Trinity Hills Wind Farm LLC (THWF)	NCR11205	6/1/2018	12/10/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 19, 2018, Trinity Hills Wind Farm LLC (THWF) submitted a Self-Report stating that, as a Generator Operator (GOP), it was in noncompliance with VAR-002-4.1 R2. Specifically, THWF failed to maintain the generator voltage schedule provided by the Transmission Operator (TOP), or meet the conditions of notification for deviations from the voltage schedule. THWF discovered that there were 19 instances where THWF deviated from the allowable parameters of its voltage schedule during the period from June 1, 2018, through December 10, 2018, and that proper notification of the TOP had only occurred for 2 of those instances. To monitor voltage and confirm deviations THWF Operators would view the Seasonal Voltage Profile in the ERCOT Market Information System (MIS) instead of the new Voltage Set Points revised by Dispatch Instructions. As a result, Operators were aware of the deviations from the Seasonal Voltage Profile, but not deviations from a new target Voltage Profile revised by a Dispatch instruction. Because THWF Operators were unaware of deviations from the Voltage Set Points issued through a Dispatch Instruction, they did not report them to their TOP as required by VAR-002-4.1 R2.2. The root cause of this noncompliance was THWF’s failure to deploy systems, and an effective procedure and Operator training, such that Operators would properly monitor voltage performance when a Voltage Support Service (VSS) Dispatch Instruction had altered Voltage Set Points in the Seasonal Voltage Profile. This noncompliance started on June 1, 2018, when THWF first deviated from its Voltage Set Point, and ended on December 10, 2018, when THWF last deviated from its Voltage Set Point.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. First, Texas RE did not identify any trips or outages caused by THWF’s failure to maintain its voltage output or notify its TOP when it did not meet its voltage schedule. Second, the generation Facility at issue is small, with a nameplate rating of 117.5 MW. Third, the deviations from the Voltage Set Point amount to typically 1 kV or less. As a result, the wind generation Facility in question would have had only a negligible impact on the system’s ability to respond to voltage deviations. These factors serve to indicate a minimal risk to reliability due to this noncompliance. No harm is known to have occurred. Texas RE considered THWF’s and its affiliates’ compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, THWF: 1) put in place an additional alarm to alert the Remote Operations Center (ROC) Operator each time the Voltage Set Point changes as a result of an ERCOT VSS Dispatch Instruction; 2) ensured that all ROC Operators are aware of the updated process with respect to voltage monitoring and ERCOT's Voltage Support System (VSS) Dispatch Instructions; 3) edited the ROC Wall screen to add visibility to the new target Voltage Profile and for it to be automatically updated from ERCOT's VSS Dispatch Instructions via a data point from PI; and 4) revised the procedure utilized by ROC Operators to manually update the Voltage Set Point in the DSTATCOM controller system each time the voltage set point changes. Texas RE has verified the completion of all mitigation activities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017753	VAR-002-4	3	Blythe Energy Inc.	NCR11433	June 14, 2017	June 14, 2017	Self-report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 15, 2017 at 17:23, after certification testing, the entity experienced technical issues with its static frequency converter (SFC) and exciter on one 182 MVA generator which caused the automatic voltage regulator (AVR) to exit automatic control and the power system stabilizer (PSS) to turn off. The operator attempted to reset the controller at the generator's local control panel with no success. At 18:09, the operator contacted the Transmission Operator (TOP) to inform it of the status change in the AVR and PSS. Then at 18:55, the entity was finally able to reset its SFC and exciter which allowed the AVR to return to automatic control and the PSS back online. The entity contacted its TOP again and informed it of the status change that put the AVE back to automatic control and the PSS online. An internal review of the situation found that the initial status change notification to the TOP was late by 16 minutes. The entity has a procedure in place that details the requirement to notify the TOP in the event of AVR/PSS status changes as well as documented training materials. The entity also has alarms for the status of its AVR/PSS systems that present to the operators. The entity failed to notify its associated TOP of a status change of the AVR and PSS within 30 minutes of the change, as required by VAR-002-4 R3. The root cause of the issue was the incorrect performance of a task due to a mental lapse while focused on performing another related task. Specifically, during the operators attempt to reset the system, he lost track of time and failed to inform the TOP of the AVR and PSS status changes within the allotted time of the Standard.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to notify its associated TOP of a status change on the AVR and PSS within 30 minutes of the change when the change was not restored within 30 minutes. However, as compensation, the issue lasted only six minutes and during that time, the affected unit remained under control and online during the duration of the issue. There were no significant operational issues to the transmission system, i.e. voltage and vars remained stable throughout the event.
Mitigation	To mitigate this issue, the entity has: a. notified its TOP of the status changes; and b. provided refresher training regarding all VAR-002 reporting requirements with all operators.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017018619	PRC-019-2	R1	AES Alamitos, LLC (ALGS)	NCR05002	7/1/2016	6/17/2017	Self-Report	Completed OR Expected Date 6/20/2018

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On November 13, 2017, ALGS submitted a Self-Report stating that, as a Generator Operator (GO) it was in violation with PRC-019-2 R1. Specifically, ALGS reported that it was not until September 29, 2017 that it discovered, during its preparation for an internal audit that it had an issue with the Standard's implementation plan timeline. ALGS owns a natural gas power plant consisting of six generating Facilities. As of July 1, 2016, ALGS had not coordinated the voltage regulating system controls of any of its Facilities associated with the natural gas power plant's six generating units. On June 17, 2017, four of the six, or 66.67 percent of the generating units of ALGS's gas plant were tested. After reviewing all relevant information, WECC determined that ALGS failed to coordinate the voltage regulating system controls with the applicable equipment capabilities and settings of the applicable Protection System devices in at least 40 percent of its applicable Facilities, as required by PRC-019-2 R1, as set-forth in the implementation plan for version 2 of the Standard by the enforceable date of the Standard. The root cause of the violation was that ALGS didn't adequately track the status of the coordination of the voltage regulating system controls to ensure at least 40 percent of its applicable Facilities were completed, in accordance with the Standard. The entity had initially made arrangements for an external contractor to perform the needed verification, only to later have the contractor rescind its offer to complete the work less than a month prior to the Standard becoming effective. Despite this the entity still had time to perform coordination WECC determined that this violation began on July 1, 2016, when the Standard became mandatory and enforceable and ended on June 17, 2017 when ALGS coordinated the voltage regulating system with its generator capabilities and Protection System devices for its applicable Facilities, for a total of 352 days.
Risk Assessment	WECC determined that this violation posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, ALGS failed to coordinate the voltage regulating system controls with the applicable equipment capabilities and settings of the applicable Protection System devices in at least 40 percent of its applicable Facilities, as required by PRC-019-2 R1, as set-forth in the implementation plan for version 2 of the Standard by the enforceable date of the Standard. Such failure could result in the loss of the generator field, system instability, slipping poles, and damage to the generators. ALGS owns and operates a natural gas power plant with six generating units with a combined capacity of 2,124 MW that was applicable to this issue. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as intermediate. However, ALGS implemented an internal compliance audit and this issue was detected during the preparation. As compensation, the Net Capacity Factor for the Facilities during the time of the violation was only 2.85 percent, further reducing the impact on the BPS. Based on this, WECC determined that there was a low likelihood of causing intermediate harm to the BPS. No harm is known to have occurred. WECC determined that ALGS has no relevant compliance history for this noncompliance. The entity completed verification for unit 1, unit 2, unit 3 and unit 4. Unit 1 and 2 testing was done on 6/17/2017 and the as found setting for Unit 1 and 2 did not require any changes. Unit 3 was tested on 3/13/2017 and changes were required from the as found settings. Specifically, Unit 3's LP "Voltage Regulator" had to have 6 settings changed from the 11 as found settings. Unit 3's LP "As Found AC Range" had to have 2 settings changed from the 4 as found settings. Unit 3's LP "As Left AC Range" had to have 2 settings changed from the 4 as found settings. Unit 3's LP "Minimum Excitation Limiter" had to have 7 settings changed from the 13 as found settings. Unit 3's HP "Voltage Regulator" had to have 8 settings changed from the 11 as found settings. Unit 3's HP "As Found AC Range" had to have 2 settings changed from the 4 as found setting. Unit 3's HP "As left AC Range" had to have 2 settings changed from the 4 as found settings. Unit 3's HP "Minimum Excitation Limiter" had to have 8 settings from the 13 as found settings changed.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017018619	PRC-019-2	R1	AES Alamitos, LLC (ALGS)	NCR05002	7/1/2016	6/17/2017	Self-Report	Completed OR Expected Date 6/20/2018

	Unit 4 was tested on 4/18/2017 and adjustment had to be performed from the as found settings. Specifically, Unit 4's LP "Voltage Regulator" had to have 5 settings changed from the 11 as found settings. Unit 4's LP "As Found AC Range" had to have 1 setting changed from the 4 as found settings. Unit 4's LP "Minimum Excitation Limiter" had to have 12 settings changed from the 14 as found settings. Unit 4's HP "Voltage Regulator" had to have 6 settings changed from the 11 as found settings. Unit 4's HP "As found AC Range" had to have 1 setting changed from the 4 as found settings. Unit 4's HP "Minimum Excitation Limiter" had to have 10 settings changed from the 14 as found settings.
Mitigation	ALGS completed mitigating activities and WECC verified ALGS's mitigating activities. To remediate and mitigate this violation, ALGS: a. completed verification of the setting of the Protection System devices and functions for four of six of its applicable gas plant's generating units; b. completed verification of the setting of the Protection System devices and functions for remaining two of its applicable gas plant's generating units; and c. hired a NERC compliance Analyst who requested that all team leaders at ALGS copy him on their correspondence with contractors regarding NERC deadlines to better assist with meeting compliance deadlines.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017018494	TOP-001-3	R13	Arizona Public Service Company (AZPS)	NCR05016	08/26/2017	09/26/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On October 20, 2017, the entity submitted a Self-Report stating, as a Transmission Operator, it was in noncompliance with TOP-001-3 R13. For the entity's performance of Real-Time Assessments (RTAs), it utilized several tools and displays that provided monitoring, alarming, and situational awareness to assess pre-contingent and post-contingent operating conditions. Specifically, the entity used its Energy Management System (EMS) and Real-time displays, data incoming to its Energy Control Center (ECC) via its System Control and Data Acquisition (SCADA) and/or Inter-Control Center Communications Protocol (ICCP), to perform pre-contingent RTAs of its transmission system. The entity also utilized Real-time Contingency Analysis (RTCA) tools and displays to maintain awareness of conditions to perform an automated post-contingent RTA. The entity's approach to its RTAs was consistent with the guidance provided in Compliance Implementation Guidance Real-time Assessment published by the NERC Operating Committee and the NERC definition of an RTA. However, on August 26, 2017, at 6:42 AM, the entity's ECC Operator observed that its RTCA tool had not provided an updated post-contingency assessment. The ECC Operator immediately contacted the entity's help desk for assistance and after a technical root cause analysis it was determined that the periodic process that triggers the run of the state estimation had stopped, and the RTCA tool could not proceed to calculate the post-contingency assessment. The RTCA tool had alarming capability that should have alerted the ECC Operators of a malfunction however, it was dependent upon the continued functioning of the state estimator process and because the malfunction initiated in the state estimation process, the alarming functionality was not activated. The RTCA tool later resumed functioning at 6:51:39 AM that same day. The entity later indicated that when an issue disrupts the performance of an automated RTA, its ECC Operators follow a procedure which directs them to perform a manual RTA and log the event in their operator log. Despite the circumstances of the issue that occurred August 26, 2017, all previous instances of unsuccessful automated RTAs resulted in the performance of a manual RTA as detailed in the entity's procedure. The entity did identify a specific cause for why the ECC Operator on shift did not follow the procedure to perform a manual RTA and log the event. After reviewing all relevant information, WECC determined the entity failed to ensure that a Real-time Assessment was performed at least once every 30 minutes, as required by TOP-001-3 R13. The root cause of the violation was the lack of internal controls to address the Requirement in the event of an undesirable operation of the RTCA tool that prevented its correct operation. This violation began on at 2:18:46 AM on August 26, 2017, thirty-one minutes after the entity's last successful RTA and ended at 6:51:39 AM on the same day, when the next RTA was performed, for a total of four hours, 32 minutes and 53 seconds.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Failure to perform Post-contingency real time analysis could result in the entity not being completely aware of the state if its system for contingent conditions. This could inhibit the entity's ability to develop sufficient actions were inhibited to prevent potential exceedance of a System Operating Limit, instability, uncontrolled separation, or cascading outages that could adversely impact the reliability of the Western Interconnection. However, the entity had strong compensating controls in place during the time of the noncompliance. Specifically, the entity maintained awareness or pre-contingency system conditions through its EMS and associated real-time displays to perform its real-time or pre-contingent monitoring and assessment of its transmission system. In addition, during the period of noncompliance, the entity displayed the RC's RCTA tool which activates alarms when an adverse system operating condition is identified and post-contingent. This model includes all of the entity's transmission system and did not identify any potential post-contingent adverse system operating conditions. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, the entity: 1) performed the RTA; 2) instituted a Standing Order directing transmission operating staff to verify and confirm that the RTCA tool is operational every 30 minutes until further notice; 3) implemented SIEMENS code fix to prevent future RTCA tool process failures; and 4) configured and implemented an independent health monitor system to monitor the status of the RTCA tool and ensure that the alarm would sound if there is a future system failure.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020262	VAR-002-4.1	R1	Dominion Solar Projects III, Inc.	NCR11633	06/28/2018	07/10/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On August 21, 2018, the entity submitted Self-Reports stating, as a Generator Operator (GOP), it was in noncompliance with VAR-002-4.1 R1 and R3. Specifically, on July 10, 2018, while preparing a NERC Monthly Checklist for its seven solar farms, the entity discovered that on June 28, 2018, one of its generating units had the automatic voltage control mode of its Automatic Voltage Regulator (AVR) inadvertently turned off and placed in the power factor control mode. The status change occurred when the plant Operator accidentally clicked on the automatic voltage control mode toggle while attempting to open another screen in the human machine interface. After the Operator had toggled the automatic voltage control mode, an alarm was sent via email that identified the change in the automatic voltage control mode of the AVR. The Operator did not act upon the alarm based on his experience with other automatic voltage control mode alarms self-clearing for unregistered Facilities and these alarms were not differentiated from higher priority alarms. In addition, the Operator did not validate the automatic voltage control mode alarm because the alert had no features indicating its importance and time sensitivity. The entity did not have an exemption from its Transmission Operator (TOP), as required by VAR-002-4.1 R1, nor had the status change been communicated to the TOP, exceeding the 30-minute notification requirement, per VAR-002-4.1 R3 After reviewing all relevant information, WECC determined the entity failed to operate each generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the TOP, as required by VAR-002-4.1 R1. Additionally, the entity failed to notify its associated TOP of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change, as required by VAR-002-4.1 R3. The root cause of these issues was the entity's lack of controls to alert the user of changes in the automatic voltage control mode of its AVR, and issues with several users logging in and out of the plant controller system with a single shared account causing the automatic voltage control mode on its AVR to be inadvertently changed without alerting the user. WECC determined that these issues began on June 28, 2018 when the entity's generating unit's AVR status was changed to a different control mode without notifying the TOP and ended on July 10, 2018 when the entity changed the generating unit's AVR status back to the automatic voltage control mode, and notified its TOP, for a total of 13 days.
Risk Assessment	WECC determined these issues posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, the entity failed to operate each generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the TOP, as required by VAR-002-4.1 R1. Additionally, the entity failed to notify its associated TOP of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change, as required by VAR-002-4.1 R3. However, the entity implemented good detective controls. Specifically, NERC monthly checklists, which track compliance and evidence for various Standards and Requirements. These checklists include the AVR status reports and internal program reports which are reviewed after completion by the entity's corporate office that led to the discovery of the above issues. As further compensation, the entity also provided evidence that the generator voltage schedules were maintained during the period of non-compliance. No other issues at the other Facilities were discovered and they remained unaffected by the issues related to this Facility.
Mitigation	The entity submitted a Mitigation Plan to address this issue and WECC accepted the entity's Mitigation Plan. To remediate and mitigate this issue, the entity has: a. changed the AVR status from power factor control mode to automatic voltage control mode; b. notified the entity's TOP of the AVR status change; c. modified an Operator instruction log to require the operations control center to verify that plant controller is in the correct mode during each shift change; d. modified alerts from the Ignition system so that all NERC registered Facilities are isolated to a unique page with alarms that pop up on the video wall along with audio notifications and red banners; e. implemented a procedure that requires acknowledgement between the current user, prior to the alternate users signing in to the plant controller using the single sign-on feature. As part of the implementation for this procedure, verbal training was conducted to ensure all users were aware of the change; and f. enabled the plant controller feature from hover click to arm/execute when switching from automatic voltage control mode to power factor control mode or when disabling either mode. The arm/execute feature requires the user to acknowledge a change in the automatic voltage control function in a separate screen before the change is committed. The entity submitted a Mitigation Plan Completion Certification and WECC verified the entity's completion of Mitigation Plan.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020263	VAR-002-4.1	R3	Dominion Solar Projects III, Inc.	NCR11633	06/28/2018	07/10/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On August 21, 2018, the entity submitted Self-Reports stating, as a Generator Operator (GOP), it was in noncompliance with VAR-002-4.1 R1 and R3. Specifically, on July 10, 2018, while preparing a NERC Monthly Checklist for its seven solar farms, the entity discovered that on June 28, 2018, one of its generating units had the automatic voltage control mode of its Automatic Voltage Regulator (AVR) inadvertently turned off and placed in the power factor control mode. The status change occurred when the plant Operator accidentally clicked on the automatic voltage control mode toggle while attempting to open another screen in the human machine interface. After the Operator had toggled the automatic voltage control mode, an alarm was sent via email that identified the change in the automatic voltage control mode of the AVR. The Operator did not act upon the alarm based on his experience with other automatic voltage control mode alarms self-clearing for unregistered Facilities and these alarms were not differentiated from higher priority alarms. In addition, the Operator did not validate the automatic voltage control mode alarm because the alert had no features indicating its importance and time sensitivity. The entity did not have an exemption from its Transmission Operator (TOP), as required by VAR-002-4.1 R1, nor had the status change been communicated to the TOP, exceeding the 30-minute notification requirement, per VAR-002-4.1 R3 After reviewing all relevant information, WECC determined the entity failed to operate each generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the TOP, as required by VAR-002-4.1 R1. Additionally, the entity failed to notify its associated TOP of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change, as required by VAR-002-4.1 R3. The root cause of these issues was the entity's lack of controls to alert the user of changes in the automatic voltage control mode of its AVR, and issues with several users logging in and out of the plant controller system with a single shared account causing the automatic voltage control mode on its AVR to be inadvertently changed without alerting the user. WECC determined that these issues began on June 28, 2018 when the entity's generating unit's AVR status was changed to a different control mode without notifying the TOP and ended on July 10, 2018 when the entity changed the generating unit's AVR status back to the automatic voltage control mode, and notified its TOP, for a total of 13 days.
Risk Assessment	WECC determined these issues posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, the entity failed to operate each generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the TOP, as required by VAR-002-4.1 R1. Additionally, the entity failed to notify its associated TOP of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change, as required by VAR-002-4.1 R3. However, the entity implemented good detective controls. Specifically, NERC monthly checklists, which track compliance and evidence for various Standards and Requirements. These checklists include the AVR status reports and internal program reports which are reviewed after completion by the entity's corporate office that led to the discovery of the above issues. As further compensation, the entity also provided evidence that the generator voltage schedules were maintained during the period of non-compliance. No other issues at the other Facilities were discovered and they remained unaffected by the issues related to this Facility.
Mitigation	The entity submitted a Mitigation Plan to address this issue and WECC accepted the entity's Mitigation Plan. To remediate and mitigate this issue, the entity has: a. changed the AVR status from power factor control mode to automatic voltage control mode; b. notified the entity's TOP of the AVR status change; c. modified an Operator instruction log to require the operations control center to verify that plant controller is in the correct mode during each shift change; d. modified alerts from the Ignition system so that all NERC registered Facilities are isolated to a unique page with alarms that pop up on the video wall along with audio notifications and red banners; e. implemented a procedure that requires acknowledgement between the current user, prior to the alternate users signing in to the plant controller using the single sign-on feature. As part of the implementation for this procedure, verbal training was conducted to ensure all users were aware of the change; and f. enabled the plant controller feature from hover click to arm/execute when switching from automatic voltage control mode to power factor control mode or when disabling either mode. The arm/execute feature requires the user to acknowledge a change in the automatic voltage control function in a separate screen before the change is committed. The entity submitted a Mitigation Plan Completion Certification and WECC verified the entity's completion of Mitigation Plan.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019432	VAR-501-WECC-3.1	R1	Grays Harbor Energy LLC (GHE)	NCR02551	December 29, 2017	March 7, 2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On March 23, 2018, the entity submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with VAR-501-WECC-3.1 R1. Specifically, the entity did not provide the written Power System Stabilizer (PSS) operating specifications to the Transmission Operator (TOP) within 180 days of the effective of the date of the Standard, or December 28, 2017. This could potentially result in the TOP not including the correct status of the PSS for the generating Facility in its Operating Plan and Real-Time Assessment. This could also cause a voltage deviation at the Point of Interconnection and could hinder voltage support in the case of an event. On March 7, 2018 the entity provided its Operating Procedure to its TOP describing those known circumstances during which the Generator owner's PSS would not be providing an active signal to the AVR. After reviewing all relevant information, WECC determined the entity failed to provide to its TOP, its written Operating Procedure or other document(s) describing those known circumstances during which the its PSS would not be providing an active signal to the Automatic Voltage Regulator (AVR), within 180 days, of the effective date of the Standard, as required by VAR-501-WECC-3.1 R1. The root cause of the issue was an administrative oversight in the entity's compliance program by not tracking the required tasks associated with the Standard. This issue began on December 29, 2017, 180 days of the effective date of the Standard and ended on March 7, 2018, when the entity emailed the proper procedures to the TOP, for a total of 69 days.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to provide to its TOP, its written Operating Procedure or other document(s) describing those known circumstances during which the its PSS would not be providing an active signal to the Automatic Voltage Regulator (AVR), within 180 days, of the effective date of the Standard, as required by VAR-501-WECC-3.1 R1. The entity did not implement any preventative or detective controls to prevent the above issue from occurring. However, as a compensating control the entity's policy was to keep its PSS in service on generating units, so that if there were a voltage excursion the PSS would have provided the designed disturbance damping.
Mitigation	The entity completed mitigating activities and WECC verified the entity's mitigating activities. To remediate and mitigate this issue, the entity has: g. developed procedures to outline PSS operating requirements at the entity's facilities to describe known circumstances during which the PSS will not be providing an active signal to the AVR and instructions on how to provide this operating information to the entity's TOP; h. provided procedures containing the PSS operational specifications to the TOP; and i. implemented an automated task reminder to review procedures every 5 months as a preventative measure. As part of the review the entity will confirm if any changes have been made to the PSS operating specifications or the PSS and VAR equipment, including tuning that could affect the PSS operational specifications. If any of these changes have been made the procedure will be updated and sent to the TOP within 180 days.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020105	IRO-018-1(i)	R3	Peak Reliability (PEAK)	NCR10289	04/01/2018	07/12/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On July 20, 2018, the entity submitted a Self-Report stating, as a Reliability Coordinator, it was in noncompliance with IRO-018-1(i) R3. During an annual internal control evaluation on July 5, 2018, the entity discovered that the complete suite of methods developed to notify System Operators of an alarm process monitor failure had not been implemented, as required by IRO-018-1(i) R3. Only two notifications of five had been implemented before April 1, 2018, the mandatory and enforceable date of the Standard: energy management system (EMS); and an email notification to IT personnel, who would then notify the System Operators. On July 12, 2018, after this issue was discovered, the entity implemented the remaining notification methods: email notification to System Operators; text notification to System Operator control room cell phone; and activation of the control room alert beacon. After reviewing all relevant information, WECC determined the entity failed to appropriately implement its alarm process monitor that provides notification(s) to its System Operators when a failure of its Real-time monitoring alarm processor has occurred, as required by IRO-018-1(i) R3. The root cause of the issue was a lack of internal controls to ensure that the entity completed the implementation of the notifications and ensure that the notifications were functioning as designed. This issue began on April 1, 2018, when the Standard became mandatory and enforceable and ended on July 12, 2018, when the entity implemented the remaining three notifications to its System Operators, for a total of 103 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The entity implemented weak preventative controls to prevent this issue from occurring. However, the entity implemented good detective controls in its annual internal controls evaluations, which detected the above issue. As further compensation, had the real-time alarm monitor been deployed, the entity had implemented two of the notification methods: EMS and an email to IT who would have notified the System Operators. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, the entity: 1) implemented an email notification to System Operators; 2) implemented control room alert beacon; 3) implemented text notification to System Operator control room cell phone; and 4) implemented a formal procedure to address the cause of the notification implementation failure. Specifically, procedure documents roles, responsibilities, and the steps for monthly testing of the Alarm Process Monitor failure notification methods. WECC has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017875	PER-003-1	R3	Portland General Electric Company	NCR05325	March 25, 2017	May 4, 2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On June 30, 2017, the entity submitted a Self-Report stating, as a Balancing Authority (BA), it was in noncompliance with PER-003-1 R3. Specifically, on March 23, 2017 a System Operator's NERC Reliability Operator Certification expired. The System Operator did not renew his certification before performing BA reliability-related tasks on March 25, 2017. The entity did not renew his certification until May 4, 2017 when the System Operator submitted a renew request for the Operator's Reliability certification that was approved on the same day. During the time the System Operator was not certified he continued to perform Real-time reliability-related tasks. The entity had a System Control Center (SCC) training program manager who reviewed certification renewal dates and continuing education hours (CEH) at the beginning of each year when issuing individual System Operator development plans. At that time, the System Operator acknowledged the impending renewal date. However, there was not a task for the manager to follow-up on renewals. Additionally, email remainders are sent by NERC to the System Operators when their certification is coming due for renewal. However, in this instance, these reminders were not seen by the System Operator because they went to the email junk folder. After reviewing all relevant information, WECC determined the entity failed to staff its Real-time positions performing BA reliability-related tasks, with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining a valid NERC Reliability Operator certification, per PER-003-1 R3. The root cause of the issue was a lack of management oversight for the renewal of the NERC Reliability Operator certification after the initial notification. Specifically, the entity had a System Control Center (SCC) Training Program Manager who reviewed certificate renewal dates at the beginning of each year when issuing individual development plans. However, the Manager did not confirm that the System Operator had completed the training after the initial discussion at the beginning of the year. This issue began on March 25, 2017, when the System Operator's NERC Reliability Operator certification and ended on May 4, 2017, when the Operator certification was approved, for a total of 41 days.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to staff its Real-time positions performing BA reliability-related tasks with System Operators who have demonstrated minimum competency in the areas listed by obtaining and maintaining a valid NERC Reliability Operator certification, per PER-003-1 R3. However, as compensation, although the System Operator worked ten shifts with a suspended System Operator's NERC Reliability Operator certification, the individual had already completed 200 hours of CEH required to renew his certification, prior to the expiration date of his certificate. Therefore, this issue was more administrative in nature and would be unlikely to impact the reliability of the BES.
Mitigation	The entity completed mitigating activities and WECC verified the completion of the entity's mitigating activities. To remediate and mitigate this issue, the entity has: j. renewed the System Operator's NERC Reliability Operator Certification; k. reviewed all NERC training certification dates to identify any pending renewals and notified BA Operators and Transmission and Distribution Operators (T&D) of upcoming NERC certifications; l. confirmed that none of SCC System Operator's NERC certifications would be lapsing; m. discussed the topic of managing NERC training recertification's and the need for BA Operators and T&D Operators to communicate with SCC management and the SCC training program manager when pending NERC System Operator's renewal date approaches and when certification is completed; n. instructed SCC Operators of the importance of adding NERC email addresses to the entity's white lists; o. informed SCC Operators reminding of their responsibility to have a valid NERC certification; p. updated the individual development plans to include the shared responsibility between the individual and the manager to ensure that the individual's NERC Reliability Operator Certification was renewed before the deadline; q. implemented monthly meetings with the SCC training program manager to review pending renewals with SCC management; and r. tasked the SCC training program manager with notifying the SCC Operators when their renewal is approaching and confirming the CEHs and recertification expectations.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019601	FAC-014-2	R2	Portland General Electric Company	NCR05325	April 1, 2017	March 11, 2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On April 27, 2018, the entity submitted a Self-Report stating, as a Transmission Operator (TOP), it was in noncompliance with FAC-014-2 R2. The entity's Reliability Coordinator (RC) SOL methodology stated that an SOL exceedance is characterized by a condition when the calculated post-contingency flow on a Facility is above the highest emergency rating. However, prior to April 1, 2017, the entity had used a single value for both its normal rating and emergency rating for transmission system SOLs, with both SOLs equal to the entity's continuous Facility Ratings for any applicable transmission Facility. On April 1, 2017, the entity revised its 30-minute emergency SOL rating and defined it as 125% of a Facility's seasonal normal rating, limited only by the entity or another entity's Facility Rating methodology. However, the entity overlooked an updated version of its RC's SOL methodology requiring that the time-dependent 30-minute emergency rating must not exceed Facility Ratings that have been established consistent with the entity's Facility Rating methodology. According to the entity's methodology for SOLs in the operations horizon the entity's transmission system SOLs were thermal ratings defined as the most limiting element from terminal to terminal. Therefore, while the SOLs which the entity developed were consistent with the entity's methodology for SOLs, the 125% 30-minute emergency rating did not originate from, and in fact exceeded, the entity's equipment Facility Rating, which was inconsistent with the RC's SOL methodology. After reviewing all relevant information, WECC determined the entity failed to establish SOLS (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that were consistent with its Reliability Coordinator's SOL Methodology, as required by FAC-014-2 R2. The root cause of the issue was the lack of internal controls. The entity overlooked details in the RC's methodology update concerning Facility Ratings resulting in inconsistent SOLs, per the Standard, being published by the entity. The entity did not have any sort of control in place to verify the appropriateness or accuracy of the changes made to the methodology. This issue began on April 1, 2017, when the entity did not establish a SOL as directed by its RC and ended on May 11, 2018 when the entity updated its emergency rating SOL as directed by its RC, for a total of 406 days.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to establish SOLS (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology, as required by FAC-014-2 R2. The entity implemented an annual review of compliance with Reliability Standards that detected this issue. As further compensation, the entity's design criteria included an additional margin on its Facility Ratings to avoid clearance issues. Lastly, the possibility that a transmission Facility in issue could operate above its Facility Rating was remote. For example, a combination of extreme ambient temperatures, low wind speed, and heavy system loading would have had to occur simultaneously with a critical N-1 contingency before a conductor would be at risk of loading beyond its thermal operating capability. Additionally, the entity's day ahead and Real-time Assessments identified contingency events where a Facility could potentially exceed its continuous rating, and Operating Plans were developed to mitigate those potential exceedances, where identified.
Mitigation	The entity submitted a Mitigation Plan to address this issue and WECC accepted the entity's Mitigation Plan. To remediate and mitigate this issue, the entity has: s. updated its Facility ratings methodology to incorporate the approach for the for the establishment of 30-minute Facility Ratings for conductors and terminal Facilities that are consistent with the entity's Facility Ratings methodology; t. established revised 30-minute emergency rating SOLs that are consistent with its RC's methodology and do not exceed the associated equipment's Facility Ratings; u. issued a revised 30-minute emergency rating SOLs to the RC for use in operational planning analyses and Real-time assessments; and v. created a process for establishing and communicating Facility Ratings and the associated thermal SOLs that include engineering review before new or revised Facility Ratings and the associated SOLs are finalized. The entity submitted a Mitigation Plan Completion Certification and WECC verified the entity's completion of Mitigation Plan.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017018878	TOP-003-3	R5	Portland General Electric Company	NCR05325	June 20, 2017	September 14, 2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On December 21, 2017, the entity submitted a Self-Report stating, as a Generator Operator, it was in noncompliance with TOP-003-3 R5. Specifically, on June 20, 2017, at 8:50 PM, one of the entity's generating units tripped, resulting in a loss of 200 MW. The entity did not verbally notify its neighboring TOP; however, it did verbally notify the Reliability Coordinator (RC) of the trip at 9:00 PM. On July 5, 2017, at 1:50 PM, another generating unit tripped causing a loss of 428 MW. The entity did not verbally notify its neighboring TOP; however, it did verbally notify its RC at 2:14 PM. After reviewing all relevant information, WECC determined the entity failed to satisfy the obligations of the documented specifications with its neighboring TOP using a mutually agreeable: format, process for resolving data conflicts, and security protocol as required by TOP-003-3 R5. The root cause of the issue was the entity's infrequent performance of notifying its neighboring TOP of outages outside of the entity's own TOP area. This issue began on June 20, 2017, when the entity did not notify its neighboring TOP of one of the two forced generator outages and ended on September 14, 2017, when the entity alerted its neighboring TOP of the outages that occurred on June 20, 2017, and July 5, 2017, for a total of 87 days.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to satisfy the obligations of the documented specifications with its neighboring TOP using a mutually agreeable: format, process for resolving data conflicts, and security protocol as required by TOP-003-3 R5. The entity implemented good detective controls. Specifically, each quarter the entity's grid engineering and compliance (GEC) group identifies every instance of a plant trip greater or equal to 50 MW that occurred during the last quarter. Each instance is then crossed checked with recorded phone calls to ensure that the appropriate notifications to the neighboring TOP were made. After the quarterly review is completed, GEC staff meets with GEC management to present their findings and to verify that no additional instances of plant tripping that would require notification to the neighboring TOP under TOP-003-3 R5 occurred during the quarter. These two issues were identified by this detective control. As a compensating control, the entity notified the RC within 30 minutes of each outage.
Mitigation	The entity completed mitigating activities to address this issue and WECC verified the completion of the entity's mitigating activities. To remediate and mitigate this issue, the entity has: w. notified its neighboring TOP of the two instances of forced outages and of its failure to notify them timely; and x. requested that its neighboring TOP provide a single phone numbers to use for each of its plants in its transmission area in case they needed to notify them of an outage in the future. This phone number has been added to the entity's operator phone console speed dial and an email was sent to System Operators reminding them to use this number when reporting forced outages; y. sent an email to all of its System Operators reminding them of the importance of making these notifications and that their scorecards would reflect any missed calls; and z. updated its System Operator log to include a shift change checklist that must be checked off at the end of every shift.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019784	TOP-001-3	R13	Public Utility District No. 1 Snohomish County (SNPD)	NCR05335	February 17, 2018	February 17, 2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On June 1, 2018, the entity submitted a Self-Report stating that, as a Transmission Operator (TOP), it was in noncompliance with TOP-001-3 R13. On February 17, 2018, a wind storm lasting approximately 12 hours caused the entity to receive over 700 various alarms throughout its System. Previously, the entity had implemented alarms to notify its System Operators of when its Reliability Coordinator's (RC) Hosted Advanced Application (HAA) and Real-time Contingency Analyses (RTCA) tools were dysfunctional and therefore not available to use to perform a Real-time Assessment (RTA). During the wind storm, the System Operator performed an RTA through its RTCA tool at 8:53 PM, but did not perform an RTA at 9:24 PM, 30 minutes later. At 9:29 PM, the entity's System Operator received an alarm notifying him that the RTCA tool was dysfunctional, which he acknowledged. However, the System Operator should then have performed a manual back-up RTA log every 25 minutes during the loss of the RTCA tool, which also did not occur. Ultimately, at 10:05 PM, the System Operator performed an RTA, 41 minutes past the 30-minute requirement. After reviewing all relevant information, WECC determined that the entity failed to ensure an RTA was performed at least once every 30 minutes, per TOP-001-3 R13. The root cause of the issue was the System Operator not following the entity's processes for performing an RTA, prior to and during the loss of the RC's HAA/RTCA tool. This issue began on February 17, 2018, at 9:24 PM, when the 30-minute RTA should have occurred and ended on February 17, 2018 at 10:05 PM when the next RTA was performed, for a total of 41 minutes.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to ensure that a RTA was performed at least once every 30 minutes, per TOP-001-3 R13. The entity implemented preventative controls to prevent the above issue from occurring. Specifically, the entity implemented alarms to notify its System Operators when the HAA and RTCA tools were down, that then prompts the system operators to ensure that a manual RTA is performed every 25 minutes. However, even though the System Operator acknowledged the alarm he neglected to perform an RTA because of the influx of 700 various alarms due to the windstorm across the entity's distribution system. The entity also implemented detective controls to detect the above issue. The entity attends a monthly review with its RC, during this meeting the PC shared that its RTCA tool was dysfunctional for 71 minutes. From this discussion with the RC, the entity discovered it did not follow its processes, resulting in the issue above. As further compensation, the entity is a load serving entity and by design, any loss of load or resources would have been confined to its system and would not likely affect the BPS.
Mitigation	The entity completed mitigating activities and on August 8, 2018, WECC verified the entity's mitigating activities. To remediate and mitigate this issue, the entity has: a. performed an RTA; b. retrained the system operator on duty at the time of this event on procedures to follow when the HAA tool is dysfunctional; c. emailed all system operators to inform them of the event and to provide a fresher on HAA alarm procedures; d. sent alarms to the entity superintendent via email and text to act as a backup for system operators; e. imbedded a note into the alarms to remind System Operators to reference the appropriate procedure when the HAA is unavailable; and f. assigned the ECC operations engineer to perform a monthly review of the entity's RC website exception report.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019433	VAR-501-WECC-3.1	R1	Spindle Hill Energy LLC (SPHE)	NCR05529	December 29, 2017	March 7, 2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On March 23, 2018, the entity submitted a Self-Report stating that, as a Generator Operator (GO), it was in noncompliance with VAR-501-WECC-3.1 R1. Specifically, the entity reported that it did not provide the written Power System Stabilizer (PSS) operating specifications to the Transmission Operator (TOP) within 180 days of the effective of the date of the Standard or December 28, 2017. This could potentially result in the TOP not including the correct status of the PSS for the generating Facility in its Operating Plan and Real-Time Assessment. This could also cause a voltage deviation at the Point of Interconnection and could hinder voltage support in the case of an event. On March 7, 2018 the entity provided its operating procedure to its TOP describing those known circumstances during which the Generator owner's PSS would not be providing an active signal to the AVR. After reviewing all relevant information, WECC determined that the entity failed to provide to its Transmission Operator, the Generator Owner's written Operating Procedure or other document(s) describing those known circumstances during which the Generators Owner's PSS will not be providing an active signal to the Automatic Voltage Regulator (AVR), within 180 days, of the effective date of the Standard, as required by VAR-501-WECC-3.1 R1. The root cause of the issue was an administrative oversight in the entity's compliance program by not tracking the required tasks associated with the Standard. WECC determined that this issue began on December 29, 2017, 180 days after the effective date of the Standard and ended on March 7, 2018, when the entity emailed the proper procedures to the TOP, for a total of 69 days.
Risk Assessment	WECC determined that this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to provide to its Transmission Operator, the Generator Owner's written Operating Procedure or other document(s) describing those known circumstances during which the Generators Owner's PSS will not be providing an active signal to the Automatic Voltage Regulator (AVR), within 180 days, of the effective date of the Standard, as required by VAR-501-WECC-3.1 R1. The entity did not implement any preventative or detective controls to prevent the above non-compliance from occurring. However, as a compensating control the entity's policy was to keep its PSS in service on generating units, so if that if there were a voltage excursion the PSS would have provided the designed disturbance damping if there were a voltage excursion during the instant case, therefore making the above risk administrative in nature.
Mitigation	The entity completed mitigating activities and WECC verified the entity's mitigating activities. 1. To remediate and mitigate this issue, the entity has: aa. developed procedures to outline PSS operating requirements at the entity's facilities to describe known circumstances during which the PSS will not be providing an active signal to the AVR and instructions on how to provide this operating information to the entity's TOP; bb. provided procedures containing the PSS operational specifications to the entity's TOP on; and cc. implemented an automated task reminder to review procedures every 5 months as a preventative measure. As part of the review the entity will confirm if any changes have been made to the PSS operating specifications or the PSS and VAR equipment, including tuning that could affect the PSS operational specifications. If any of these changes have been made the procedure will be updated and sent to the TOP within 180 days.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019755	PRC-004-5(i)	R5	City of Tacoma, Department of Public Utilities, Light Division	NCR05097	12/5/2017	3/7/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On May 24, 2018, the entity submitted a Self-Report stating, as a Distribution Provider (DP), Generator Operator (GO) and Transmission Owner (TO), it was in noncompliance with PRC-004-5(i) R5. On October 1, 2017, the entity experienced a Misoperation. On October 11, 2017, the entity determined the cause of the Misoperation was due to wiring problems with a relay. The entity should have developed a Corrective Action Plan (CAP) or explained in a declaration why corrective actions would be beyond its control and would not improve BES reliability, by December 10, 2017, 60-days from first identifying a cause of the Misoperation. However, the entity developed a CAP for the Misoperation on February 15, 2018, 67 days after the 60-day deadline. On October 2, 2017 the entity experienced a second Misoperation. On October 5, 2017, the entity determined the cause of the Misoperation was a design error through the incorrect loss of potential settings. However, a CAP for this Misoperation was completed on March 7, 2018, 94 days after the 60-day deadline. After reviewing all relevant information, WECC determined the entity failed to develop a CAP for the identified Protection System components, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations, within 60 calendar days of first identifying the causes of the Misoperations, as required by PRC-004-5(i) R5. The root cause of the issue was that the entity failed to provide sufficient training to its new personnel on the compliance requirements for Misoperation identification and the timing requirement for submitting a CAP, once a cause of a Misoperation has been identified. The first issue began on December 11, 2017, 60 days after the cause of the first Misoperation was identified and the CAP was due and ended on February 15, 2018, when a CAP was completed, for a total of 67 days The second issue began on December 5, 2017, 60 days after the cause of the second Misoperation was identified and the CAP was due and ended on March 7, 2018, when the CAP was completed for a total of 94 days of noncompliance.
Risk Assessment	WECC determined these issues posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, the entity failed to develop a CAP for the identified Protection System components, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations, within 60 calendar days of first identifying the causes of the Misoperations, as required by PRC-004-5(i) R5. However, the entity implemented detective controls to detect the above issue. Specifically, the entity conducts a quarterly review of Misoperations prior to submitting them to an internal software program. This quarterly review discovered the above issues. Furthermore, if the cause of the Misoperation was more widespread, multiple transmission line terminals at one substation could potentially trip open during switching. However, as compensation, the entity's system is designed to lose one bus due to an unplanned event with minimal impact to the BPS.
Mitigation	The entity submitted a Mitigation Plan to address this issue and WECC accepted the entity's Mitigation Plan. To remediate and mitigate this issue, the entity has: dd. completed a CAP for each Misoperation, as stated above; ee. created a full process flow chart to tie together the processes and forms to increase understanding of when and how to use each form; ff. trained all necessary staff on the protection system operation review processes and flow charts developed in point A; and gg. scheduled ongoing monthly Misoperation status checks by its supervisors or delegates The entity submitted a Mitigation Plan Completion Certification, WECC verified the entity's completion of Mitigation Plan.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020273	TOP-001-3	R13	City of Tacoma, Department of Public Utilities, Light Division	NCR05097	2/17/2018	2/17/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On August 22, 2018, the entity submitted a Self-Report stating that, as a Transmission Operator (TOP), it was in noncompliance with TOP-001-3 R3. Specifically, on February 17, 2018 at 20:54 MST the entity performed a valid Real-Time assessment (RTA). Per TOP-001-3 R3, the subsequent RTAs were due every 30 minutes, at 21:24 MST and 21:54 MST. The entity utilizes the Reliability Coordinator's Hosted Advanced Application (HAA) for performing Real-time Contingency Analyses (RTCA). However, the RTCA tool was dysfunctional. As a result, the entity did not perform the next valid RTA until 22:05 MST because the entity's operators assumed that the HAA was still functional and that its automated RTA's were still being performed. After reviewing all relevant information, WECC determined that the entity failed to ensure that a RTA was performed at least once every 30 minutes, as required by TOP-001-3 R13. The root cause of the issue was that the entity did not train the operator to perform a manual RTA when there was a RTCA/HAA tool failure. This issue began on February 17, 2018 at 20:54 MST, 30 minutes after previous valid RTA at 20:24 MST and ended on February 17, 2018 at 22:05 MST when the entity performed a valid RTA, for a total of 71 minutes.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, the entity failed to ensure that a RTA was performed at least once every 30 minutes as required by TOP-001-3 R13 During this specific RTCA outage, if the cause of the Misoperation was more widespread, multiple transmission line terminals at one substation could potentially trip open during switching. However, the type of switching that contributed to this Misoperation is not common in the entity's transmission system, and no similar events are known to have occurred previously. There were no changes in system conditions and no forced or planned outages.
Mitigation	The entity submitted a Mitigation Plan to address this issue and WECC accepted the entity's Mitigation Plan. To remediate and mitigate this issue, the entity has: a. performed the RTA; b. implemented EMS Alarming to indicate the status of RTCA data; c. implemented remedial training for lessons learned for RTCA outage event; d. updated the RTA Standard Operating Procedure to specify actions required by the System Power Dispatcher to ensure an RTA is performed every 30 minutes, in the event of a loss of RTCA functionality; and e. trained System Operators on the RTA SOP changes. The entity submitted a Mitigation Plan Completion Certification and WECC verified the entity's completion of Mitigation Plan.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019370	TOP-001-3	R9	Tri-State Generation and Transmission Association, Inc. – Reliability	NCR10030	05/23/2017	06/23/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On March 7, 2018, the entity submitted a Self-Report stating that, as a Transmission Operator, it was in noncompliance with TOP-001-3 R9. Specifically, on February 4, 2018, while preparing for an audit, the entity discovered that not all notifications to impacted interconnected entities were made after an unplanned outage had occurred on May 23, 2017. During this outage, all Inter-Control Center Communications Protocol (ICCP) links were lost. The outage began at 3:50 PM and ended at 4:39 PM for a total of 49 minutes. The System Operator was aware of this notification requirement however, he only notified three of the thirteen impacted interconnected entities he was required to notify. This could have resulted in interconnected entities being unaware that ICCP data from the entity was unavailable for Real-time monitoring of the System. This could also have potentially impacted Real-Time operating decisions by these entities to prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection. After reviewing all relevant information, WECC determined the entity failed to notify ten of its thirteen known impacted interconnected entities of an unplanned outage that lasted more than 30 minutes, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities, as required by TOP-001-3 R9. The root cause of the issue was the lack of sufficient notification tracking processes. This issue began on May 23, 2017, at 4:21 PM, when the entity's operator failed to notify all of the required impacted entities of the unplanned outage and ended on May 23, 2017, at 4:39 PM when the ICCP links were restored, for a total of 18 minutes.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to notify ten of its thirteen known impacted interconnected entities of an unplanned outage that lasted more than 30 minutes, for telemetering and control equipment, monitoring and assessment capabilities, and associated communication channels between the affected entities in the entity's footprint, as required by TOP-001-3 R9. The entity had weak preventative and detective controls as the above issue was not discovered for several months. However, as a compensating control the entity had full visibility of its internal system during the 49-minute outage with no effect on its operations and the functionality of its Real-Time Assessment being unharmed.
Mitigation	The entity completed mitigating activities and WECC verified completion of the mitigating activities. To remediate and mitigate this issue, the entity has: hh. remediation occurred when the ICCP links were restored and the outage ended ii. informed system operators of the instant issue and were reminded of the requirements of the Standard; jj. implemented a new alarm control checklist for RTU and ICCP failures that utilizes the entity's dashboard tool. This dashboard tool includes a checklist for failures greater than 30 minutes that will appear and prompt the operator to acknowledge that they have completed the required items on the dashboard's checklist; and kk. delivered a PowerPoint to train the Operators on communication failure notifications, including information on how the dashboard and checklists were implemented.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017121	PRC-024-2	R2	Windstar Energy, LLC (WSTAR)	NCR11292	7/1/2016	6/5/2018	Self-Certification	Completed OR Expected Date 6/22/2018

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On February 28, 2017, WSTAR submitted a Self-Certification stating that, as a Generator Owner (GO), it was in issue with PRC-024-2 R2. Specifically, WSTAR reported that it did not set its protective relaying for its system controls for its 120 MW wind generation Facility because an internal engineering evaluation of the protection system relays was not performed prior to the mandatory and enforceable date of the Standard. The 120 MW is a dispersed generating Facility comprised of 60 individual 2 MW wind turbines identified through Inclusion I4 of the Bulk Electric System definition. For this type of Facility, this requirement applies to voltage protective relays applied on the individual generating unit of the dispersed power producing resources, as well as voltage protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection. On June 5, 2018, third-party consultants conducted testing of WSTAR's generator voltage protective relays to ensure that they did not trip within the "no trip zone," per the requirements of PRC-024-2 R2, Attachment 2. The third-party consultants found that the protective relay settings were found to trip within the "no trip zone" and adjusted the settings of the protection system devices to not trip within the "no trip zone". After reviewing all relevant information, WECC determined that WSTAR failed to set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone," of PRC-024 R2, Attachment 2. The root cause of the issue was WSTAR's failure to prepare properly for the scope of the work required to properly adjust the settings of the protection system devices to not trip within the "no trip zone" of PRC-024 R2, Attachment 2 and therefore had to have third party consultants perform the verifications and adjustments after the mandatory and enforceable date of the Standard. WECC determined that this issue began on July 1, 2016, when the Standard became mandatory and enforceable and ended on March 2, 2018, when third-party consultants adjusted generator protective relay settings changes within the "no trip zone" for a total of 610 days of noncompliance.
Risk Assessment	WECC determined that this issue posed a minimal risk and did not pose a serious and substantial risk to the reliability of the Bulk Power System (BPS). In this instance, WSTAR failed to set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 R2, Attachment 2. Such failure could potentially result in the premature tripping of the generating units offline due to a voltage excursion within the "no trip zone." WSTAR owns and operates 60 individual 2 MW wind turbines that is considered a dispersed generating Facility of 120 MW, applicable to this issue. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as negligible. WSTAR had weak controls in place to prevent or detect the noncompliance. However, the Facility operated at a 28% capacity factor in 2016, which is likely typical for most years. It has not tripped due to voltage relay settings in the experience of WSTAR. These factors tend to reduce the likelihood of an unanticipated loss of the generation. In addition, since wind generation is a variable resource, it is planned and operated with the understanding that it might not always be available, thus decreasing the risk of its loss. Based on this, WECC determined that there was a remote likelihood of causing negligible harm to the BPS. No harm is known to have occurred. WECC determined that WSTAR has no relevant compliance history for this noncompliance. The specific adjustments to Windstar's voltage relay settings are found below: Windstar 1&2 As found As Left GE-C70 27-1 (Level 1 Undervoltage Pickup) 0.7 p.u / 1 sec 0.7 p.u / 2.1 sec SEL-351 27-1 (Level 1 Undervoltage Pickup) 0.693 p.u / 1 sec 0.693 p.u / 2.1 sec SEL-351 27-1 (Level 1 Undervoltage Pickup) 0.693 p.u / 1 sec 0.693 p.u / 2.1 sec
Mitigation	WSTAR submitted a Mitigation Plan to address its issue and WECC accepted WSTAR's Mitigation Plan. To remediate and mitigate this issue, WSTAR: a. hired third-party consultants to perform verifications of the protective relay settings; b. implemented recommended generator protective relay setting changes; c. created an internal system to trigger verification testing of equipment settings.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017121	PRC-024-2	R2	Windstar Energy, LLC (WSTAR)	NCR11292	7/1/2016	6/5/2018	Self-Certification	Completed OR Expected Date 6/22/2018
			WSTAR submitted a Mitigation Plan Completion Certification and WECC verified WSTAR's completion of Mitigation Plan.					

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
FRCC2019021304	PRC-026-1	R1.	Gainesville Regional Utilities (GRU)	NCR00032	1/1/2019	3/15/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed noncompliance.)	On April 8, 2019, GRU submitted a Self-Report stating that, as a Planning Authority, it was in noncompliance with PRC-026-1 R1. This noncompliance started on January 1, 2019, when GRU failed to include all required BES Elements in its Generator Owner and Transmission Owner notification and ended on March 15, 2019 when an amended notification was made. Specifically, GRU made notifications on December 12, 2018, indicating that no BES Elements met the R1 criteria; however, it was later determined that the content of this notification was not correct. On February 26, 2019, during a planner training session, GRU's Transmission planning engineer discovered an error in the interpretation of the 2017 and 2018 Extreme Event Planning Assessments. There were three (3) scenarios where relay tripping occurred due to a stable or unstable power swing during a simulated disturbance (R1 criteria 4), totaling six (6) BES Elements for all simulations. The cause for this noncompliance was insufficient internal controls to prevent improper interpretation of simulation results.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk was reduced because the delay in notifying the Generation Owner and Transmission Owner of applicable BES Elements was minimal (73 days) and the relay tripping in question (criteria 4) involved only simulated extreme events. GRU has a peak load of 483 MWs which represents .94% of the Region and a total generation output of 521 MWs representing 0.96% of the Region. The Region determined that the Entity's compliance history should not serve as a basis for applying a penalty. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, GRU: 1) perform extent of condition assessment back to 1/1/2018; 2) performed a cause analysis; 3) established procedure for PRC-026-1 assessment, peer review, and notification; and 4) trained all applicable personnel on procedure.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
FRCC2019021398	TPL-007-1	R5. 5.1.	Tampa Electric Company (TEC or the Entity)	NCR00074	1/1/2019	3/6/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed noncompliance.)	On April 24, 2019, Entity submitted a Self-Report stating that, as a Transmission Planner and Planning Authority, it had an issue of TPL-007-1 R5. This noncompliance started on January 1, 2019, when TEC failed to provide the required Entities with flow information as required and ended on March 6, 2019, when TEC completed the proper notifications. This noncompliance involves an administrative lapse that resulted in a 64-day delay in formally communicating geomagnetically-induced current (GIC) flow information to each Generator Operator (GO) within TEC's planning area. The Entity discovered the deadline to communicate GIC flow information had passed during an internal evidence review of requirement R5 on March 5, 2019. TEC subsequently corrected the problem by communicating the GIC flow information to the GOs on March 6, 2019. TEC's Transmission Planning (TP) department received the GIC flow study results on December 5, 2018. The study results include GIC flow information for the entire FRCC region. The task of extracting GIC flow information for the planning area from the overall study results and communicating that information to the GOs was assigned to a supervisor. The supervisor created a Microsoft Outlook Task to complete this work by December 28, 2018. However, the Outlook tool created to track the compliance of requirement R5 and R5.1 was incorrectly set up and did not alert the employee as the due date approached. An extent of condition was performed, and no additional instances of noncompliance were found related to this issue. The cause for this noncompliance was an incorrect use of the Outlook tool by the supervisor tasked with communicating the GIC flow information to the GOs within the planning area.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the BPS. The risk of not providing flow information to the required GOs could cause the performance of individual transformer thermal assessments to be incorrect leading to equipment damage should a geomagnetic disturbance occur impacting the BPS. This risk is reduced because the impact of any potential geomagnetic disturbance in the FRCC Region is extremely low. It was further reduced in this instance because although the GOs need GIC flow information to determine whether they are required to perform individual transformer thermal assessment, none of the transformers in TEC's planning area exceeded the 75A/phase threshold that would trigger the requirement for an individual thermal assessment. In fact, the highest GIC level of any transformer in TEC's planning area was 6.097A or only about 8.1 percent of the threshold. The Region determined that the Entity's compliance history should not serve as a basis for applying a penalty. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, the Entity: 1) sent email to the GOs; 2) determined extent of condition; 3) performed a root cause analysis; 4) updated Transmission Planning Procedures; 5) conducted annual training on revised Transmission Planning Procedures; 6) implemented monthly lookahead on Transmission Planning NERC Deliverables; and 7) reviewed the task feature in Outlook.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020122	TOP-002-4	R1	American Transmission Co. LLC (ATC)	NCR00685	2/13/2018	4/27/2018	self-log	6/28/2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 13, 2018, ATC submitted a self-log stating that as a Transmission Operator, it was in noncompliance with TOP-002-4 R1. ATC is registered in the ReliabilityFirst (RF) Region under the same name and NCR ID, and both are monitored under the Coordinated Oversight Program. The noncompliance impacted both Regions. Specifically, ATC created a new Division (a geographical area comprised of the Upper Peninsula of Michigan) in the EMS application and relocated all EMS modeled BES Facilities in that geographical area to the new Division. ATC states the creation of the new Division was done to align with changes ATC's Balancing Authority made. However, during this relocation process, ATC failed to include the BES Facilities from the Division in ATC's EMS modeling database that is used to perform Operational Planning Analysis. This Analysis determines if its planned operations would exceed any System Operating Limits (SOLs). The noncompliance affected the BES assets in the new Division (approximately 4% of ATC's BES Facilities) and did not affect ATC's Operational Planning Analysis for the other BES Facilities. The cause of the noncompliance was that ATC did not have sufficient controls (such as procedural documentation or peer review) to ensure that EMS model updates were performed accurately. This noncompliance started on February 13, 2018, when ATC made the error that prevented Operational Planning Analysis from being performed in the Division and ended on April 27, 2018, when the model errors were corrected and Operational Planning Analysis was conducted for the Division.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The BES Assets were located within ATC's Reliability Coordinator's (RC) footprint; ATC states that its RC performed a Real-time Assessment (RTA) of the RC's footprint at least once every 30 minutes during the noncompliance. Further, ATC reports that it has two Remedial Action Schemes (RAS) in the Division, the two RAS were designed to detect abnormal system conditions and take corrective actions, and the noncompliance did not impact that capability. Finally, ATC did not identify a contingency that met the RC's criteria for an Interconnection Reliability Operating Limit (IROL) during the noncompliance and ATC states that a significant event in the Division could only be caused by several forced outages. No harm is known to have occurred. There is little risk of recurrence during the completion of mitigating activities. Modeling changes such as these are infrequent with ATC stating this was the first change completed under its current EMS software. Additionally, this occurrence and the investigation into it, raised awareness in applicable staff.
Mitigation	To mitigate this noncompliance, ATC: 1) corrected the area modeling database errors in the EMS; 2) conducted interviews to determine if there was other similar noncompliance; and 3) completed a third-party assessment of the cause and scope of the events that lead to the noncompliance. To mitigate this noncompliance, ATC will: 1) develop guidance documentation to be used during any EMS modeling changes and other related activities; and 2) provide training to relevant staff on the guidance documentation. The length of the mitigating activities is related to the sequencing of the events and that the development of guidance documentation is a collaborative and deliberative process.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020123	TOP-001-3	R13	American Transmission Co. LLC (ATC)	NCR00685	2/13/2018	4/27/2018	self-log	6/28/2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 13, 2018, ATC submitted a self-log stating that as a Transmission Operator, it was in noncompliance with TOP-001-3 R13. ATC is registered in the ReliabilityFirst (RF) Region under the same name and NCR ID, and both are monitored under the Coordinated Oversight Program. The noncompliance impacted both Regions. Specifically, ATC created a new Division (a geographical area comprised of the Upper Peninsula of Michigan) in the EMS application and relocated all EMS modeled BES Facilities in that geographical area to the new Division. ATC states the creation of the new Division was done to align with changes ATC's Balancing Authority made. However, during this relocation process, ATC failed to include the BES Facilities in ATC's EMS modeling database that is used to support ATC's Real-time Assessment (RTA). The cause of the noncompliance was that ATC did not have sufficient controls (such as procedural documentation or peer review) to ensure that EMS model updates were performed accurately. This noncompliance started on February 13, 2018, when ATC made the error that prevented a complete RTA from being performed and ended on April 27, 2018, when the model errors were corrected and a complete RTA was performed.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The BES Assets were located within ATC's Reliability Coordinator's (RC) footprint; ATC states that its RC performed a RTA of the RC's footprint at least once every 30 minutes during the noncompliance. Further, ATC states that its monitoring of stability rating limits was unaffected by the noncompliance. ATC reports that it has two Remedial Action Schemes (RAS) in the Division, the two RAS were designed to detect abnormal system conditions and take corrective actions, and the noncompliance did not impact that capability. Finally, ATC did not identify a contingency that met the RC's criteria for an Interconnection Reliability Operating Limit (IROL) during the noncompliance and ATC states that a significant event in the Division could only be caused by several forced outages. No harm is known to have occurred. There is little risk of recurrence during the completion of mitigating activities. Modeling changes such as these are infrequent with ATC stating this was the first change completed under its current EMS software. Additionally, this occurrence and the investigation into it, raised awareness in applicable staff.
Mitigation	To mitigate this noncompliance, ATC: 1) corrected the area modeling database errors in the EMS; 2) conducted interviews to determine if there was other similar noncompliance; and 3) completed a third-party assessment of the cause and scope of the events that lead to the noncompliance. To mitigate this noncompliance, ATC will: 1) develop guidance documentation to be used during any EMS modeling changes and other related activities; and 2) provide training to relevant staff on the guidance documentation. The length of the mitigating activities is related to the sequencing of the events and that the development of guidance documentation is a collaborative and deliberative process.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2017017056	PRC-006-2	R9	Northern States Power (Xcel Energy) (NSP)	NCR01020	10/1/2015	6/28/2016	Self-Certification	Completed
Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 30, 2016, NSP, a Coordinated Oversight Program participant, submitted a Self-Certification to MRO stating that, as a Transmission Owner, it was in noncompliance with PRC-006-2 R9. NSP, Public Service Company of Colorado (PSCO) (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program. The noncompliance occurred in the operating area of NSP. Xcel Energy states that it discovered relays that were not set correctly during sampling for the Self-Certification. A comprehensive review of all NSP UFLS relay settings discovered a total of 73 UFLS relays that were not set according to the documented UFLS Plan. Xcel Energy reports that this caused NSP's load shed for the 59 Hz UFLS step to be 9.7%; this is .3% below the 10% minimum specified by the UFLS program. Xcel Energy states that the 59.3 and 58.7 Hz UFLS steps were not impacted by the noncompliance. The noncompliance was caused by a lack of clarity in the UFLS Program and ineffective controls for the implementation of the UFLS Program. This noncompliance started on October 1, 2015, when the standard became mandatory and ended on June 28, 2016 when the settings were corrected.							
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The noncompliance translated into a shortfall of .3% of load at one UFLS step; this translates to approximately 30 MW of load. MRO determined that this small fluctuation is consistent with the normal variations in load distribution and broad assumptions used in the development of a UFLS program. No harm is known to have occurred. Xcel Energy has no relevant history of noncompliance.							
Mitigation	To mitigate this noncompliance, Xcel Energy: 1) investigated all UFLS circuits to verify the frequency to which the relays are set; 2) adjusted the load to be shed to ensure that at least 10% of system load is shed at 59 Hz; and 3) received an updated UFLS Program from its Planning Coordinator that provided improved clarity and established upper and lower UFLS limits. The mitigation was limited to the NSP system.							

NERC Noncompliance ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Mitigation Completion Date
NPCC2018020724	MOD-025-2	R2	Wallingford Energy LLC (Wallingford)	NCR11102	07/01/2018	07/25/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 21, 2018, Wallingford Energy LLC ("the Entity") submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2, R2. The Entity did not complete the verification of its Reactive Power capability of its applicable Facilities in accordance with the MOD-025-2 Implementation Plan. The Entity needed to have verification of Reactive Power capability (testing) completed on 4 out 5 (80%) of its generating units by July 1, 2018. Instead, the Entity verified Reactive Power capability was completed on only 3 units (60%). The Entity completed the verification of Reactive Power capability of a fourth unit on July 25, 2018. The noncompliance was discovered during a review of relevant evidence during audit preparation for Wallingford Energy's 2018 O&P off-site audit. This noncompliance started on July 1, 2018 and ended on July 25, 2018 when testing on the 4th unit was completed and the results provided to the Transmission Planner. The root cause of this noncompliance was lack of management oversight and focus to complete the testing to reach 80% on the existing units. Instead, Wallingford resources were focused on the commissioning of new units 6 and 7 that were coming online in May 2018. Due to the unusual level of activity, resource commitment, and focus on the new unit development and implementation, the testing and verification on at least one more of the existing applicable Facilities was not performed by July 1, 2018. Additionally, the Entity submitted a request to perform testing in February 2018 that was denied by the ISONE because the request did not meet the ISONE scheduling guidelines and the subsequent follow-up to reschedule the test did not occur.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The potential risk due to this noncompliance is the Transmission Planner having inaccurate information about the generating units when developing planning models to assess BPS reliability. However, the Entity's applicable facilities consist of five 51MW units had always participated in ISONE historical reactive capability testing before MOD-025-2 came into effect. The plant had a 2017 capacity factor of 6.7 % and a 2016 capacity factor of 10.7%. The rated capability of each of the units is about 2.2 % of the ISONE typical required Operating Reserve (approximately 2,300 MW). The required testing was completed approximately three weeks later than required so the exposure time was relatively short and the unit's reactive capabilities were already well established and documented with their Planning Coordinator and Transmission Planner, ISONE. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Wallingford Energy: 1) Completed the testing on both untested units and provided the results to the Transmission Planner. 2) Implemented a compliance software tool as an internal control that will track all dates and obligations for NERC Standards that will initiate advanced notifications and follow up notices to managers as dates approach and will require maintenance activities to be closed in the system. The notifications in the tool are to the plant and a 3rd party consultant.

NERC Noncompliance ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Mitigation Completion Date
NPCC2018020870	PRC-019-2	R1	Wallingford Energy LLC (Wallingford)	NCR11102	05/09/2018	08/16/2018	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	During a Compliance Audit conducted from October 1, 2018 through December 20, 2018, NPCC determined that Wallingford Energy LLC ("the Entity"), as a Generator Owner, was in noncompliance of PRC-019-2, R1. The Entity failed to coordinate the voltage regulating system controls with the applicable equipment capabilities and setting of the applicable Protection System devices and functions for new units 6 and 7 which were both synchronized to the grid on May 9, 2018. The noncompliance started on May 9, 2018, when units 6 and 7 first synchronized to the grid and ended on August 16, 2018 when the verification of the coordination was completed. The root cause of this PRC-019-2 noncompliance was a lack of understanding where it was believed by management that PRC-019-2 Implementation Plan allowed a one year grace period to verify the coordination of new units 6 and 7.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The failure to verify the coordination of the protection system with the in-service limiters could cause an unnecessary trip, or failure to trip of the unit, which could stress the system further. However, the Entity's applicable Facilities consist of the two 51 MW units. The plant had a 2017 capacity factor of 6.7 % and a 2016 capacity factor of 10.7%. The rated capability of each of the units is about 2.2 % of the ISONE typical required Operating Reserve (approximately 2,300 MW). The combined capability of Units 6 and 7 would be about 4.4 % of the ISO-New England typical operating reserve level. ISO-New England would be able to obtain that amount of replacement operating reserve. The required testing was completed approximately three months after initial synchronization so the exposure time was relatively short. There were no settings changes or adjustments that were discovered to be needed once the entity completed its coordination review. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Wallingford Energy: 1) Completed the necessary coordination of voltage system regulating controls with protection systems for the new units 6 and 7. 2) Implemented a compliance software package as an internal control to include tracking and documentation of dates when testing, equipment setting changes and control settings are made and coordinated to meet NERC standard requirements and milestone dates so that advanced electronic automatic notifications are made to plan for and conduct necessary testing. The notifications in the tool are to the plant and the 3rd party NERC consultant.

NERC Noncompliance ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Mitigation Completion Date
NPCC2018020871	PRC-024-2	R2	Wallingford Energy LLC (Wallingford)	NCR11102	05/09/2018	08/16/2018	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	During a Compliance Audit conducted from October 1, 2018 through December 20, 2018, NPCC determined that Wallingford Energy LLC ("the Entity"), as a Generator Owner, was in noncompliance of PRC-024-2, R2. The Entity failed to properly set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2. More specifically, the Entity failed to properly set the volts/hz relays on new units 6 and 7 prior to both of them synchronizing to the grid on May 9, 2018. During a review of audit evidence, NPCC discovered that information contained in a generator protection testing report from relay testing that was completed on August 16, 2018 indicated that the Entity unknowingly had the volts/hz relay settings inside the Attachment 2 no trip zone since May 9, 2018. The relay test report reviewed by NPCC during the Compliance Audit was developed as a result of the units tripping off (while online as a test unit and while not participating in the ISONE market) due to volts/hz relay action during July 2018 reactive commissioning testing. The noncompliance started on May 9, 2018 and ended on August 16, 2018 when all of the settings were confirmed to meet the performance characteristics of the Attachment 2 curve. The root cause of this PRC-024-2 noncompliance was a lack of understanding where it was believed by management that PRC-024-2 Implementation Plan allowed a one year grace period to verify and meet the performance characteristics of new units 6 and 7 to Attachment 2..
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Noncompliance with PRC-024-2 R2 could result in trips that occur when they should not and capacity loss during a system voltage excursion event, which would further stress the system during a contingency. However, the Entity applicable Facilities (new units 6 and 7) consist of two 51MW units. The plant had a 2017 capacity factor of 6.7 % and a 2016 capacity factor of 10.7%. The rated capability of each of the units is about 2.2 % of the ISONE typical required Operating Reserve (approximately 2,300 MW). The combined capability of Units 6 and 7 would be about 4.4 % of the ISO-New England typical operating reserve level. ISONE would be able to obtain that amount of replacement operating reserve. The required testing was completed approximately three months after initial synchronization so the exposure time was relatively short. The entity adjusted the V/Hz settings on both of the redundant microprocessor relays that are associated with unit 6 and unit 7. The undervoltage and overvoltage settings on both of the redundant microprocessor relays were already correct for both unit 6 and unit 7. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Wallingford Energy: 1) Completed a review of all protective relaying associated with units 6 and 7 to ensure that they meet the performance characteristics of Attachment 2. 2) Implemented a compliance software package as an internal control to include tracking and documentation of dates when testing, equipment setting changes and control settings are made and coordinated to meet NERC standard requirements and milestone dates so that advanced electronic automatic notifications are made to plan for and conduct necessary testing. The notifications in the tool are to the plant and the 3rd party NERC consultant.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020404	PRC-001-1.1(ii)	R3	Lakewood Cogeneration, LP	NCR00168	3/9/2017	8/10/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On September 7, 2018, the entity submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with PRC-001-1.1(ii) R3 because it made relay setting changes prior to notifying, and coordinating with, its Transmission Operator. More specifically, the entity changed the 21G Impedance Relay and 51V Voltage Controlled Overcurrent Relay settings. The changes were implemented in an effort to comply with PRC-025. The root cause of this noncompliance was a lack of effective controls and processes, including ineffective supervision of, and inadequate communications regarding, relay setting changes. This noncompliance implicates the management practices of workforce management and planning. Effective workforce management can minimize the frequency and consequences of events relating to bulk electric system (BES) reliability and resilience and can be achieved, in part, through the development and implementation of clear and executable processes and procedures. And, an entity should strive to avoid unplanned and uncoordinated work, which can produce unintended and undesirable consequences affecting BES reliability and resilience. This noncompliance started on March 9, 2017, when the entity completed the relay setting changes and ended on August 10, 2018, after the entity communicated and coordinated the changes with its Transmission Operator.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. Failing to coordinate protective system changes with a Transmission Operator could result in inadequate protection for interconnected assets, unexpected tripping, misoperation, or a system event. The risk was mitigated by the following facts. First, the changes were implemented in an effort to comply with PRC-025 and were designed to improve the performance of the system under abnormal or emergency conditions and prevent cascading failures. Second, the changes were in place for approximately one-and-one-half years without causing any issues. Third, these types of changes do not occur frequently, and therefore, this issue is unlikely to occur again. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) developed a change management process to address how facility changes need to be addressed via the NERC standards; 2) reviewed the PRC-001 plant procedure to ensure it properly addresses the required notifications for relay setting changes and, if required, agreed to update the procedure; and 3) retrained staff on what needs to occur prior to changing settings. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019897	EOP-004-2	R3	LSP University Park, LLC	NCR11107	7/1/2016	12/31/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On June 6, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with EOP-004-2 R3. On January 1, 2018, IHI Power Services Corporation (IPSC) took over control of plant operations and NERC compliance at the University Park North (UPN) facility. As part of this change, IPSC performed a baseline review of NERC compliance in place at the time of the change. As part of this review, IPSC discovered that it could not locate documentation to verify that the contact information was validated in 2016 and 2017. IPSC conducted interviews with employees who had worked at the plant in 2017. Those individuals confirmed that the validation was completed in 2017, but just not documented properly. The root cause of this noncompliance was the lack of effective internal controls to ensure the validation task was properly completed and documented each year. This major contributing factor involves the management practice of reliability quality management, which includes maintaining a system for identifying and deploying internal controls. This noncompliance started on July 1, 2016, when the entity was required to have validated the contact list and ended on February 20, 2018, when the entity validated the contact list for 2018.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The potential risk associated with failing to annually validate the contact information in the Operating Plan is that notification to these parties could be delayed due to outdated or inaccurate information. This risk was mitigated in this case by the following factors. First, UPN personnel stated that they validated the contact information in 2017, but that they just failed to document it appropriately. Second, the entity's statement that this is merely a documentation issue is supported by the fact that when IPSC performed the validation in 2018, the contact information was all still valid. ReliabilityFirst also notes that during the time of the noncompliance, no events requiring contact occurred. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) validated all contact information contained in the Operating Plan pursuant to Requirement 1; and 2) developed a preventive maintenance activity to require completion of the verification annually going forward. This preventive maintenance includes a requirement to store the verification documentation in a SharePoint site to ensure the records will not be lost in the future. The Preventive Maintenance cannot be closed until this activity has been completed.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019902	MOD-032-1	R2	LSP University Park, LLC	NCR11107	7/1/2016	6/15/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On June 6, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-032-1 R2. On January 1, 2018, IHI Power Services Corporation (IPSC) took over control of plant operations and NERC compliance at the University Park North (UPN) facility. As part of this change, IPSC performed a baseline review of NERC compliance in place at the time of the change. As part of this review, IPSC discovered that the entity failed to transmit the modeling data specified in Requirement 2 to PJM by July 1, 2016, the date specified in the implementation plan. IPSC obtained confirmation from PJM that this modeling data was not submitted until 2017. The root cause of this noncompliance was the lack of effective internal controls to ensure the modeling data was transmitted to PJM on time. This major contributing factor involves the management practice of reliability quality management, which includes maintaining a system for identifying and deploying internal controls. This noncompliance started on July 1, 2016, when the entity was required to send the modeling data to PJM and ended on June 15, 2017, when the entity actually sent the modeling data to PJM.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The potential risk associated with failing to timely submit modeling data to PJM is that the data used in PJM's models could be incorrect, impacting the accuracy of the models. This risk was mitigated in this case by the following factors. First, the modeling data had not changed from what PJM already had in its possession. Therefore, the late transmittal had no effect on the accuracy of PJM's model. Second, the entity transmitted the modeling data less than a year late, which limits the amount of time that PJM's model could have been inaccurate or out-of-date. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) reviewed and submitted 2018 MOD-032-1 R2 data to PJM; and 2) created an Annual MOD-032 data submittal Preventive Maintenance Work Order to ensure timely transmittal of the data in the future.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019899	PRC-019-2	R1	LSP University Park, LLC	NCR11107	7/1/2016	8/31/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On June 6, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2 R1. On January 1, 2018, IHI Power Services Corporation (IPSC) took over control of plant operations and NERC compliance at the University Park North (UPN) facility. As part of this change, IPSC performed a baseline review of NERC compliance in place at the time of the change. As part of this review, IPSC discovered that, while the entity performed the required coordination study in June 2016, it failed to take action to make necessary changes. Specifically, in regard to PRC-019-2, R1.1.1, the study found that relay limiters were set to operate at values higher than their associated protection relays set points. Therefore, they were not coordinated properly. The errant components included the Volts-to-Hertz relay and the Phase-Undervoltage relay. The root cause of this noncompliance was the lack of effective internal controls to ensure that appropriate action was taken after the PRC-019 study was completed. This major contributing factor involves the management practice of reliability quality management, which includes maintaining a system for identifying and deploying internal controls. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-019-2 R1 and ended on August 31, 2018, when the entity completed work necessary to ensure proper coordination.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The potential risk posed by failing to properly coordinate these devices is that the relays could operate before the limiters causing an early or unexpected trip. This risk was mitigated in this case by the following factors. First, the units were capable of controlling voltage to the degree permitted by the trip set points of the relays without damage to the facility or the grid. Second, the units are small peaking units, and, typically, only a few are operated at a time. ReliabilityFirst also notes that no early trips occurred due to the limiters not being set to operate prior to the protective relays. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity modified errant relay setpoints and verified that all PRC-019 requirements are satisfied. The entity developed a Preventive Maintenance work order requiring the completion of the PRC-019-2 on a five-year review cycle.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019900	PRC-024-2	R1	LSP University Park, LLC	NCR11107	7/1/2016	5/29/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On June 6, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R1. On January 1, 2018, IHI Power Services Corporation (IPSC) took over control of plant operations and NERC compliance at the University Park North (UPN) facility. As part of this change, IPSC performed a baseline review of NERC compliance in place at the time of the change. As part of this review, IPSC discovered that, while the entity performed the required PRC-024 evaluation in 2016, some questions coming out of that evaluation were not resolved completely. Specifically, IPSC could not locate any documentation verifying that the frequency trips for units 2, 3, 4, and 12 were conclusively outside the no trip zone. The root cause of this noncompliance was the lack of effective internal controls to ensure that appropriate action was taken after the PRC-024 evaluation was completed. This major contributing factor involves the management practice of reliability quality management, which includes maintaining a system for identifying and deploying internal controls. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R1 and ended on May 29, 2018, when the entity completed its Mitigation Plan.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The potential risk posed by failing to ensure that the frequency trips are outside of the no trip zone is that the units could be tripped early and not available to provide frequency support when necessary. This risk was mitigated in this case by the fact that the units are small peaking units, and, typically, only a few are operated at a time. ReliabilityFirst also notes that the units have not experienced any early trips due to the present settings of the relays. Furthermore, when running at full load, each of the 12 units contributes approximately 45 MW to the grid and operated at average 12.26% capacity factor for the duration of the noncompliance. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity evaluated and verified the frequency trips for units 2, 3, 4, and 12 are outside the no trip zone. As an additional mitigating action, the entity reviewed and updated its internal compliance program to ensure that the frequency set points will not be changed without appropriate approvals. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020502	MOD-027-1	R2	Northern Indiana Public Service Company LLC (NIPSCO)	NCR02611	July 1, 2018	July 23, 2018	Self-Report	April 30, 2019

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On October 2, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-027-1 R2. On April 11, 2018, the entity contracted with General Electric (GE) to perform the required MOD-027 verification testing. MOD-027-1 R2 required that 30% of the entity generation fleet have verification testing completed by July 1, 2018. The entity scheduled GE to conduct the verification testing at Michigan City Unit 12 and Schaffer Unit 15, and to submit a final report to the entity for Schaffer Unit 15. GE designated a GE employee to perform the testing. The GE employee informed the entity that the necessary work would be completed in time to comply with MOD-027-1 R2. On April 13, 2018, GE informed the entity that the GE employee designated to perform the testing had resigned. Approximately a month later on May 16, 2018, a GE supervisor informed the entity that he would perform the test and submit the report to the entity. On May 24, 2018, GE completed the testing at Schaffer Unit 15, and the raw test data was made available at that time. The final analysis and report, however, with verified models sent to the Transmission Planner, were not completed until July 23, 2018. This delay resulted in the entity not completing testing on 30% of its fleet by the due date of July 1, 2018. (31.9% based on Nameplate MVA.) This noncompliance involves the management practices of external interdependencies and verification. External interdependencies is involved because GE did not complete all of its contracted work until after the July 1, 2018 implementation date. The entity did not specify in the contract the actual due date for all work to be completed including submission of the final report and that mistake is a root cause of this noncompliance. Verification is involved because the entity did not verify that the final analysis and report would be completed, with verified models sent to the Transmission Planner, by the July 1, 2018 implementation date. This noncompliance started on July 1, 2018, when the entity was required to comply with MOD-027-1 R2 and ended on July 23, 2018, when the entity completed the final analysis and report and sent verified models to the Transmission Planner.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS) based on the following factors. The risk posed by this noncompliance arises from allowing dynamic simulations that assess BPS reliability to inaccurately represent generator unit real power response to system frequency variations. That can lead to planning and operating the BPS with inaccurate information. The risk is minimized because the entity completed verification testing on 30% of the entity generation fleet just 22 days late and no changes were required. Additionally, the entity had contracted with GE to complete all required verification testing in advance of the July 1, 2018 implementation date, but GE did not complete the required verification testing on time. The entity had planned and taken all necessary actions to become compliant with MOD-027-1 R2 as of July 1, 2018 and was only overdue in its compliance due to GE's delays in completing the final analysis and report. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity will complete the following mitigation activities by April 30, 2019: 1) developed a Power Point slide deck on the MOD-027 requirements to be delivered to the Generator Owner (GO) personnel; 2) delivered MOD-027 training to the relevant GO personnel. This training informed personnel of what their responsibilities are for maintaining compliance with MOD-027; 3) scheduled touchpoints (GO Touchpoint 1) with the entity's Station Engineering and Maintenance Department to track their progress on future MOD-027 milestones; and 4) will schedule touchpoints (GO Touchpoint 2) with the entity's Station Engineering and Maintenance Department to track their progress on future MOD-027 milestones. The entity needs until April 30, 2019 to complete mitigation because of training timing.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019983	PRC-005-2	R3	Talen Generation, LLC (Talen)	NCR11362	4/1/2015	3/9/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On July 2, 2018, Talen submitted a Self-Report on behalf of Nueces Bay WLE LP (NCR04106), Laredo WLE LP (NCR04090), Barney M Davis LP (NCR04009), and Barney M Davis Unit 1 (NCR04010), stating that, as a Generator Owner, it was in noncompliance with PRC-005-2 R3. Talen submitted the Self-Report to ReliabilityFirst under an existing multi-region registered entity agreement. The entity owns a variety of plants in Texas that are known as the Topaz Fleet. The Topaz Fleet consists of four plants: Nueces Bay WLE LP (Nueces Bay), Laredo WLE LP (Laredo), Barney M Davis LP (Barney Davis), and Barney M Davis Unit 1 (Barney Davis 1). During an annual review, the entity discovered that historical battery maintenance and testing evidence did not clearly document all PRC-005 related compliance requirements at two of the four plants. After this discovery, the entity further reviewed the battery maintenance and testing evidence and found noncompliances at all four plants. The entity's review discovered that monthly maintenance and testing did not clearly document a total of 47 required maintenance and testing activities across the four plants. More specifically, the following checks on the plants' battery banks were not clearly documented: (a) 8 electro level inspections, (b) 16 unintentional grounds, (c) 9 battery rack inspections, and (d) 14 battery terminal connection resistance reviews. (For battery terminal connection resistance testing, the contractor made measurements using an instrument that produced a standardized printout showing resistance for all straps, but for just one of the two end-connections.) The entity contracts with a third party to perform its PRC-005 battery testing and maintenance. All of the reports that the entity reviewed are automatically produced by the test equipment used by the contractor. This noncompliance involves the management practices of external interdependencies and verification. External interdependencies is involved because the contractor's battery test form templates did not clearly define tasks and did not provide the documentation the entity needed to demonstrate compliance with PRC-005. A root cause is the incorrect test form templates. Verification is also involved because the entity did not verify that the reports generated by the contractor included all of the required information. This noncompliance started on April 1, 2015, when the entity was required to comply with PRC-005-2 R3 and ended on March 9, 2018, when the entity completed its Mitigating Activities.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this noncompliance is that the generating units are protected by various components, one of which is the battery system. If the battery systems failed, the Protection System may fail and equipment may be damaged if there was a fault. (The four plants involved in this noncompliance combined have a total capacity of ~2400 MVA nameplate.) The risk is minimized because the Topaz facilities exercise good operating practices including twice daily rounds reviewing each battery system (via visual inspections) and Distributed Control System (DCS) alarms for all battery systems. (Barney Davis 1 does not have an alarm system.) These daily rounds increase the likelihood that the entity would discover an issue with any of its batteries. The Topaz facilities also completed all other PRC-005 required maintenance and testing. Lastly, the risk is reduced because the likelihood of generation loss (the potential harm) is low. As an additional note, the entity believes, based off of communications with its contractors and its plant staff, that all of the maintenance activities were being done, but they were not properly documented because the forms being used were either not detailed enough, or lacked specific fields to document all of the mandatory tests. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) issued new battery form templates that define tasks and clearly document results; and 2) utilized the fleet wide battery test form templates at all four plants (replacing the incorrect contractor form templates) and the plants have provided the final testing reports. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020209	COM-002-4	R4	Wolverine Power Supply Cooperative, Inc. (Wolverine)	NCR00954	7/1/2016	9/10/2018	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On August 2, 2018, during a Compliance Audit conducted from July 17, 2018, through July 18, 2018, ReliabilityFirst determined that the entity, as a Transmission Operator, was in noncompliance with COM-002-4 R4. To assess adherence to its documented communication protocols, the entity listens to tapes of relevant communications and completes evaluation forms that include the criteria that must be met. These criteria include not only the basic three-part communications protocols contained in COM-002-4 R1, but also some additional details, such as using names, etc. The entity provided 12 of these evaluation forms to ReliabilityFirst during the audit. However, issues were present with 11 of these 12 forms. Four of the forms were mismarked, indicating that proper three-part communication had not been performed. However, the entity pulled the tapes and found that proper three-part communication had occurred. (The entity undertook this effort at the request of the audit team.) The other 7 forms noted that other criteria, not related to three-part communication, was missing in the communication. Additionally, the entity indicated that its process was to provide feedback to employees. However, none of the 12 forms contained any feedback. The root cause of this noncompliance was insufficient training in task performance and communication techniques. This root cause involves the management practice of workforce management, which includes providing training, education, and awareness to employees. This noncompliance started on July 1, 2016, when the entity was required to comply with COM-002-4 R4 and ended on September 10, 2018, when the entity completed its Mitigation Plan.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by failing to properly assess adherence to communication protocols is that the responsible entity would not know whether its communication protocols were being properly implemented, resulting in ineffective communications essential to the reliable operation of the BPS. This risk was mitigated in this case by the following factors. First, ReliabilityFirst noted that it reviewed the training records of relevant employees and concluded that they were adequately trained in 3 part communication (and this supported the findings from the tape reviews that proper three-part communication occurred). The evidence to support this finding included signed training class logs and signed test documentation. Second, the entity had designed an internal control (i.e., the evaluation forms), and although the entity did not complete all of the forms correctly, the control was designed to provide feedback on how well its communication protocols were being implemented, thus providing the opportunity to improve performance and ensure alignment with goals and strategies. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) reviewed protocol for deficiencies, and made preliminary edits; 2) reviewed Power Point training for deficiencies, and made edits. The entity reviewed protocol for deficiencies, understanding of appendix (evaluation), and made edits. (Edits of the communication protocol include (a) a multi-tiered approach to assessing adherence to the protocol to minimize errors; (b) clarified instructions to drive more accurate completion of the assessment forms; and, (c) instructions for electronically storing completed assessments for better record keeping.); 3) approved and distributed the new Power Point via SharePoint-control environment. The entity will review SharePoint annually for updates as needed; 4) approved and distributed the protocol; 5) implemented the internal control for the assessor; 6) completed the internal control tasks; and 7) assessed each System Operator's performance and adequately addressed any corrective action, coaching, training, feedback. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020378	VAR-002-4.1	R3	Wolverine Power Supply Cooperative, Inc. (Wolverine)	NCR00954	8/28/2018	8/31/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On August 31, 2018, the entity submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with VAR-002-4.1 R3. During the morning of August 28, 2018, a storm caused a number of lightning driven alarms at the Alpine generation facility. These lightning events caused an exciter to trip, which required it to be reset. This trip/reset cycle on the exciter disabled the power system stabilizer (PSS) on Alpine Unit 1. Approximately 12 hours later, the entity discovered that the PSS was disabled and reengaged it. However, the entity did not notify its Transmission Operator (TOP) of the PSS status change until August 31, 2018, in violation of VAR-002-4.1 R3. The root cause of the noncompliance was an insufficient pre-start check process. Because the PSS becomes automatically disabled after the trip/reset cycle on the exciter, the entity should have included an explicit PSS check step in its pre-start check process. A contributing cause was the fact that the PSS status was not configured for an individual alarm in the operator's software system. The root cause involves the management practice of grid operations, which includes defining operating procedures and performing incident management and control. This noncompliance started on August 28, 2018, when the entity was required to have notified its TOP that the PSS was disabled, and ended on August 31, 2018, when the entity actually notified its TOP.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by an entity failing to notify its TOP of a PSS being disabled is that it could make it more difficult for the TOP to maintain system voltage if a power swing occurred on the system. Also, a loss of the generator could occur due to these power fluctuations at the generator. This risk was mitigated in this case by the fact that Unit 1 at the Alpine generation facility runs in parallel with Unit 2. During the period of the noncompliance, Unit 2 was equipped with an automatic voltage regulator and its PSS was engaged, which assisted in voltage control and minimizing the effects of any power swings due to the PSS being disabled on Unit 1. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) notified its TOP of the PSS being disabled; 2) configured a layered-alarm approach in its software suite for system operators; and 3) updated the generation unit pre-start checklist to include an explicit step requiring a check of the PSS.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017017682	PER-005-2	R1	Ameren Services Company (Ameren)	NCR01175	7/1/2016	8/30/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 24, 2017, SERC sent Ameren an audit notification letter notifying it of a compliance audit scheduled for September 11, 2017 through September 15, 2017. On June 2, 2017, Ameren submitted a Self-Report stating that, as a Balancing Authority and Transmission Operator, it was in noncompliance with PER-005-2 R1. Ameren did not have evidence of implementing the systematic approach it used to develop its System Operator training program. On May 5, 2017, during Ameren's internal review of documentation for PER-005-2 R1, Ameren determined that it did not have documentation of the analysis phase of its systematic approach to training process. Ameren's analysis process is to analyze jobs to gain a complete understanding, compile a task inventory of all tasks associated with each job, select tasks that require training, build performance measures for the task training, and choose instructional setting for training. Ameren submitted an attestation stating that it developed the required task list in accordance with its overview process even though Ameren does not have evidence of such. The primary cause of this noncompliance is that Ameren incorrectly believed that it did not need evidence of implementing all requirements of its systematic approach to training process. This noncompliance started on July 1, 2016, when PER-005-2 became mandatory and enforceable, and ended on August 30, 2018, when mitigation was completed.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Ameren's failure to conduct an analysis of the required job responsibilities could result in the System Operator's inability to perform all duties required. However, Ameren states that it did conduct the interviews but it failed to document that the interviews occurred. Ameren states that its System Operators have demonstrated competence in performing all of the tasks required to maintain the reliability of the BPS and the majority of Ameren's System Operators have an average of 21 years as certified Reliability Coordinators. No harm is known to have occurred. SERC considered Ameren's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Ameren: 1) produced a stand-alone procedure as a supplement to the existing overview document that will govern the development and maintenance of Ameren's Systematic Approach to Training (SAT). The SAT includes: a. a detailed instructions for each step, b. a form or template by which steps of the process can be governed to ensure repeatability and consistency (when such steps lend themselves to such a form/template), c. "sign-off" sheets to produce evidence as appropriate when step 2) isn't warranted and d. sufficient instruction and detail relative to contemporaneous, as well as routine, initiation of the Procedure to assure the Ameren Training Plan is current with respect to new or revised real-time reliability tasks. Because the training personnel responsible for executing the PER-005 procedure will develop and document the procedure, training will not be required; 2) implemented procedure and produced documentation of SAT; and 3) Ameren's corporate NERC Compliance department developed an internal standard for what constitutes evidence of NERC compliance for Standards and Requirements that have the "develop and implement" requirement and provide training or a lessons learned to Ameren personnel across the enterprise who are responsible for ensuring compliance with NERC standards.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2016016380	PRC-005-1b	R2	Ameren Missouri (AUE)	NCR10248	1/1/2013	5/25/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 19, 2016, AUE submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-005-1b R2.1. AUE did not complete testing activities for two Protection System relays within the defined program interval. On January 27, 2012, AUE created a work order to retire two relays at its Sioux Energy Center (SEC), one relay on unit 1 and one relay on unit 2. On August 1, 2016, an engineer reviewing protective relaying work for a SEC September outage found both of these relays still in service. AUE investigated and found that it removed the two relays from the maintenance and testing database with the understanding AUE was retiring the relays. However, field crews failed to remove the relays from service. Neither of these relays had tags or markings on them in the field that indicated they were out of service. These two overvoltage time-delay relays were powered and wired into the trip circuit. Because AUE removed the relays from the maintenance and testing database, AUE did not conduct maintenance and testing activities on both relays within the defined interval of six years. AUE removed the unit 1 relay from service on August 25, 2016 and removed the unit 2 relay from service on August 12, 2016. The cause of noncompliance was a communication and process breakdown. On January 27, 2012, AUE issued a job order to retire the relays. Field crews did not act upon the job order from engineering to remove the relays from service because the field crews thought that engineering would also issue removal schematics. Engineers believed the field crews would complete the work with the retirement job order, including marking up drawings, and did not believe removal schematics were required. Based on a note that the relays were retired, AUE closed the job order, and removed the relays from the maintenance and testing schedule without field verification to confirm that field crews removed the relays from service. AUE completed a review of 100% of its PRC-005 applicable devices as part of its mitigation activities. In addition to the two relays out of 695 (0.29%) that AUE identified in the Self-Report, AUE identified eight lockout relays out of 272 (2.9%), all at the Audrain generating station, that were noncompliant starting in 2013 and tested outside of the defined interval. This noncompliance started on January 1, 2013, when AUE exceeded the maintenance and testing interval for the SEC unit 1 relay, and ended on May 25, 2018, when AUE completed testing on the noncompliant relays.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The relays remaining in service and the lockout relays that were not maintained within interval could have tripped off the SEC plant or Audrain generating station. The SEC consists of two coal-fired units with a net generating capacity of 970 MW and the Audrain generating station consists of eight natural gas turbines with a combined capacity of approximately 800 MW. However, AUE's transmission modeling determined the loss of these units would not cause instability to the Bulk Electric System. In addition, AUE determined that no misoperation occurred. Redundant protection schemes were in place together with the SEC relays. At the Audrain generating station, the lockout relays are redundant to each other, requiring failure of both to render the protection incomplete. If neither lockout relay were functional, generator or backup ground overcurrent relaying on the generator step-up transformer would clear the fault. The failure of a single lockout relay would have no impact. No harm is known to have occurred. AUE had relevant compliance history. However, SERC determined that AUE's PRC-005 compliance history should not serve as a basis for applying a penalty because the root cause of the previous noncompliance and the root cause of the instant noncompliance are unrelated. In addition, the mitigating actions and actions to prevent recurrence in the previous noncompliance did not address the cause of the instant noncompliance.
Mitigation	To mitigate this noncompliance, AUE: 1) Conducted a walk down process for all AUE BES generators, which included: a. Verification of physical components against the current drawings. b. Verification that all GO devices to which PRC-005 is applicable were properly identified. c. Verification that all GO devices were in the appropriate maintenance and testing (M&T) database. d. Verification that all required GO M&T activities under PRC-005-1b/2/6 were in the appropriate database with the correct assigned intervals for the applicable version of PRC-005. e. Verification of accurate GO completion documentation of M&T activities as required by PRC-005-1b/2/6 requirements as appropriate. f. Submitted a report to SERC with the results of the above assessment which included: i. The total count of GO devices reviewed by device type ii. A list of all non-compliant GO devices, basis for non-compliance, and the date that the device became non-compliant iii. Apparent cause of the non-compliance iv. Potential and actual risks of non-compliance

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2016016380	PRC-005-1b	R2	Ameren Missouri (AUE)	NCR10248	1/1/2013	5/25/2018	Self-Report	Completed
			g. Brought all non-compliant devices identified during the inventory assessment back into compliance and implemented action items to address the associated cause(s) of the non-compliance. 2) Implemented new internal controls to ensure future compliance with PRC-005-2/6 including any new required GO activities, intervals and devices. 3) Added any missing PRC-005-2/6 devices found during walk downs to PowerBase including the 8 missing lockout relays (located in different building from CTGs) found during Audrain EC walk down. Tested any missing PRC-005-2/6 devices added to PowerBase to ensure PRC-005-2/6 M&T interval compliance. 4) Implemented new internal controls to conduct sample audits at three year intervals at selected ECs to ensure all devices are compliant.					

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018020651	PRC-005-6	R3	Broad River Energy, LLC (BroadRiver)	NCR11313	04/01/2017	05/03/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 7, 2018, BroadRiver submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-005-6 R3. BroadRiver did not maintain its Protection System batteries in accordance with the minimum maintenance activities and maximum maintenance intervals in Table 1-4a per the NERC implementation plan. On July 1, 2018, during a self-audit, BroadRiver identified that it did not meet the implementation table for battery capacity testing as required under PRC-005-6 Table 1-4a. The NERC implementation plan requires completion of the six-year activity for 30% of batteries by April 1, 2017. Capacity testing is a six calendar year requirement under Table 1-4(a). BroadRiver has a total of five units, with one battery per unit. On May 6, 2016, BroadRiver replaced one battery and completed capacity testing on that battery at that time. As of April 1, 2017, Broad River had only met the six calendar year activity for one of its five batteries, or 20%. Broad River completed the required four calendar month and 18 calendar month activities for the five batteries, but failed to complete the required six calendar year activity for 30% of batteries by April 1, 2017. This noncompliance started on April 1, 2017, when BroadRiver did not meet the 30% implementation plan requirement for battery capacity testing, and ended on May 3, 2017, when BroadRiver completed capacity testing on 40% of its batteries. The root cause of this noncompliance was a lack of an effective transition plan to the requirements of PRC-005-6.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). BroadRiver's failure to complete the capacity test for a second battery, which would have meet the 30% requirement, by April 1, 2017 could have resulted in the associated Protection System devices not operating as designed and the next level of protection having to respond to the fault. However, BroadRiver was completing maintenance activities as required under PRC-005-1.1 during this transition and BroadRiver was only approximately one month late in meeting the 30% requirement. In addition, plant staff makes rounds daily, which include checking battery rooms and monitoring battery charger alarms. BroadRiver has battery alarms which alert plant control room personnel of any issues. BroadRiver identified no issues when completing the capacity testing; therefore, the batteries should have operated as designed. BroadRiver in an independent power producer facility that operates under purchase power agreements in the Duke Energy Balancing Area. BroadRiver is comprised of five gas-fired units with a total capacity of approximately 1,000 MW with less than a 10% capacity factor. Thus, a loss of BroadRiver would have had minimal impact to the BPS. No harm is known to have occurred. SERC considered BroadRiver's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Broad River: 1) completed battery capacity testing; and 2) developed a PRC-005-6 tracking sheet, which includes the date that the next tests are due.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018020269	PRC-005-6	R3	Cube Hydro Carolinas, LLC	NCR01169	08/1/2018	08/27/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On August 24, 2018, Cube submitted a Self-Report stating that, as a Generator Owner and Transmission Owner, it was in noncompliance with PRC-005-6 R3. Cube did not maintain its Protection System batteries in accordance with the minimum maintenance activities per PRC-005-6 R3. On August 16, 2018, during a maintenance meeting and review of current battery readings, Cube discovered that it had not performed the battery readings for the previous quarter. As a result, Cube failed to perform the required four-calendar month PRC-005-6 verification and inspection for all five batteries. This noncompliance started on August 1, 2018, when Cube failed to perform the required 4-month battery maintenance activities within the interval, and ended on August 27, 2018, when Cube performed the required 4-month battery maintenance activities. The root cause of this noncompliance was a lack of effective internal controls. The Cube quarterly battery reading schedules are in its automated maintenance system, but the supervisors overlooked the required deadlines. In addition, the subject matter expert for PRC-005-6 failed to track the deadline.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Cube's failure to conduct the 4-month battery verification and inspection within the defined interval could have impacted the functionality of the Protection System associated with all of Cube's facilities and resulted in downstream Protection System devices having to respond to faults on the system. However, Cube completed the 4-month inspection and verification less than one month late and Cube identified no issues. All of Cube's batteries and battery chargers are alarmed and monitored for loss of AC, DC voltage excursions, no charging current, and grounds. During the weekly routine maintenance rounds, Cube checks and records the battery readings. Cube has 13 units at four dams. The units total 215 MW, range in size from 157 MWs to 8.75 MWs, and operate with a combined capacity factor of about 36%. Thus, the loss of Cube generation would not result in a significant impact to the BPS. No harm is known to have occurred. The Cube has relevant compliance history. However, SERC determined that the Cube's compliance history should not serve as a basis for applying a penalty because the end dates of the prior instances of noncompliance were in February 2012.
Mitigation	To mitigate this noncompliance, Cube: 1) performed the required 4-month battery maintenance activities; 2) retrained the maintenance supervisors as to the importance of meeting the scheduled maintenance activities; and 3) added a recurring appointment on the subject matter expert and Cube's compliance officer's calendars for maintenance deadlines.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017018747	MOD-032-1	R2	City of Springfield, IL (CWLP)	NCR01328	11/01/2017	12/05/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 8, 2017, CWLP submitted a Self-Report stating that, as a Balancing Authority, Generation Owner, and Transmission Operator, it was in noncompliance with MOD-032-1 R2. CWLP did not provide CWLP did not provide steady-state, dynamics, and short circuit modeling data to its Planning Coordinator (PC), Midcontinent Independent System Operator, Inc. (MISO), within the deadline prescribed in the data requirements and reporting procedures. On December 7, 2017, a CWLP Planning Engineer notified the CWLP Superintendent of Compliance of that CWLP failed to timely respond to a MISO MOD-032-1 Model Validation data request. On June 16, 2017, MISO sent CWLP the Model Validation data request, requiring CWLP to update the Bulk Electric System (BES) model impedance discrepancies identified in the request by October 31, 2017. CWLP submitted the updated BES model data to MISO on November 30, 2017 and December 5, 2017. This noncompliance started on November 1, 2017, when CWLP did not submit the requested data to its PC by the October 31, 2017 due date, and ended on December 5, 2017, when CWLP submitted all requested data to its PC. The root cause of this noncompliance was lack of internal controls to track data requests to ensure timely data submittals.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. CWLP's failure to provide its PC accurate steady-state, dynamics, and short circuit modeling data could have resulted in the PC incorrectly modeling system behavior. Notwithstanding, the information was submitted approximately one month after the deadline, and the untimely data submittal did not cause any issues in MISO's model build or subsequent studies. No harm is known to have occurred. SERC considered CWLP's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, CWLP: 1) submitted the requested data to MISO; 2) implemented an internal control requiring specified Planning Engineer personnel to assign a task in the Outlook email to track the data request and submittals; 3) added the CWLP Superintendent of Compliance to the MISO Planning Subcommittee Committee (PSC) email distribution list, increasing the number of CWLP personnel on the distribution list from two to three; and 4) added Planning Engineer attendance to the CWLP compliance meetings for awareness of compliance issues and to help ensure adherence to NERC reliability standards.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018018999	VAR-002-4.1	R1	Duke Energy Progress, LLC (DEP)	NCR01298	10/24/2017	10/25/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On January 19, 2018, Duke Energy Progress, LLC (DEP) submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with VAR-002-4.1 R1. DEP had one instance where it failed to operate an automatic voltage regulator (AVR) in automatic controlling voltage. In November 2016, Sharon Harris Nulear Station (HNS) replaced its AVR during a refueling outage. HSN added steps to its operating procedure that it used during the commissioning of the AVR, and trained its operators on the use of the new AVR, but it did not remove those commissioning steps prior to startup and power operation. On October 22, 2017, HNS shutdown to repair a steam leak. During this shutdown, the AVR was moved to manual mode as required. On October 24, 2017, power escalation began and the generator was synchronized to the grid at 10:46 p.m. Per the Voltage Schedule assigned to HNS and HNS's operating procedures, the AVR must be in "Automatic and controlling Voltage" mode during normal operation, and startup procedures require the AVR to be in automatic mode prior to synchronizing the generator to the grid. Later that day, HNS increased power to approximately 29% power and held it there for repairs to the main condenser. At 11:48 a.m. on October 25, 2018, during a system walkdown, an engineer noticed the AVR was still in manual mode and immediately notified Operations. At 11:50 a.m the operator notified the Transmission Operator (TOP). At 12:33 p.m. the operator placed the AVR in automatic controll and notified the TOP of the change of state. The root cause of this noncompliance was a deficient procedure, which was intended to be implemented only during the commissioning of the AVR. The additional steps added to the Operator Procedure were intended to be temporarily and used only for commissioning the AVR, at which time they were supposed to have been removed. This noncompliance started on October 24, 2017, when DEP began operating the generator connected to the grid but without the AVR in automatic mode, and ended on October 25, 2017, when DEP placed the AVR in automatic controlling voltage mode.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Failure to maintain the AVR in automatic mode could result in uncontrolled voltage transients. However, Harris maintained its voltage schedule throughout the noncompliance, its TOP did not require or request any corrections or changes, and the transmission system maintained normal operation. DEP did not reach generator operating limits and there were no misoperations or voltage-related events. The operators took corrective action and notified the TOP as soon as the operator noted the discrepancy. The AVR was in manual operation mode for less than 24 hours. No harm is known to have occurred. The DEP has relevant compliance history. However, SERC determined that the DEP's compliance history should not serve as a basis for applying a penalty because of the different causes of the prior noncompliance and the current noncompliance.
Mitigation	To mitigate this noncompliance, DEP: 1) switched the AVR to automatic mode; 2) immediately submitted a Procedure Change Request to remove the added AVR commissioning language from the Operating Procedure; 3) conducted awareness training of this event and NERC requirements to all Harris licensed Operators; 4) shared the event with all applicable Nuclear Site Management and the Operations CFAM (Centralized Function Area Manager) for dissemination to their groups for awareness; and 5) verified proper operation of the new Harris AVR and related requirements of VAR-002 are included in operator training and requalification topics.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2016016593	TOP-002-2.1b	R11	Duke Energy Progress, LLC (DEP)	NCR01298	10/8/2016	10/8/2016	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 6, 2016, SERC sent DEP an audit detail letter notifying it of a compliance audit scheduled for September 6, 2016 through December 16, 2016. On November 28, 2016, DEP submitted a Self-Report stating that, as a Transmission Operator (TOP), it was in noncompliance with TOP-002-2.1b R11. DEP did not update system studies to reflect current system conditions. DEP's real-time contingency analysis tool (RTCA) performs a contingency analysis every five minutes. It also analyzes the operating system to identify islands (limited areas of interconnected load and generation no longer connected to the larger network). The analysis uses data transmitted from the field to establish which lines and generators are in service for the model. When RTCA identifies islands, the tool performs the RTCA on the smallest island and does not perform the analyses on the rest of the model. DEP TOP engineers have an option to preset the minimum number of buses to define an island in RTCA. At the time of this noncompliance, DEP had set the threshold at 5 buses. The RTCA system operates in parallel with a second, similar system that DEP uses for other system studies, Study Contingency Analysis (STCA). However, the base case used for the STCA studies is not determined in real-time and could be up to an hour old. The operator may update the status before running the model. On October 8, 2016, Hurricane Matthew moved through the DEP service territory. By 4:00 p.m. the storm had taken approximately 27 networked transmission lines out of service. At one point, the RTCA presented the System Operator with a non-alarm message that the RTCA "partially solved." The System Operators understood this message to be resulting from the loss of many transmission lines across the DEP footprint during the course of the day. A System Operator attempted to run a study on the STCA to determine the possible effect of a breaker operation and received an "island error" warning. Such warnings are a rare occurrence and are not treated as alarms. The system support staff reviewed the logs for the RTCA and discovered a similar warning occurred on that system at 3:23 p.m. RTCA had been running, but had not been solving contingencies for the entire TOP footprint since it had identified multiple islands in the model at 3:23 p.m. The cause of this noncompliance was the low setting for recognition of islands and the way DEP modeled distributed resources on transmission lines in the RTCA model. The loss of multiple transmission lines with distributed resources, inadequate alarming for multiple island detection and inadequate System Operator knowledge of RTCA impacts due to islands in the model contributed to the duration of this noncompliance. The noncompliance started 10/8/2016 at 3:23 p.m. when the RTCA stopped solving contingencies for the majority of the DEP system and ended on 10/8/2016 at 11:56 p.m. when DEP adjusted the modeling and restored RTCA.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Failure to perform seasonal, next-day, and current-day Bulk Electric System (BES) studies to determine SOLs could result in inadequate planning and improper operator responses to known and anticipated system configurations. However, in this case the accuracy of system studies was already suspect due to extensive loss of transmission and generation. If System Operators had identified potential SOL exceedances resulting from RTCA it is not likely that DEP would have pro-actively radialized the transmission line and introduced additional possible instabilities to the network. System instrumentation continued to provide indication of BES configuration, and the noncompliance did not jeopardize the Reliability Coordinator's RTCA system. In addition, the DEP System Operators were monitoring the real-time line loading and real-time transformer loading displays on their Energy Management Systems that displays the percentage of line and transformer loadings on each transmission line in service from highest % loading to lowest % loading. DEP maintained Situational Awareness of real-time line and transformer loading through System Operators monitoring these displays throughout the noncompliance. No harm is known to have occurred. SERC considered DEP's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, DEP: 1) took immediate action to manually remove the distributed generators from the RTCA model to restore RTCA operation; 2) modified the network model to convert these resources from generators to (negative) loads alleviating the issue permanently; 3) adjusted the minimum bus setting for the island definition from 5 to 12; 4) enabled an Island Detection Alarm; 5) sent all operators, operations management, and operator training an email detailing the island issue to make them aware of how to manually address/remove small islands if detected; and 6) included training for System Operators during the Fall System Operator Continuing Training.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2016016592	TOP-004-2	R1	Duke Energy Progress, LLC (DEP)	NCR01298	10/8/2016	10/8/2016	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 16, 2016, SERC sent DEP an audit detail letter notifying it of a compliance audit scheduled for September 6, 2016 through December 16, 2016. On November 28, 2016, DEP submitted a Self-Report stating that, as a Transmission Operator (TOP) it was in noncompliance with TOP-004-2 R1. DEP did not operate within its System Operating Limit (SOL). On October 8, 2016, Hurricane Matthew moved through the DEP service territory. At approximately 4:17 p.m., DEP experienced a SOL exceedance of the Weatherspoon-Fayetteville DuPont 115 kV line as a result of the loss of the Weatherspoon-Fayetteville 230 kV line during storm activity. DEP had approximately 27 networked 115 kV and 230 kV lines outaged due to the hurricane prior to the loss of the Weatherspoon-Fayetteville 230 kV line. That loss of transmission capability resulted in an overload on the Weatherspoon-Fayetteville DuPont 115 kV line. DEP has identified the Facility Rating of 119 MVA as the SOL for the Weatherspoon-Fayetteville DuPont 115 kV line. Data indicates that the line was overloaded by approximately 14% for approximately 7 seconds and then by approximately 8% for 4 minutes, 16 seconds. The system operator evaluated the overload, and mitigated the SOL exceedance by opening the Fayetteville DuPont 115 kV circuit breaker at the Fayetteville 230 kV substation by supervisory control at 4:21 p.m. The operator then notified the Reliability Coordinator (RC) of the SOL exceedance at approximately 4:30 p.m. The RC acknowledged that it had seen the overload and that DEP had corrected the SOL exceedance. The RC issued no Operating Instructions in response to the SOL exceedance. The cause of this noncompliance was hurricane-related outages that resulted in the loss of several lines. This noncompliance started on October 8, 2016 at approximately 4:16 p.m. when the DEP exceeded an SOL and ended on October 8, 2016 at approximately 4:21 p.m. when DEP corrected the SOL exceedance.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Exceeding SOLs can result in equipment damage, unanticipated line and generation losses, and voltage or frequency collapse. However, in this case the DEP operators were already operating the system in a degraded state. Despite the loss of 27 transmission lines, DEP operators had indications of the system status, awareness of the system conditions and were well trained in system operations. The operator identified the exceedance quickly and took corrective action in less than five minutes. The RC did not need to issue any Operating Instructions. The exceedance occurred on a 115kV line, and not on higher voltage, and therefore higher risk, lines. When Hurricane Matthew left the region, 58 115kV and 230 kV lines were out of service with no other exceedances identified. No load or generation was lost as a result of the exceedance. No harm is known to have occurred. SERC considered DEP's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, DEP immediately took corrective action to terminate the exceedance. Because storm activity outside of the control of DEP caused the exceedance, no additional actions are necessary to prevent a recurrence.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018020365	PRC-019-2	R1	Doswell Limited Partnership (Doswell)	NCR11193	07/01/2016	05/04/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On September 11, 2018, Doswell submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2 R1. Doswell failed to coordinate the voltage regulating system controls with the applicable equipment capabilities and settings of the applicable Protection System devices and functions in accordance with the NERC Implementation Plan. At the time of the noncompliance, the Doswell Facility consisted of two combined cycle systems and one additional peaking turbine for a total of seven generating units and 860 MWs. On June 1, 2018, Doswell added two additional generating units. In June 2016, Doswell had a coordination study performed by an outside contractor. On June 30, 2016, the contractor provided the study to Doswell. On July 20, 2016, Doswell met with the contractor to review the results of the study, which showed required relay settings changes for six generating units to meet the requirements of the Standard. Doswell was unsuccessful in finding a contractor that could change the relay settings during the fall 2016 outage. On May 4, 2017, during the spring outage, contractors changed the relay settings on units to achieve the 40% Implementation Plan requirement. On May 15, 2017, contractors completed the required relay setting changes for the six relays that required setting changes to reach 100% implementation. These six relays were associated with six generating units. In all cases, the incorrect setting was on the backup relay. As a result, if the primary relayed failed, the backup would have been slow to respond. The required changes were back-up generator protection loss of excitation from a setting of 1.6898 to 1.8574, and from a setting of 1.98, 2 cycles to 1.9471, 3 cycles. On September 18, 2017, during an internal review initiated after discovering issues with other Reliability Standards with phased implementation plans, Doswell identified that it failed to meet the 40% Implementation Plan requirement. This noncompliance started on July 1, 2016, when Doswell failed to meet the 40% Implementation Plan requirement, and ended on May 4, 2017, when Doswell completed the required relay setting changes to meet the 40% Implementation Plan requirement. The cause of the noncompliance was Doswell's misinterpretation of the percent implementation requirements. The misinterpretation related to what constituted the calculation of percentages complete. Doswell utilized percent of work completed rather than percent of Facilities completed.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Doswell's failure to verify that the voltage regulating system controls were properly coordinated with its Protection Systems could lead to a generator tripping for a system event that should not have caused the generator to trip or could fail to trip before equipment damage occurred. However, the primary relays were set correctly and the incorrect relay settings were limited to the back-up relays. On May 15, 2017, Doswell made the required relay setting changes for the six relays resulting in Doswell completing the coordination for 100% of its units two years prior to the 100% Implementation Plan requirement. In addition, the units did not trip during the period of noncompliance. The twelve month capacity factors for the two combined cycle Facilities were 53% and 60%. No harm is known to have occurred. SERC considered Doswell's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Doswell: 1) completed the required relay setting changes; 2) created a NERC Preventive Maintenance (PM) task for PRC-019 in its compliance management tool requiring a coordination study and any needed changes identified in that study is implemented within five years of the date of the last coordination study, which is currently in June 2021. This PM will be triggered approximately 6 months prior to the date the coordination study must be completed; 3) provided training for employees involved with the PRC-019-2 NERC Reliability Standard to ensure that this violation is not repeated; and 4) revised the Internal Compliance Program utilized by Doswell to ensure the implementation process for new or revised standards are understood, or that guidance is sought from NERC or the appropriate regional entity to clarify Doswell's responsibility for this action.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018020366	PRC-024-2	R1	Doswell Limited Partnership (Doswell)	NCR11193	07/01/2016	05/04/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On September 11, 2018, Doswell submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R1. Doswell failed to set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating units within the "no trip zone" of PRC-024 Attachment 1 in accordance with the NERC Implementation Pan. At the time of the noncompliance, the Doswell Facility consisted of two combined cycle systems and one additional peaking turbine for a total of seven generating units and 860 MWs. On June 1, 2018, Doswell added two additional generating units. In June 2016, Doswell had a relay coordination study performed by an outside contractor. On June 30, 2016, the contractor provided the study to Doswell. On July 20, 2016, Doswell met with the contractor to review the results of the study, which showed required relay settings changes for six generating units to meet the requirements of the Standard. Doswell was unsuccessful in finding a contractor that could change the relay settings during the fall 2016 outage. On May 4, 2017, during the spring outage, contractors changed the relay settings on units to achieve the 40% Implementation Plan requirement. On May 7, 2017, contractors completed the required relay setting changes for the six generating units to reach 100% implementation. Over-frequency and under-frequency relay setting changes were required. The required changes ranged from a setting of 60 cycles to 3441 cycles at 61.2 Hz, and from a setting of 1 second to 57.36 at 58.1 Hz seconds. On September 18, 2017, during an internal review initiated after discovering issues with other Reliability Standards with phased implementation plans, Doswell identified that it failed to meet the 40% Implementation Plan requirement. This noncompliance started on July 1, 2016, when Doswell failed to meet the 40% Implementation Plan requirement, and ended on May 4, 2017, when Doswell completed the required relay setting changes to meet the 40% Implementation Plan requirement. The root cause of the noncompliance was Doswell's misinterpretation of the percent implementation requirements. The misinterpretation related to what constituted the calculation of percentages complete. Doswell utilized percent of work completed rather than percent of Facilities completed.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Doswell's failure to set generator frequency protective relaying so that the relays do not activate and trip the applicable generating units within the "no trip zone" could lead to a generator tripping for a system event that should not have caused the generator to trip. On May 7, 2017, Doswell made the required relay setting changes resulting in Doswell completing the coordination for 100% of its units two years prior to the 100% Implementation Plan requirement. In addition, the units did not trip during the period of noncompliance. The twelve month capacity factors for the two combined cycle Facilities were 53% and 60%. No harm is known to have occurred. SERC considered Doswell's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Doswell: 1) completed the required relay setting changes; 2) created a NERC Preventive Maintenance (PM) task in its compliance management tool requiring a coordination study be performed to ensure the relay settings are maintained in accordance with PRC-024; 3) provided training for employees involved with the PRC-024-2 NERC Reliability Standard to ensure that this violation is not repeated; and 4) revised the Internal Compliance Program utilized by Doswell to ensure the implementation process for new or revised standards are understood or that guidance is sought from NERC or the appropriate regional entity to clarify Doswell's responsibility for this action.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018018995	EOP-005-2	R1	Duke Energy Carolinas, LLC (DEC)	NCR01219	09/01/2015	09/26/2016	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On January 17, 2018, DEC submitted a Self-Report stating that, as a Transmission Operator (TOP), it was in noncompliance with EOP-005-2 R1. DEC reported that it did not properly include a Cranking Path in its restoration plan. On October 19, 2017, during an extent-of-condition review related to a self-reported noncompliance of CIP-002-5 R1, DEC identified the EOP-005-2 R1 noncompliance. In its 2014 restoration plan, DEC included Lee 7C as a Blackstart Resource and described a Cranking Path from Lee to Oconee Nuclear Station. In 2014 and 2015, DEC performed reliability studies and determined that it should substitute a Jocassee-to-Oconee resource for the Lee-to-Oconee resource. DEC revised its 2015 recovery plan to show Jocassee 2 as a Blackstart Resource and Jocassee-to-Oconee as the Cranking Path. However, before receiving approval by its Reliability Coordinator, DEC realized that it had not tested Jocassee 2 as required to declare it as a Blackstart Resource, and decided to restore the original Lee-to-Oconee configuration for the 2015 restoration plan. DEC revised its recovery plan to show Lee 8C as a Blackstart Resource, but failed to change the Cranking Path back to the Lee-to-Oconee configuration. As a result, the restoration plan referred to Jocassee as the starting point for a Cranking Path, but the restoration plan did not show Jocassee as a Blackstart Resource. This noncompliance started on September 1, 2015, when DEC implemented the recovery plan with the incomplete Cranking Path, and ended on September 26, 2016, when DEC implemented the correct recovery plan. The root cause of this noncompliance was inadequate controls, e.g., a checklist, to ensure that Duke considered all sections of the recovery plan while making revisions.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Inadequate identification of Blackstart Resources and Cranking Paths will jeopardize the Transmission Operator's access to the generation resources needed for nuclear plant safety and system recovery. However, situations requiring the implementation of the recovery plan are unlikely and if Duke needed to implement the recovery plan, it correctly identified multiple Blackstart Resources and specific switching instructions would have successfully completed Cranking Paths from those resources to the critical loads such as nuclear units. When Duke tested Jocassee 2, it tested satisfactorily as a Blackstart Resource. Duke's recovery plan allows for the use of hydro units such as Jocassee 2 in the event that listed Blackstart Resources are not available. If a System Operator had chosen to use Jocassee 2, the System Operator had access to procedures that would have allowed connection to Oconee. No harm is known to have occurred. SERC considered DEC's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, DEC: 1) revised the 2016 Plan to include the Jocassee 2 Blackstart Resource along with its corresponding Cranking Path; 2) reviewed 2014 and 2017 Plans to confirm the plans listed the Cranking Paths that correctly correspond to the identified Blackstart Resources; 3) developed a checklist of items for the owner of the TOP restoration plan (Plan) that needs to be used when making a change and/or for the annual review of the TOP Plan, which will serve as an internal control when a change or annual review occurs to the TOP Plan; 4) conducted an Apparent Cause Analysis; 5) conducted a meeting with Compliance Coordination, and DEC System Operations Compliance to discuss details of the DEC TOP Plan Checklist; 6) developed a documented onboarding process from the System Operations Owner of the TOP Plan to the succeeding Owner to establish adequate transfer of knowledge; and 7) trained affected personnel on the new onboarding process.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019020952	COM-002-4	R3	Effingham County Power, LLC (ECP)	NCR11597	07/01/2016	12/11/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 14, 2019, ECP submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with COM-002-4 R3. ECP failed to retain documentation that it conducted initial training for each of its operating personnel who can receive an oral two-party, person-to-person Operating Instruction prior to that individual operator receiving an oral two-party, person-to-person Operating Instruction. On January 10, 2019, during a routine internal audit, ECP discovered that it did not have documentation for the initial training of COM-002-4 R3. On June 29, 2016, ECP sent an email to the operators with the details of the requirement as well as a copy of the plant-specific COM-002 program. The email instructed the operators to read and to reply that the operator understood the training materials. ECP retained a copy of the initial email in the corporate regulatory files. However, ECP did not retain the operator responses in the corporate regulatory files. ECP retained the email replies from the operators in an email folder. Per ECP corporate policy, ECP purges emails older than 18 months unless they are for legal or regulatory purposes. Because the responses from the operators were in an email folder and not the corporate regulatory files, ECP purged the email replies. This noncompliance started on July 1, 2016, when the Requirement became mandatory and enforceable, and ended on December 11, 2017, when the last operator completed training and ECP documented the completion. The root cause of the noncompliance was a lack of an internal control, e.g., a checklist, to ensure that evidence needed to demonstrate compliance is added to the appropriate folder.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. ECP's failure to provide initial training to its operating personnel who can receive an oral two-party, person-to-person Operating Instruction prior to that individual operator receiving an Operating Instruction could limit operators' awareness of predefined communications protocols, which could increase the possibility of miscommunication. However, the operators received an email on June 29, 2016 reminding them of this requirement along with the associated documented procedure. ECP failed to retain the emails confirming the operator's read the email and training materials by July 1, 2016. In addition, no operator received an operating instruction during an emergency. No harm is known to have occurred. SERC considered ECP's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, ECP: 1) trained all applicable compliance personnel on the documentation required for COM-002. All documentation will be retained in the appropriate NERC electronic directories and backed up; 2) will train all operators annually on the COM-002 Standard and document training; 3) will train any new employee on NERC Standard requirements as part of new employee orientation and document training; and 3) implemented a new NERC Compliance Checklist that will require someone at ECP to complete monthly. While completing this spreadsheet, the assigned person will be required to collect the required evidence to show compliance for each applicable Standard and Requirement and add it to the appropriate folder. This will help make sure evidence is not lost or misplaced. The Cogentrix Compliance department will be conducting spot checks to verify that Effingham is completing this task as assigned.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018020497	MOD-027-1	R2	East Kentucky Power Cooperative (EKPC)	NCR01225	7/1/2018	9/4/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 4, 2018, EKPC submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-027-1 R2. EKPC did not provide its Transmission Planner (TP) a verified turbine/governor and load control or active power/frequency control model in accordance with the NERC implementation plan. On June 25, 2018, EKPC submitted the MOD-027-1 model data for EKPC units to PJM Interconnection, LLC (PJM) as its TP. The EKPC data submission included EKPC's Bluegrass units 1 and 2. Also on June 25, 2018, EKPC submitted the MOD-025 data for Bluegrass units 1, 2, and 3 to PJM as the TP. PJM responded to the MOD-025-2 data submission that it was not the TP for Bluegrass unit 3. However, because PJM did not inform EKPC that it was not the TP for Bluegrass units 1 and 2 at the same time PJM informed EKPC that it was not the PC for Bluegrass unit 3, EKPC incorrectly believed that PJM was the TP for Bluegrass units 1 and 2. On September 4, 2018, PJM informed EKPC that it is not the TP for the Bluegrass units 1 and 2 and would not accept the submitted MOD-027-1 modeling data. The Bluegrass units comprised 17% of the 36% unit gross MVA for which EKPC submitted model data to PJM therefore EKPC did not meet the 30% submission requirement by July 1, 2018. The primary cause of the noncompliance was EKPC's incorrect belief that since EKPC is a member of PJM, that PJM is the TP for all EKPC units, including EKPC's Bluegrass units. This noncompliance started on July 1, 2018 when EKPC was required to meet the 30% implementation plan and ended on September 4, 2018, when EKPC submitted the model data to its TP and met the 30% implementation plan requirement.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. EKPC's failure to provide its TP verified model data for Bluegrass units 1 and 2 could results in inaccurate system models. However, EKPC provided the data for Bluegrass units 1 and 2 only 65 days late for a requirement that has a full implementation requirement of July 1, 2024. No harm is known to have occurred. SERC considered EKPC's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, EKPC: 1) provided the model data for Bluegrass to LGE and KU; and 2) developed an internal document noting the TP for all individual EKPC generation units and distributed this document to all relevant Standards owners.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018020496	MOD-026-1	R2	East Kentucky Power Cooperative (EKPC)	NCR01225	7/1/2018	9/4/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 4, 2018, EKPC submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-026-1 R2. EKPC did not provide its Transmission Planner (TP) a verified generator excitation control system or plant volt/var control function model in accordance with the NERC implementation plan. On June 25, 2018, EKPC submitted the MOD-026-1 model data for EKPC units to PJM Interconnection, LLC (PJM) as its TP. The EKPC data submission included EKPC's Bluegrass units 1 and 2. Also on June 25, 2018, EKPC submitted the MOD-025 data for Bluegrass units 1, 2, and 3 to PJM as the TP. PJM responded to the MOD-025-2 data submission that it was not the TP for Bluegrass unit 3. However, because PJM did not inform EKPC that it was not the TP for Bluegrass units 1 and 2 at the same time PJM informed EKPC that it was not the PC for Bluegrass unit 3, EKPC incorrectly believed that PJM was the TP for Bluegrass units 1 and 2. On September 4, 2018, PJM informed EKPC that it is not the TP for the Bluegrass units 1 and 2 and would not accept the submitted MOD-026-1 modeling data. The Bluegrass units comprised 17% of the 36% unit gross MVA for which EKPC submitted model data to PJM therefore EKPC did not meet the 30% submission requirement by July 1, 2018. The primary cause of the noncompliance was EKPC's incorrect belief that since EKPC is a member of PJM, that PJM is the TP for all EKPC units, including EKPC's Bluegrass units. This noncompliance started on July 1, 2018 when EKPC was required to meet the 30% implementation plan and ended on September 4, 2018, when EKPC submitted the model data to LGE and KU and met the 30% implementation plan requirement.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. EKPC's failure to provide its TP verified model data for Bluegrass units 1 and 2 could results in inaccurate system models. However, EKPC provided the data for Bluegrass units 1 and 2 only 65 days late for a requirement that has a full implementation requirement of July 1, 2024. No harm is known to have occurred. SERC considered EKPC's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, EKPC: 1) provided the model data for Bluegrass to LGE and KU; and 2) developed an internal document noting the TP for all individual EKPC generation units and distributed this document to all relevant Standards owners.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017017287	PRC-004-4(i)	R1	Entergy (Entergy)	NCR01234	11/13/2016	12/13/2016	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On March 28, 2017, Entergy submitted a Self-Report stating that, as a Transmission Owner it was in noncompliance with PRC-004-4(i) R1. Entergy did not determine the cause of a misoperation within 120 days of the operation. On July 15, 2016, a fault occurred on a 115 kV transmission line, tripping breakers on both ends of the line and also tripping an interconnected line at the far end. Following an initial analysis on the same day, Entergy concluded that an incorrect operation had occurred, however there is no record of Entergy issuing a Condition Report (CR) per its procedure to begin a detailed assessment of the Misoperation cause. If Entergy had followed its procedure, then it would have issued a CR to investigate the potential Misoperation and begin a corrective action plan if applicable. On November 17, 2016, in preparation for quarterly reporting of Misoperations to the ERO, Entergy generated a quarterly report used to identify outages that its System Operators recorded with a relay response type of "Incorrect". Entergy also uses that report to verify that it has generated a CR for possible Misoperations. Based on a preliminary third quarter version of this report, Entergy discovered there was no CR for the July 15, 2016 possible Misoperation and Entergy promptly initiated a CR. On December 13, 2016, 151 days after the operation, Entergy completed its assessment, determined a Misoperation had occurred and identified its probable cause. The cause of the noncompliance is that Entergy failed to follow its procedure and thereby failed to submit the CR that would have triggered the Misoperation cause identification. The noncompliance started on November 13, 2016, 121 days after the misoperation and ended on December 13, 2016 when Entergy identified the cause of the misoperation.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Failure to properly identify the cause of a relay Misoperation within 120 days delays the correction of the cause and presents the opportunity for additional misoperations. However, in this case, the misoperation was not caused by incorrect Protection System functions, but the fault conditions caused the actuation of only one additional distance relay and the tripping of one additional breaker. Post-trip analysis determined that all relays functioned as designed and adjusted and that the additional relay actuation occurred due to the nature of the fault. Entergy did identify the cause of the Misoperation and was only approximately one month late in doing so. The same type of misoperation has not reoccurred and no other misoperation occurred on this line. No harm is known to have occurred. SERC considered Entergy's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Entergy: 1) identified the correct Protection System component as cause of the Misoperation; 2) performed a Causal Determination in order to determine the cause of the event and actions were taken to prevent recurrence; 3) determined, based on interviews, applicable human performance traps included perceived time pressure to complete relay reviews quickly and avoid the Relay Review "still pending" list; overconfidence in assessing what appeared to be a typical overtrip event; and Off-normal / Infrequent Conditions associated with this being a NERC defined Slow Trip Misoperation. Applicable Human Performance tools not used effectively included Self Checking, Procedure Usage, Questioning Attitude, and Place Keeping; 4) provided refresher training to Grids, with emphasis on the following items: a. The need to create a CR immediately, if not already created, upon COS completed relay review determination of a suspected or confirmed Misoperation; b. NERC's Misoperation definition, in particular "Slow Trip", to ensure future accurate identification of Misoperations; c. Remote Zone 3 trips warrant additional scrutiny and are not always indicative of an overtrip; d. The need to designate relay reviews as completed only after all necessary review activities have been performed, inclusive of supporting documentation. 5) Completed refresher training.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018018944	MOD-027-1	R5	Entergy (Entergy)	NCR01234	9/17/2017	10/24/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 4, 2018, Entergy submitted a Self-Report stating that, as a Transmission Planner (TP), it was in noncompliance with MOD-027-1 R5. Entergy reported it did not provide a written response to the Generator Owner (GO) within 90 days of a model verification that the model was usable or not usable. Prior to January 16, 2017, Entergy Power Generation plant personnel (GO) performed communications with Transmission Planning employees concerning MOD-026-1 and MOD-027-1 by using emails directed to the employees. On January 16, 2017, a new Power Generation procedure became effective which directed Entergy Power Generation plant personnel to send model information to a specific email mailbox. Transmission Planning had been involved in the procedure development, but Transmission Planning employees were unaware of the effective date of this procedure or the existence of the new, dedicated mailbox. As a result, Transmission Planning employees had not been monitoring the mailbox. Between January and the beginning in June 2017, Entergy Power Generation plant personnel continued to direct email to individual Transmission Planner employees as well as the new mailbox, but in June 2017, Power Generation employees sent some of the communications exclusively to the dedicated mailbox. Transmission Planning became aware of this in October during a meeting between Power Generation and Transmission Planning to discuss modeling data, and then retrieved the overlooked requests. While most requests were still within the 90 days response requirement, one request dated June 19, 2017 was beyond the 90 day requirement to respond. The cause of the noncompliance is the lack of comprehensive change management communication from Power Generation to Transmission Planning before the effective date of the new Power Generation procedure. This resulted in Transmission Planning failing to regularly check the dedicated mailbox but relied solely on emails directly sent to Transmission Planning personnel. This noncompliance started on September 17, 2017, 90 days after the submission of model verification, and ended 37 days later on October 24, 2017, when Entergy responded to the GO.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Failure to acknowledge receipt of a verified model could delay accurate modeling. However, in this case the model was satisfactory and no model changes were necessary. If changes had been necessary, the delay involved one 208 MVA unit and would not have greatly affected model results. Furthermore, the implementation plan for MOD-027-1 allows ten years to reach full compliance. SERC considered Entergy's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Entergy: 1) responded to the GO; 2) set up an Outlook rule to email the Transmission Planning employees every time the dedicated email box received an email; and 3) updated procedure guidance to ensure proper change management occurs and provide training to appropriate individuals.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017017816	PRC-005-2(i)	R3	Georgia Transmission Corporation (GTC)	NCR01249	7/9/2015	5/25/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On April 25, 2017, SERC sent GTC an audit detail letter notifying it of a compliance audit scheduled for April 25, 2017 through August 11, 2017. On June 22, 2017, GTC submitted a Self-Report stating that, as a Transmission Owner, it was in noncompliance with PRC-005-6 R3. GTC did not perform the battery testing in accordance with Table 1-4(a) of PRC-005-6 for one battery. SERC later determined that the start date of the noncompliance began under version PRC-005-2(i) of the Standard. On May 24, 2017, during an internal controls review of battery testing data for all of GTC's substations, GTC identified that it did not meet the minimum maintenance requirements of PRC-005-6 for a single battery at the Cuthbert Primary substation. GTC determined that it had not performed the required 18-month maintenance and testing as of July 9, 2015, the date the station became classified as a Bulk Electric System (BES) station. Prior to July 2015, the Cuthbert Primary substation was in-service and classified as an underfrequency only station, and therefore did not require battery testing as per Table 1-4 (a) of PRC-005-2(i). On July 9, 2015, GTC installed a 115 kV capacitor bank, a BES element, which resulted in the battery being a Protection System device required to meet the requirements of PRC-005-2(i) Table 1-4(a). After installation of the capacitor bank, GTC personnel failed to set the flag for battery testing in GTC's maintenance management system to indicate the battery required maintenance and testing as per PRC-005-2(i). As a result, GTC's maintenance management system did not identify the battery as a BES device requiring battery testing. GTC completed all required maintenance activities in Table 1-4(a) prior to the bank being used as a BES Protection System component, including an impedance test. However, GTC performed the last impedance test on December 18, 2013; therefore, the 18-month requirement was out of interval as of July 9, 2015. Although GTC did not correctly designate the battery as a BES device, GTC performed all other Table 1-4(a) activities within the required interval. GTC completed a walk-down of all PRC-005-6 applicable transmission facilities, verified that all other PRC-005-6 elements were correctly identified, verified that all included PRC-005-6 devices were entered into the maintenance management system with the correct tasks and intervals, and verified complete documentation of required maintenance and testing requirements. GTC did not identify any additional issues. The primary cause of the noncompliance was ineffective training, which resulted in a lack of awareness of additional requirements for BES equipment and the importance of correct identification in the maintenance management system. This noncompliance started on July 9, 2015, when Cuthbert Primary substation became a BES station and GTC had not performed the 18-month Table 1-4(a) maintenance and testing, and ended on May 25, 2017, when GTC completed the required maintenance and testing.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. GTC's failure to conduct the 18-month battery maintenance and testing requirements within the defined interval could have impacted the functionality of the Protection System associated with the Cuthbert Primary substation and resulted in downstream Protection System devices having to respond to faults on the transmission system. However, GTC monitors its battery systems voltages through its Supervisory Control and Data Acquisition system, which should detect battery issues. GTC monitors battery voltages and alarms annunciate when voltages go outside of acceptable ranges. GTC performs a visual inspection, which includes checking electrolyte levels in each cell, corrosion, and overall physical conditions of the batteries on the batteries every month. The battery system showed no degradation and battery testing revealed no problems with the battery system. The battery system is performing as designed. No harm is known to have occurred. SERC considered GTC's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, GTC: 1) completed the 18-month battery testing at the Cuthbert Primary substation; 2) raised awareness of the compliance concern by having Relay Maintenance share details of the findings and mitigating activities with GTC's Reliability Assurance Sub-Committee (RAC) and ERO Compliance Steering Committee; 3) delivered training developed by Relay Maintenance to applicable GTC employees on integration of new components and/or stations into GTC's Protection System Maintenance Program (PSMP); 4) designed and implemented an automated report in Maximo to identify any time a BES breaker (100 kV or above) is added to a non-BES station to flag the new addition; and 5) implemented a new bi-annual process developed by Relay Maintenance to review all stations within Maximo; the process identifies and flags any new or modified stations that should be integrated into GTC's PSMP, and creates a battery work order when necessary.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2019020951	MOD-032-1	R2	LG&E and KU Services Company as agent for Louisville Gas and Electric Company and Kentucky Utilities Company (LGE and KU)	NCR01223	04/13/2016	12/27/2017	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On January 14, 2019, LGE and KU submitted a Self-Log stating that, as a Generator Owner (GO), it was in noncompliance with MOD-032-1 R2. LGE and KU failed to provide accurate steady-state, dynamics, and short circuit modeling data to its Planning Coordinator (PC) according to the data requirements and reporting procedures developed by its PC and Transmission Planner in Requirement R1. In December 2017, the PC submitted a request for MOD-032 data to LGE and KU. On December 8, 2017, while reviewing the MOD-032 data provided by the PC, an LGE and KU GO employee identified errors with the MOD-032 data LGE and KU previously submitted on April 13, 2016. Specifically, the data previously reported to the PC indicated that the governor was functional for nine units; however, LGE and KU had not enabled governor functionality on the units. LGE and KU also identified errors in the MOD-032 data submitted for the Power System Stabilizer (PSS) for a unit. The data from the PC indicated an active PSS, but LGE and KU tested the unit's PSS when the unit was commissioned then turned the PSS off. In December 2017, to ensure that LGE and KU identified all MOD-032 data errors, LGE and KU GO performed a review of the previously reported MOD-032 data. This included a review of the information related to governor and PSS status, capabilities and parameters for all LGE and KU facilities, and a review of drawings and manuals, and consultations with equipment manufacturers to ensure the accuracy of the information. This noncompliance started on April 13, 2016, when LGE and KU submitted inaccurate unit data for 10 units to its PC, and ended on December 27, 2017, when LGE and KU submitted accurate unit data for 10 units to its PC. The root cause of this noncompliance was lack of a documented process for MOD-032-1 R2 data submissions.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). LGE and KU's failure to provide accurate data could have resulted in the PC planning models and studies producing inaccurate results that would prevent the PC from adequately conducting analyses of the system to support the reliability of the BPS. However, this issue impacted 10 units and could have resulted in generating unit protection systems isolating any trips to the individual affected unit. The LGE and KU PC conducted a Governor Removal Comparison Study, which found there were no stability issues to the BPS as well as no impacts to TPL standards as a result of LGE and KU not enabling the governor functionality. No harm is known to have occurred. SERC considered LGE and KU's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, LGE and KU: 1) submitted accurate MOD-032 data to the PC; 2) implemented a job aid, which provides a process as to how the LGE and KU GO reviews and provides MOD-032 data to the PC; and 3) implemented compliance guidance and training addressing when to notify LGE and KU Generation Compliance in regards to projects/plans to modify generator, excitation system, governor, power system stabilizer.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018019639	PRC-006-SERC-01	R2	PJM Interconnection, LLC (PJM)	NCR00879	4/4/2014	3/23/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On May 4, 2018, PJM submitted a Self-Report stating that, as a Planning Authority (PA), it was in noncompliance with PRC-006-SERC-1 R2. PJM did not identify an Underfrequency Load Shed (UFLS) scheme with time delay Requirements for UFLS entities that are Distribution Providers (DP) registered in SERC. PJM maintains a UFLS program for its Planning Coordinator area that allows for the automatic shedding of load during abnormal frequency, voltage, or power flow conditions. PJM Manual 13: Emergency Operations contains general details of the program. That program is applicable to five registered entities in the SERC region who are members of PJM and is the vehicle for PJM to inform its member TOs and DPs of UFLS requirements. On January 3, 2018, a DP registered in the SERC region that is a member of PJM contacted PJM to request PJM's requirements for UFLS scheme time delay in relation to PRC-006-SERC Requirement R2.6. After reviewing PJM's processes and procedures, PJM determined that it did not select or establish time delay requirements in accordance with the PRC-006-SERC-2. In the past, PJM has utilized a report prepared for SERC by a third party to help specify appropriate UFLS schemes however, while the report details time load shed and time delay requirements for Transmission Owner (TO) zones within the SERC region, the report did not specifically establish time delay requirements for DPs. After learning of this issue, and upon investigation, PJM confirmed it did not specify a time delay requirement for any of its TOs or DPs in the SERC region. SERC determined that the cause of this noncompliance was that PRC-006-SERC-2 retains and specifies design requirements which PJM overlooked when informing SERC entities of their UFLS responsibilities. This noncompliance started on April 4, 2014 when PRC-006-SERC-1 became enforceable, and ended on March 23, 2018 when PJM issued the time delay requirement.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. By not specifying a UFLS time delay, a low frequency disturbance it could have resulted in an unnecessary load shed. However, during an actual under-frequency event it would result in an anticipatory load shed and could enhance system response to the event. If the load shed were inadvertent, the DP could restore it quickly. In this case, PJM learned that the only load in SERC that did not use the required six-cycle time delay was a single DP that accounted for 301 MW of 7,259 MW of load (4.1%) in the SERC region. All other SERC-based load used the SERC-required time delay. No load was lost as a result of the incorrect time delay. No harm is known to have occurred. SERC considered PJM's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, PJM: 1) Reviewed current version of PJM Manual 36 Attachment H to identify the PJM UFLS entities within the SERC region; 2) Worked with the PJM UFLS entities within the SERC region to ensure the UFLS scheme time delay requirement is set to at least six cycles. a. Issued time delay requirement notification to PJM UFLS entities within SERC via email; b. Started the Stakeholder Process for PJM Manual 36 Attachment H revisions to add PJM's time delay Requirement; and c. Completed the Stakeholder Process for PJM Manual 36 Attachment H revisions to add PJM's time delay Requirement.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018018921	MOD-026-1	R6	South Carolina Electric & Gas Company (SCEG)	NCR00915	12/12/2016	10/06/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On January 2, 2018, SCEG submitted a Self-Report stating that, as a Transmission Planner, it was in noncompliance with MOD-026-1 R6. SCEG did not provide a written response to the Generator Owner (GO) within 90 calendar days of receiving the verified excitation control system or plant volt/var control function model information in accordance with Requirement R2 that the model is usable or is not usable. On two occasions, SCEG did not provide notification to the GO that the model data received from an independent GO within its Transmission Planning area was usable or not useable. On September 12, 2016, an independent GO sent SCEG model data, via email, to satisfy the MOD-026-1 R2 requirement. SCEG did not provide any notification to the GO after that submission. On May 8, 2017, the same GO referenced the previously submitted MOD-026-1 model data in another email; however, on this occasion, it did so in a SCEG email with the subject line "NERC Reliability Standard MOD-032 Reporting Data." Because of the subject line, SCEG did not immediately identify that the data was MOD-026-1 data and again did not provide any notification to the GO. On July 25, 2017, the GO sent a revised version of the model data to SCEG. On September 5, 2017, the GO contacted SCEG requesting documentation of notification that the MOD-026-1 models were useable. On October 6, 2017, SCEG discovered that it did not confirm the model data was usable or not usable for the September 12, 2016 and May 8, 2017 submissions. On October 6, 2017, SCEG sent an email to the GO confirming that the latest version of the model data submitted on July 25, 2017 was usable. This noncompliance started on December 12, 2016, when SCEG failed to provide the required written notification to the GO within 90 days from receipt of model data from the GO, and ended on October 6, 2017, when SCEG provided notification to the GO that the data was usable. The root cause of this noncompliance was lack of training. The GO made its initial September 2016 submittal to the SCEG Electric Transmission Support Department, which is not the department that responds to such submittals, and thus, was not aware that SCEG needed to respond to the GO's data submittal. Additionally, the GO made its May 2016 submittal responding to an email with a MOD-032 subject line; therefore, SCEG did not immediately recognize the submittal as a MOD-026-1 data submittal. A more careful reading by SCEG of the GO's document would have prevented this oversight.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. SCEG's failure to respond to the model data submission within the required 90 days could have led to incorrect models resulting in erroneous assessments or an incorrect corrective action plan for the independent GO's combined cycle facility. However, SCEG validated the models via simulation software to demonstrate proper applications of these models. SCEG modeled the generator, exciter, power system stabilizer, and governors for the combined cycle facility using previously provided modeling data and identified no potential stability issues in the system. SCEG also modeled the generator, exciter, power system stabilizer, and governors for the combined cycle facility using the updated modeling data and identified no potential stability issues in the system. No harm is known to have occurred. SERC considered SCEG's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, SCEG: 1) sent a confirmation e-mail back to the GO confirming that the model data was usable; and 2) provided training to the appropriate SCEG Transmission Planning personnel.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018018922	MOD-027-1	R5	South Carolina Electric & Gas Company (SCEG)	NCR00915	12/12/2016	10/06/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On January 2, 2018, SCEG submitted a Self-Report stating that, as a Transmission Planner, it was in noncompliance with MOD-027-1 R5. SCEG did not provide a written response to the Generator Owner (GO) within 90 calendar days of receiving the turbine/governor and load control or active power/frequency control system verified model information in accordance with Requirement R2 that the model is usable or is not usable. On two occasions, SCEG did not provide notification to the GO that the model data received from an independent GO within its Transmission Planning area was usable or not useable. On September 12, 2016, an independent GO sent SCEG model data, via email, to satisfy the MOD-026-1 R2 requirement. SCEG did not provide any notification to the GO after that submission. On May 8, 2017, the same GO referenced the previously submitted MOD-026-1 model data in another email; however, on this occasion, it did so in a SCEG email with the subject line "NERC Reliability Standard MOD-032 Reporting Data." Because of the subject line, SCEG did not immediately identify that the data was MOD-026-1 data and again did not provide any notification to the GO. On July 25, 2017, the GO sent a revised version of the model data to SCEG. On September 5, 2017, the GO contacted SCEG requesting documentation of notification that the MOD-027-1 models were useable. On October 6, 2017, SCEG discovered that it did not confirm the model data was usable or not usable for the September 12, 2016 and May 8, 2017 submissions. On October 6, 2017, SCEG sent an email to the GO confirming that the latest version of the model data submitted on July 25, 2017 was usable. This noncompliance started on December 12, 2016, when SCEG failed to provide the required written notification to the GO within 90 days from receipt of model data from the GO, and ended on October 6, 2017, when SCEG provided notification to the GO that the data was usable. The root cause of this noncompliance was lack of training. The GO made its initial September 2016 submittal to the SCEG Electric Transmission Support Department, which is not the department that responds to such submittals, and thus, was not aware that SCEG needed to respond to the GO's data submittal. Additionally, the GO made its May 2016 submittal responding to an email with a MOD-032 subject line; therefore, SCEG did not immediately recognize the submittal as a MOD-027-1 data submittal. A more careful reading by SCEG of the GO's document would have prevented this oversight.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. SCEG's failure to respond to the model data submission within the required 90 days could have led to incorrect models resulting in erroneous assessments or an incorrect corrective action plan for the independent GO's combined cycle facility. However, SCEG validated the models via simulation software to demonstrate proper applications of these models. SCEG modeled the generator, exciter, power system stabilizer, and governors for the combined cycle facility using previously provided modeling data and identified no potential stability issues in the system. SCEG also modeled the generator, exciter, power system stabilizer, and governors for the combined cycle facility using the updated modeling data and identified no potential stability issues in the system. No harm is known to have occurred. SERC considered SCEG's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, SCEG: 1) sent a confirmation e-mail back to the GO confirming that the model data was usable; and 2) provided training to the appropriate SCEG Transmission Planning personnel.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018019759	COM-002-4	R3	Tilton Energy, LLC (Tilton)	NCR11014	07/01/2016	05/18/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On May 21, 2018, Tilton submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with COM-002-4 R3. Tilton does not have documentation that it conducted initial training for each of its operating personnel who can receive an oral two-party, person-to-person Operating Instruction prior to that individual operator receiving an oral two-party, person-to-person Operating Instruction. On January 15, 2018, a third party, Cogentrix Energy Power Management, LLC (CEPM), assumed operations and managed support for Tilton. On March 21, 2018, during an internal audit of Tilton, CEPM determined that although Tilton stated that it had conducted COM-002-4 R3 operator training prior to the July 1, 2016 effective date, Tilton was unable to provide training documentation. This noncompliance started on July 1, 2016, when the Standard became enforceable, and ended on May 18, 2018, when Tilton completed the training of its operators. The root cause of the noncompliance was ineffective training record document management.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Tilton's failure to provide formal COM-002-4 R3 training to its operating personnel prior to them receiving an Operating Instruction could limit operators' awareness of predefined communications protocols, which could increase the possibility of miscommunication. However, according to Tilton, it trained its generator operators on communication protocols prior to July 1, 2016 but failed to retain training documentation. COM-002-4 R3 is a new Requirement and Tilton operators had been operating the system without issue prior to July 1, 2016. Additionally, Tilton is a small facility that consists of four simple cycle gas turbines rated at 45MW each. Tilton is a peaking facility with capacity factors ranging from 1.48% to 7.27% for each of the past six years. No harm is known to have occurred. SERC considered Tilton's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Tilton: 1) trained operating personnel on COM-002-4 requirements; 2) added COM-002 training to the new hire checklist; and 3) updated the training record retention process and policy to address the documentation for NERC training and how long the records need to be retained.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018019799	TPL-001-4	R8	Tennessee Valley Authority (TVA)	NCR01151	9/22/2016	3/8/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On May 15, 2018, SERC sent TVA an audit notification letter notifying it of a compliance audit scheduled for September 10, 2018 through September 14, 2018. On June 4, 2018, TVA submitted a Self-Report stating that, as a Planning Coordinator (PC) and Transmission Planner (TP), it was in noncompliance with TPL-001-4 R8. TVA did not distribute its Planning Assessment results to adjacent PCs and adjacent TPs within 90 calendar days of completing its Planning Assessment. On July 12, 2017, TVA completed and signed its 2017 Planning Assessment. On March 6, 2018, 239 days after TVA completed its 2017 Planning Assessment, and while preparing for its 2018 Planning Assessment, TVA determined that it did not distribute its 2017 Planning Assessment results to adjacent PCs and adjacent TPs within 90 days of completing the assessment as required. After identifying the 2017 noncompliance, TVA reviewed the 2016 Planning Assessment distribution. On June 23, 2016, TVA completed and signed its 2016 Planning Assessment. On October 26, 2016, 126 days after the completion of the 2016 Planning Assessment, TVA distributed the 2016 Planning Assessment results to the adjacent PCs and adjacent TPs. The cause of the noncompliance was TVA's lack of an effective internal control. TVA's distribution of its annual Planning Assessment results was dependent on one person remembering to send the TVA Planning Assessment results to all adjacent PCs and TPs. The first instance of noncompliance started on September 22, 2016, 91 days after completion of the 2016 Planning assessment, and ended on October 26, 2016, when TVA distributed its 2016 Planning Assessment results to adjacent PCs and adjacent TPs. The second instance of noncompliance started on October 11, 2017, 91 days after completion of the 2017 Planning assessment, and ended on March 8, 2018, when TVA distributed its 2017 Planning Assessment results to adjacent PCs and adjacent TPs.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. TVA's failure to distribute its Planning Assessment within 90 days of completion could result in adjacent PCs and TPs lacking awareness of changes planned for the TVA transmission system, and therefore the entities could not properly assess the potential implications of those changes on the adjacent systems. However, as a registered PC and TP, TVA shares information regarding its system, including planned changes, through joint modeling and study activities it participates in with adjacent PCs and TPs. These joint model development and study reports methods of information sharing with neighboring PCs and TPs pre-date the January 1, 2016 enforceable date of TPL-001-4 R8, and continue to serve as an effective means of informing adjacent entities of future plans. No harm is known to have occurred. SERC considered TVA's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, TVA: 1) distributed the 2017 Planning Assessment to adjacent PCs and TPs; 2) developed a new TPL-001-4 checklist as part of the final approval / signature stage for the annual Planning Assessment. The checklist includes a verification that the Planning Assessment results have been distributed to adjacent PCs and TPs; and 3) revised the coversheet for the TVA annual Planning Assessment documents to incorporate a new checkbox to affirm that personnel completed the TPL-001-4 checklist prior to affixing approval signatures to the Planning Assessment documents; and 4) conducted an evaluation to assess other NERC standards that have similar event-driven notification requirements.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018019361	PRC-024-2	R2	Virginia Electric and Power Company – Nuclear (GO, GOP) (VEP-Nuc)	NCR09006	7/1/2016	3/7/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On March 7, 2018, VEP-Nuc submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R2. VEP-Nuc did not verify that it set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating units as a result of a voltage excursion within the "no trip zone" of PRC-024 Attachment 2 in accordance with the PRC-024-2 implementation plan. VEP-Nuc has four applicable Facilities. During an affiliate's review of its PRC-024 documentation, the affiliate determined that its voltage protective relays did not account for the generator step-up (GSU) transformer turns ratio in the voltage translation calculations. On February 13, 2018, as part of the affiliate's extent of condition evaluation, the affiliate notified VEP-Nuc of this omission. On February 13, 2018, VEP-Nuc reviewed its PRC-024-2 evaluation and determined that it did not consider the GSU turns ratio. VEP-Nuc also determined that it did not consider transformer loading. The evaluations that included the GSU and transformer loadings found that VEP-Nuc's relay and automatic voltage regulator (AVR) settings are outside of the no trip zone and thus required no changes. The cause of the noncompliance was lack of oversight. VEP-Nuc inadvertently overlooked guidance within NERC Reliability Standard PRC-024 regarding the voltage protective relays. This noncompliance started on July 1, 2016, the first date of required compliance with PRC-024-2 R2, and ended on March 7, 2018, when VEP-Nuc completed evaluations with GSU turns ratio and transformer loading.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). VEP-Nuc's failure to ensure relaying does not trip within the "no trip zone" could result in generating units unexpectedly disconnecting from the BPS during disturbances. However, the revised evaluations determined that all applicable settings were outside the no-trip zone and thus no setting changes were required. The VEP-Nuc generating units range from 858 MWs to 980 MWs with 2017 annual capacity factors of approximately 90%. VEP-Nuc is not aware of a generating unit disconnecting from the BPS during a voltage excursion as a result of an incorrect relay setting during the evaluation period. No harm is known to have occurred. SERC considered VEP-Nuc's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, VEP-Nuc: 1) re-evaluated the voltage protective relays including GSU turns ratio and transformer loading; 2) provided training to applicable staff regarding PRC-024-2 evaluations and lessons learned; and 3) provided training to applicable staff on lessons learned and guidance on reviewing Reliability Standards to ensure compliance.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017018830	PRC-004-2.1a	R3	Virginia Electric and Power Company – Power Generation (VEP-PG)	NCR09028	6/1/2015	7/1/2016	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 18, 2017, VEP-PG submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-004-2.1a R3. VEP-PG, in its 2015 first quarter report, did not provide SERC complete documentation of its Protection System operations in accordance with SERC's Misoperations analyses and Corrective Action Plans procedure. On November 16, 2017, while performing an internal audit, VEP-PG discovered a discrepancy in its 2015 first quarter reporting (Q1). On April 29, 2015, VEP-PG entered its 2015 Q1 data submittal in the SERC Reliability Portal. VEP-PG documented one Protection System Misoperation and one Protection System operation at that time. During the internal audit, VEP-PG identified an additional 230 kV voltage class Protection System operation that occurred in Q1 that it did not report. The SERC procedure required the entity to report the first quarter count of total Protection System operations per voltage level by May 31. On January 24, 2015, the Chesterfield 6 operation occurred. On January 24, 2015, station personnel and the relay department completed an assessment of this operation and determined it was a correct operation. On January 27, 2015, VEP-PG entered the operation into its Power Generation System Operations Event Report database. VEP-PG determined that the primary causes of the noncompliance were human performance due to improper assumptions, indicating the need for retraining, and a gap in its internal processes, indicating the need to revise processes and strengthen internal controls. This noncompliance started on June 1, 2015, the first date after the submission deadline, and ended on July 1, 2016, when PRC-004-4(i) became enforceable and did not require reporting.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). VEP-PG's failure to report all Protection System operations could have limited SERC's situational awareness of the operations in the SERC footprint and its ability to monitor, analyze and track trends which could hinder the ability to improve BPS reliability. However, this noncompliance was solely a failure to report a correct operation of the Protection System to SERC. In addition, the current version of the Standard no longer requires reporting to SERC or NERC as a compliance obligation. No harm is known to have occurred. SERC considered VEP-PG's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, VEP-PG: 1) performed an internal review of program documents including, but not limited to, NERC Compliance Procedures, guidance documents, job aids, and process maps; 2) counseled the Power Generation Regulatory Compliance (PGRC) lead; 3) updated program documents to address weaknesses identified during the extent of condition assessment; 4) created an Internal Controls document for use by PGRC to ensure the identification, assessment, submittal and documentation of operations in a consistent manner. This document also outlines a monthly reconciliation process of operations to ensure retention of event review reports from the Power Generation System Operations Event Report database, assessments, root cause analyses, Corrective Action Plans and other supporting documentation; 5) provided training to site personnel and Power Generation Engineering; and 6) notified SERC of 2015 Q1 and Q2 Operations/Misoperations discrepancy.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017018831	PRC-004-2.1(i)a	R3	Virginia Electric and Power Company – Power Generation (VEP-PG)	NCR09028	9/1/2015	7/1/2016	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 18, 2017, VEP-PG submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-004-2.1a R3. VEP-PG, in its 2015 second quarter report, did not provide SERC complete documentation of its Protection System operations in accordance with SERC's Misoperations analyses and Corrective Action Plans procedure. On November 16, 2017, while performing an internal audit, VEP-PG discovered a discrepancy in its 2015 second quarter reporting (Q2). On August 27, 2015, VEP-PG entered its 2015 Q2 data submittal in the SERC Reliability Portal. VEP-PG documented one Protection System Misoperation and one Protection System operation at that time. During the internal audit, VEP-PG identified an additional 500 kV voltage class Protection System operation that occurred in Q2 that it did not report. The SERC procedure requires the entity to report the count of total Protection System operations per voltage level for second quarter by August 31 each year. On June 19, 2015, the Warren County operation occurred. On June 23, 2015, station personnel and the relay department completed an assessment of this operation and determined it was a correct operation. On June 23, 2015, VEP-PG created a Unit Disturbance Report. VEP-PG determined that the primary causes of the noncompliance were human performance due to improper assumptions, indicating the need for retraining, and a gap in its internal processes, indicating the need to revise processes and strengthen internal controls. This noncompliance started on September 1, 2015, the first date after the submission deadline, and ended on July 1, 2016, when PRC-004-4(i) became enforceable and did not require reporting.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). VEP-PG's failure to report all Protection System operations could have limited SERC's situational awareness of the operations in the SERC footprint and its ability to monitor, analyze, and track trends, which could hinder the ability to improve BPS reliability. However, this noncompliance was solely a failure to report correct operations of the Protection System to SERC. In addition, the current version of the Standard no longer requires reporting to SERC or NERC as a compliance obligation. No harm is known to have occurred. SERC considered VEP-PG's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, VEP-PG: 1) performed an internal review of program documents including, but not limited to, NERC Compliance Procedures, guidance documents, job aids, and process maps.; 2) counseled the Power Generation Regulatory Compliance (PGRC) lead; 3) updated program documents to address weaknesses identified during the extent of condition assessment;4) created an Internal Controls document for use by PGRC to ensure the identification, assessment, submittal and documentation of operations in a consistent manner. This document also outlines a monthly reconciliation process of operations to ensure retention of event review reports from the Power Generation System Operations Event Report database, assessments, root cause analyses, Corrective Action Plans and other supporting documentation; 5) provided training to site personnel and Power Generation Engineering; and 6) notified SERC of 2015 Q1 and Q2 Operations/Misoperations discrepancy.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018019331	PRC-024-2	R2	Virginia Electric and Power Company – Power Generation (VEP-PG)	NCR09028	7/1/2016	9/1/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On March 1, 2018, VEP-PG submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R2. VEP-PG did not set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating units as a result of a voltage excursion within the "no trip zone" of PRC-024 Attachment 2 in accordance with the NERC implementation plan. VEP-PG contracted a third party engineering firm to perform an analysis of generator voltage protective relaying settings for its 107 PRC-024-2 applicable generating units. On December 21, 2017, when the PRC-024 lead was reviewing reports provided by the engineering firm, VEP-PG identified that 92 Volts/Hertz relays, which are required to be included in the voltage protective relay setting analysis, were not included in the engineering analysis. As a result, VEP-PG did not meet the required 40% implementation plan requirement by July 1, 2016, the 60% implementation plan requirement by July 1, 2017, or the 80% implementation plan requirement by July 1, 2018. The analysis identified required relay setting changes for five units. The maximum change was a +12.2% difference where the relay setting changed from 1.08 PU with a 10 second time delay to 1.23 PU with a 5 second time delay. As a result of the incorrect settings, the units would have tripped at 1.08 overvoltage for 10 seconds, outside the 4 second limit shown on the Ride-Through Time Duration Curve, which is 1.8% within the no-trip limit of 1.1 PU requirement over 1 second time duration. The primary cause of the noncompliance is a lack of effective internal controls. During its assessment, VEP-PG discovered that the Power Generation Engineering (PGE) Principal Engineer directed the third party to not include Volts/Hertz protection based on the PGE engineer's interpretation of the "Voltage Ride-Through Curve Clarifications" within NERC Reliability Standard PRC-024-2. VEP-PG determined that Power Generation Regulatory Compliance (PGRC) did not provide a detailed scope of work to PGE prior to the start of the evaluations, nor was a thorough Standard review performed to ensure alignment on compliance requirements. In addition, the PGRC subject matter expert did not evaluate the study results prior to the compliance date. The established process during this time did not specify a review deadline that would provide compliance assurance. This noncompliance started on July 1, 2016, when VEP-PG was required to meet the 40% implementation requirement and ended on September 1, 2018, when VEP-PG completed the required relay setting changes.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). VEP-PG's failure to set the generator voltage protective relaying outside of the "no trip zone" could have resulted in up to five units prematurely tripping. However, these five units, which ranged from 83 MW with a 16% capacity factor to 153 MW with a 10% capacity factor, were only a total of 691 MWs of VEP-PG's 20,220 MWs of generation. The analysis determined that only five of the 107 units required relay setting changes. A premature trip of these five units would not have significant impact to the reliability of the BPS. No units tripped as a result of the incorrect relay settings. No harm is known to have occurred. SERC considered VEP-PG's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, VEP-PG: 1) completed the required PRC-024-2 analysis; 2) changed the incorrect relay settings; 3) performed an internal review of program documents to determine how personnel overlooked specific guidance, and if program documents include sufficient guidance with regard to roles, responsibilities, and requirement deliverables. Updated program documents to address identified weaknesses; 4) reviewed scope of work for third party engineering firm to ensure correct methodology. 5) created an Internal Controls document for use by PGRC that identifies roles and responsibilities with regard to PRC-024 program management. This document provides details to ensure the identification, assessment, submittal and documentation of protective relays for compliance with PRC-024; and 6) provided training to PGE and PGRC staff regarding the Internal Controls document and lessons learned.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017018329	FAC-009-1	R1	Virginia Electric and Power Company (DP, TO) (VEP-Trans)	NCR01214	12/6/2010	7/20/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 8, 2017, VEP-Trans submitted a Self-Report stating that, as a Transmission Owner, it was in noncompliance with FAC-009-1 R1. VEP-Trans did not establish Facility Ratings for its Facilities that are consistent with the associated Facility Ratings Methodology. SERC determined that this noncompliance continued into version FAC-008-3 R6 of the Standard and Requirement. In 2010, VEP-Trans completed a project to add a new 230kV transmission line between the Chickahominy and Lanexa substations. To add the new line, VEP-Trans relocated some existing lines to facilitate the use of existing spans of idle conductor. At Chickahominy, line 2024 was one of the existing lines VEP-Trans relocated. The Facility Ratings Database (FRD) identified the limiting element of existing line 2024 as 2-636 aluminum-conductor steel-reinforced (ACSR) cable with a rating of 2,628 amps. During construction, VEP-Trans was unable to install a temporary pole for reconfiguring line 2024 as designed which resulted in field changes to line 2024 that differed from the original design. On November 18, 2010, VEP-Trans took an outage on line 2024 and cut in line 2024 jumpers in two locations between spans of 2-636 ACSR conductor. VEP-Trans installed new jumpers for line 2024 reconnecting line 2024 to a section of existing idle conductor, making that once idle conductor part of line 2024. This is the field change that differed from the original design. VEP-Trans later determined that the formerly idle conductor, now part of line 2024, was 2-721 aluminum-conductor alloy-reinforced (ACAR) cable. On December 6, 2010, VEP-Trans re-energized line 2024 with 2-721 ACAR. Bundled 721 ACAR has an ampacity of 1,812 amps, which is less than the 2-636 ACSR rating of 2,628 amps. On June 22, 2017, during an unrelated field visit to the Lanexa substation, an engineer recognized that VEP-Trans did not update the transmission lines construction one-line after completion of the 2010 project. Therefore, it did not record the field changes for re-configuration of line 2024 in the FRD. Updating the transmission lines construction one-line would have prompted an update to the FRD that the most limiting element of line 2024 was the configuration of 2-721 ACAR with a rating of 1,812 amps. The cause of this noncompliance was the result of failure in human performance and ineffective internal controls. Personnel did not communicate changes made in the field 'as built' and therefore personnel did not record the changes on the construction one-line. The construction one-line is the document of record for ratings of facilities to be recorded (if new), or updated (if changed) from prior existing facilities as recorded in the FRD. As a result, the line rating in the FRD as of December 6, 2010 was incorrect. This noncompliance started on December 6, 2010, when VEP-Trans re-energized line 2024 with 2-721 ACAR, and ended on July 20, 2017, when VEP-Trans entered the correct ratings in the FRD and submitted them to PJM.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Failure to establish correct Facility Ratings may result in improper operational planning and operation of equipment causing damage or reduced lifetime of BPS Facilities. However, the actual capacity of line 2024 is 1,812 amps (summer rating at 100 degrees F). The highest load recorded during the noncompliance was 1,441 amps and occurred for approximately 2.5 hours on March 4, 2011, when the temperature for the day ranged from a low in the 20s degrees F to a high of mid 50s degrees F. Thus, line 2024 would have an even higher ampacity rating due to cooler weather conditions. In addition, VEP-Trans runs numerous studies on a continual basis using real time data and/or projected system configurations, including real time or projected ambient temperatures. No harm is known to have occurred. VEP-Trans had relevant compliance history. However, SERC determined that VEP-Trans's FAC-009-1 R1 compliance history should not serve as a basis for applying a penalty because the primary cause and associated mitigating activities for the prior noncompliances and the instant noncompliance are unrelated or the relevant mitigating activities occurred after this instance of noncompliance began, making it impossible for VEP-Trans to use the mitigation from an older noncompliance in order to prevent the instant noncompliance. Therefore, the causes and mitigating activities for the prior noncompliances could not prevent the instant noncompliance from occurring. In addition, those prior mitigation activities should prevent a noncompliance similar to the instant noncompliance from reoccurring.
Mitigation	To mitigate this noncompliance, VEP-Trans: 1) re-issued the corrected line 2024 Operating One-Line drawing. This correctly identified 2-721 ACAR as the most limiting element; 2) received and validated the ratings in the FRD for Transmission Line 2024 Operating One-Line; 3) issued correct ratings for line 2024 recording them in the FRD; 4) called and emailed ET System Operations Engineering notifying them of the line ratings change resulting in a de-rate of line 2024; 5) submitted to PJM eDART TERM ticket # 695963 decreasing the line 2024 rating to reflect the 2-721 ACAR conductor as the most limiting element; and 6) implemented a new Project Management internal control for a prior noncompliance that would prevent the instance noncompliance from recurring.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017960	TOP-001-3	R13	Public Utility District No. 1 of Chelan County (CHPD)	NCR05338	April 30, 2017	April 30, 2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On July 17, 2017, the entity submitted a Self-Report stating that, as a Transmission Operator (TOP), it was in noncompliance with TOP-001-3 R13. Specifically, on April 30, 2017, at 2:11 PM, the entity's internal Energy Management System (EMS) generated an alarm indicating that 12 minutes had elapsed since the last Real Time Assessment (RTA) was performed at 1:59 PM. However, the entity's System Operators on shift mistakenly believed that they had 30 minutes to complete a RTA from the time of this alarm, rather than the 18 minutes that the alarm indicated. At 2:40 PM, the entity's System Operator logged a manual RTA using the hosted advanced application (HAA) real-time contingency analysis (RTCA); however, they should have been performed the RTA at 2:29 PM, not at 2:40 PM, 11 minutes past the 30-minute requirement of the Standard After reviewing all relevant information, WECC determined the entity failed to ensure that a RTA was performed at least once every thirty minutes, as required by TOP-001-3 R13. The root cause of the noncompliance was the System Operator's incorrect interpretation of the EMS alarm which indicated that he had thirty minutes to perform a RTA, rather than the 18 minutes that the EMS alarm indicated. The noncompliance began on April 30, 2017, at 2:29 PM when the entity failed to ensure that an RTA was performed 30 minutes after the last successful RTA and ended on April 30, 2017, at 2:40 PM when the entity performed an RTA using the Reliability Coordinator's HAA, for a total of 11 minutes.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to ensure that a RTA was performed at least once every thirty minutes The entity implemented good preventive controls to prevent the above noncompliance from occurring. Specifically, the entity implemented an alarm that notified the System Operator that twelve minutes had elapsed since the last valid RTA solution was recorded. This control was designed to be a reminder that time was elapsing and the System Operator needed to prepare for the RTA. Additionally, the entity uses the Reliability Coordinator's RTCA tool to assist in conducting its RTA, which is normally recorded every five minutes, and completes a manual process for the RTA if the tool is unavailable. Further as detective control, every morning the System Operations Manager reviewed all logs from the previous twenty-five hours and discovered the above issue. In addition to the other controls, the entity has implemented good compensating controls. The entity's RC performed a valid RTA of its area and would have notified the entity if the RTA identified a real-time or contingent condition that required actions to prevent an adverse impact the reliability of the western interconnection
Mitigation	1. The entity completed mitigating activities to address its noncompliance and WECC verified the completion of the mitigating activities. 2. To remediate and mitigate this noncompliance, the entity has: a. completed a valid RTA; b. added a visual timer to its EMS displays showing the amount of time that has elapsed since the previous valid solution was recorded; c. updated the alarm language to specify the duration since the valid solution was recorded; and d. added a supplementary alarm to indicate the failure to record a valid RTA after twenty minutes.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019968	MOD-027-1	R2; R2.1; R2.2; R2.3; R2.4; R2.5	Cabrillo Power I LLC (the "Encina Generating Station") (CPI)	NCR05040	7/1/2018	12/11/18	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On July 3, 2018, the entity submitted a Self-Report stating, as a Generator Owner, it was in noncompliance with MOD-027-1 R2. Specifically, the entity discovered that it did not provide a verified active power frequency control model for 30% of the total MVA for its applicable units to its Transmission Planner by July 1, 2018, as required by the Standard. The entity mistakenly understood the retirement schedule for its generating units to be a rolling retirement with individual units being retired as new generating units would come on-line. The entity expected its generating units to be fully retired by the end of 2017. The entity owns four generating units, two of which are exempt from the scope of the issue because they have capacity factors less than 5%, per the Standard. The other two generating units are subject to this instance because they have capacity factors greater than 5%, per the Standard. In December 2017, the Balancing Authority (BA) issued a Capacity Procurement Mechanism (CPM) designation for the two generating units in scope to cover capacity needs in the area for a period of 12 months before the adjacent generating facility was to be commissioned in October 2018. Subsequently, the two generating units in scope would not fully retire until October 2018. Due to the age of the generating units, the entity was unable to use its internal modeling resources. Further, given the limited timeline, the entity was unable to contract a third-party to complete the modeling before the generating units retired in October 2018. After reviewing all relevant information, WECC determined the entity failed to provide for two units, an active power/frequency control model, including documentation and data (as specified in Part 2.1) to its Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1. The root cause of the issue was that the entity misunderstood the timeline for retiring its generating units, as such, insufficient time was allotted to complete the modeling and verification by the required date. This issue began on July 1, 2018, when the Standard became mandatory and enforceable and ended on December 11, 2018, when the entity's generating units were decommissioned, for a total of 164 days.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The entity had good compensating controls. Specifically, the entity had submitted previous active power/frequency control models to the Transmission Planner (TP) before the new version of the Standard came into effect, but they were not verified per the Standard. In addition, the two generating units in scope have had less than 11% operational hours in 2018 thus reducing the potential for harm and the likelihood of harm occurring. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, CPI: 1) decommissioned the generating units; and 2) submitted its formal deregistration request to WECC. CPI has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018019527	TOP-001-3	R13	Northern States Power (Xcel Energy) (NSP)	NCR01020	1/15/2018	1/15/2018	self-log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On April 10, 2018, NSP, a Coordinated Oversight Program participant, submitted a self-log to MRO stating that, as a Transmission Operator, it was in noncompliance with TOP-001-3 R13. NSP, Public Service Company of Colorado (PSCO) (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program. The noncompliance occurred in the operating areas of PSCO. Xcel Energy states that PSCO experienced a loss of its Real Time Assessment (RTA) tool and did not ensure that RTA was being performed during the outage of its tool. The noncompliance was caused by Xcel Energy failing to implement adequate alarming to alert the operator that the RTA tool was not functioning. Xcel Energy used an alarm that would auto-silence after a period of time and the System Operator did not recognize that the RTA tool was not functioning. Xcel Energy reports that the noncompliance was discovered when an individual investigated the auto-silenced persistent alarm. The noncompliance began on January 15, 2018, when an RTA was not performed at least once every thirty minutes and ended approximately 30 minutes after the noncompliance began, when PSCO notified its Reliability Coordinator and asked the Reliability Coordinator to run PSCO's RTA for it.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Xcel Energy states that during the noncompliance, its Reliability Coordinator was performing RTA that included the PSCO system. Additionally, Xcel Energy states that during the noncompliance, the PSCO system did not experience a line or generation trip. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, Xcel Energy: 1) contacted PSCO's Reliability Coordinator and asked it to run PSCO's RTA; 2) reconfigured the alarm to change it from a high priority alarm that auto silenced to a critical priority alarm that would produce sound until silenced by an operator; 3) conducted an event review (training) with System Operators on the event. The mitigation was limited to PSCO.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018019530	IRO-010-1a	R3	Northern States Power (Xcel Energy) (NSP)	NCR01020	10/1/2011	1/24/2018	self-log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On April 10, 2018, NSP, a Coordinated Oversight Program participant, submitted a self-log to MRO stating that, as a Transmission Operator, it was in noncompliance with IRO-010-1a R3. NSP, Public Service Company of Colorado (PSCO) (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program. The noncompliance occurred in the operating areas of PSCO. Xcel Energy states that upon reviewing PSCO's Reliability Coordinator's (RC) data specifications, that it determined that it was not providing all the data from seven required data categories associated with a WECC Transfer Path. The noncompliance was caused by Xcel Energy failing to define clear ownership for providing this data to the RC. The noncompliance began on October 1, 2011, when the standard became enforceable and ended on January 24, 2018, when it began providing all required data to its RC.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Xcel Energy states that the noncompliance impacted less than 2% of the data points that PSCO was providing to its RC. Further, Xcel Energy stated that the missing data points were not associated with an Interconnection Reliability Operating Limit (IROL), a Remedial Action Scheme (RAS), or a Major WECC Transfer Path. Additionally, Xcel Energy states that the missing data points associated with Blackstart Cranking Paths did not impede PSCO from monitoring the status of those paths. Finally, Xcel Energy reports that the actual MW and Total Transfer Capacity (TTC) were being provided to the RC during the noncompliance and the noncompliance did not prevent either itself or the RC from being able to monitor the actual flows for the impacted WECC Transfer Path. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance: 1) PSCO provided the necessary procedures, scheduled MW, and other data points to its RC; 2) PSCO conducted a full evaluation of each obligation in the RC Data Specifications to verify that each was adequately satisfied; 3) NSP and SPS reviewed their RC data specifications and supporting evidence to confirm there were no deficiencies; and 4) PSCO instituted a monthly meeting to review the data specifications with process owners to determine if there were any needed updates.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018019531	FAC-008-3	R6	Northern States Power (Xcel Energy) (NSP)	NCR01020	1/18/2018	2/7/2018	self-log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On April 10, 2018, NSP, a Coordinated Oversight Program participant, submitted a self-log to MRO stating that, as a Transmission Owner, it was in noncompliance with FAC-008-3 R6. NSP, Public Service Company of Colorado (PSCO) (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program. The noncompliance occurred in the operating areas of SPS and NSP. Xcel Energy states that it updated its Facility Ratings Methodology (FRM) on July 18, 2016. Pursuant to Xcel Energy's FRM, it is required to update affected Facility Ratings within 18 months. Xcel Energy failed to review and update 95 of 602 Facilities in the NSP operating system and 24 of 485 Facilities in the SPS operating system within the required 18 months. Xcel Energy was 12 days late in completing all facilities in the NSP operating system and 20 days late in the SPS operating system. The noncompliance was caused by Xcel Energy failing to adequately consider the time it would take to implement the review and did not have in place a process to ensure that the review was completed within the required timeframe. The noncompliance began on January 18, 2018, 18 months after Xcel Energy updated its FRM and ended on February 7, 2018, when it reviewed and updated the Facility Ratings for all Facilities.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk to the NSP system was minimal because per Xcel Energy, none of the 95 Facilities were part of a Remedial Action Scheme (RAS) or an Interconnection Reliability Operating Limit (IROL), and the actual loading of the affected Facilities during the period of noncompliance was only 45% of the maximum Facility Rating. Additionally, four of the Facilities were associated with a Blackstart Cranking Path; three of those Facilities saw a slight increase in ratings and the one that saw a decrease had far more MVA actual capacity (279.7 MVA) than the 60 MVA that would be used during System Restoration. The risk to the SPS system was minimal because per Xcel Energy, none of the 24 Facilities were part of a Blackstart Cranking Path, an IROL, or a RAS. No harm is known to have occurred.
Mitigation	To mitigate this noncompliance, Xcel Energy: 1) reviewed and updated the Facility Ratings for all Facilities; and 2) implemented a new process to use its compliance tracking tool on future FRM updates.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018019965	MOD-026-1	R2	Eastman Cogeneration Limited Partnership (EASTMAN)	NCR01092	7/1/2018	10/17/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 3, 2018, EASTMAN submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-026-1 R2. Specifically, EASTMAN was unable to meet the 30% phased-in implementation by July 1, 2018. EASTMAN reports that there was a water leak that threatened the Facility's restarting capability. EASTMAN states that performing the exciter model testing would increase the possibility of a trip. EASTMAN did not want to take any action that could increase the possibility of a trip while the Facility's ability to restart was threatened. The cause of the noncompliance was that testing could not be performed due to a water leak that impeded the Facility's ability to restart. This noncompliance started on July 1, 2018, when EASTMAN failed to meet the 30% phased-in implementation plan and ended on October 17, 2018, when it reported the verified model data to its Transmission Planner.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. EASTMAN has a single generation Facility that provides power to an associated industrial operation. Additionally, the generation Facility is not associated with any Blackstart resource, a Cranking Path, nor does it have any system restoration responsibilities. Further, the generation Facility connects with two 138 kV tie lines, which were deemed low-risk in an Inherent Risk Assessment (IRA) conducted by SPP RE. No harm is known to have occurred. EASTMAN has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, EASTMAN: 1) repaired the water leak; 2) performed the testing; and 3) reported the verified model to its Transmission Planner.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018019966	MOD-027-1	R2	Eastman Cogeneration Limited Partnership (EASTMAN)	NCR01092	7/1/2018	10/17/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 3, 2018, EASTMAN submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-027-1 R2. Specifically, EASTMAN was unable to meet the 30% phased-in implementation by July 1, 2018. EASTMAN reports that there was a water leak that threatened the Facility's restarting capability. EASTMAN states that performing the governor/turbine and load control or active power/frequency control model testing would increase the possibility of a trip. EASTMAN did not want to take any action that could increase the possibility of a trip while the Facility's ability to restart was threatened. The cause of the noncompliance was that testing could not be performed due to a water leak that impeded the Facility's ability to restart. This noncompliance started on July 1, 2018, when EASTMAN failed to meet the 30% phased-in implementation plan and ended on October 17, 2018, when it reported the verified model data to its Transmission Planner.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. EASTMAN has a single generation Facility that provides power to an associated industrial operation. Additionally, the generation Facility is not associated with any Blackstart resource, a Cranking Path, nor does it have any system restoration responsibilities. Further, the generation Facility connects with two 138 kV tie lines, which were deemed low-risk in an Inherent Risk Assessment (IRA) conducted by SPP RE. No harm is known to have occurred. EASTMAN has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, EASTMAN: 1) repaired the water leak; 2) performed the testing; and 3) reported the verified model to its Transmission Planner.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2018020216	PRC-005-6	R3	Evergreen Gen Lead LLC	NCR11727	04/01/17	11/19/18	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On August 17, 2018, Evergreen Gen Lead LLC (the Entity) submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-005-6, R3. During preparation for its audit, the Entity discovered that it did not perform the minimum maintenance activities for its Vented Lead-Acid (VLA) Batteries in accordance with the maximum maintenance intervals prescribed in PRC-005-6 and the Implementation Plan for PRC-005-6. The Entity owns two wind generation Facilities. • By the April 1, 2017 deadline, the Entity had not completed all of the aspects of the 18-month interval battery maintenance activities for both Facilities. The battery banks at each Facility were last tested in September 2014 and September 2015. Each battery bank should have been tested under the 18 month criteria by April 1, 2017. • The Entity also did not conduct the 6-year battery bank performance verification for one of its two Facilities by December 31, 2017 (the expiration of the maintenance interval). The VLA battery bank performance verification last took place in 2011. The noncompliance started on April 1, 2017, when the Entity was required to have completed the 18-month VLA battery maintenance activities, and ended on November 19, 2018, when the Entity performed all of the required maintenance activities for the VLA batteries and the battery bank. The root cause of this noncompliance was a lack of management oversight around implementing the Protection System Maintenance Program (PSMP) and less than adequate controls for scoping and scheduling PSMP maintenance tasks. A contributing cause was the Entity's change of ownership leading up to and during the PRC-005 transition.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Unmaintained VLA batteries and control circuitry could cause those components to fail when needed and could cause the generator to trip offline, which could potentially exasperate an ongoing real time BES situation. It could expose the generation equipment to damage if the plant fails to trip offline properly when called upon. However, the Entity's generating facilities consist of two wind sites that total to 142 MW at a common BES point of interconnection. The rated capability of the generation is approximately 7% of the Entity's Balancing Authority (ISONE) required Operating Reserve. In addition, the generator operated at capacity factors of 24% in 2017 and 2018. Therefore, the capacity of this unit can be replaced by the ISONE in the event of an unnecessary trip or loss of generating capability. Finally, as a variable energy resource, the site is highly dependent on ambient conditions and the output of the site is contingent on these conditions. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, Evergreen Gen Lead LLC: 1) Completed all of the missing PRC-005 maintenance at both BES facilities 2) Reviewed all PRC-005 maintenance deadlines and added them to its Microsoft Outlook calendar that will alert before the interval due date occurs 3) Added monthly engagement calls with a third-party NERC consultant to ensure ongoing NERC awareness

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2018020452	MOD-025-2	R1	Evergreen Gen Lead LLC	NCR11727	07/01/2016	11/09/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 25, 2018, Evergreen Gen Lead LLC (the Entity) submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2, R1. During preparation for an audit, the Entity discovered that it failed to meet the Real Power testing requirements of MOD-025-2, R1 Attachment 1 prior to the effective date of the Standard, which was July 1, 2016 for it's two BES wind Facilities. The noncompliance started on July 1, 2016 and ended on November 9, 2018 when the real power testing results for both BES Facilities were provided to the Transmission Planner. The root cause of this noncompliance was a lack of management oversight around understanding and implementing the MOD-025 testing program and less than adequate controls to track testing due dates.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The potential risk due to noncompliance with MOD-025-2 R1 is the Transmission Planner having inaccurate information about the generating units when developing planning models to assess BPS reliability. The Entity generating Facilities are two wind sites that total to 142 MW. The rated capability of the generator is approximately 7% of the Entity's Balancing Authority (ISONE) required Operating Reserve. In addition, the generator operated at capacity factors of 24% in 2017 and 2018. Therefore, the capacity of this unit can be replaced by the ISONE in the event of an unnecessary trip or loss of generating capability due to inaccurate information. Finally, as a variable energy resource, the site is highly dependent on ambient conditions and the potential real power output of the site is contingent on these conditions and the site is not typically relied upon to operate at a consistent real power output level. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance: 1) Scheduled and performed the real power testing at both BES facilities 2) Provided the test results to the Transmission Planner 3) Added verification of the Real Power capability to its Microsoft Outlook calendar with an interval period of less than 60 calendar months 4) Added monthly engagement calls with a third-party NERC consultant to ensure ongoing NERC awareness

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2018020453	MOD-025-2	R2	Evergreen Gen Lead LLC	NCR11727	07/01/2016	11/09/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On September 25, 2018, Evergreen Gen Lead LLC (the Entity) submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2, R2. During preparation for an audit, the Entity discovered that it failed to meet the Reactive Power testing requirements of MOD-025-2, R2 Attachment 1 prior to the effective date of the Standard, which was July 1, 2016 for it's two BES wind Facilities. The noncompliance started on July 1, 2016 and ended on November 9, 2018 when the reactive power testing results for both BES Facilities were provided to the Transmission Planner. The root cause of this noncompliance was a lack of management oversight around understanding and implementing the MOD-025 testing program and less than adequate controls to track testing due dates.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The potential risk due to noncompliance with MOD-025-2 R2 is the Transmission Planner having inaccurate information about the generating units when developing planning models to assess BPS reliability. The Entity generating Facilities are two wind sites that total to 142 MW. The rated capability of the generator is approximately 7% of the Entity's Balancing Authority (ISONE) required Operating Reserve. In addition, the generator operated at capacity factors of 24% in 2017 a 2018. Therefore, the capacity of this unit can be replaced by the ISONE in the event of an unnecessary trip or loss of generating capability due to inaccurate information. Finally, as a variable energy resource, the site is highly dependent on ambient conditions and the potential reactive power output of the site is contingent on these conditions and the site is not typically relied upon to operate at a consistent reactive power output level. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance: 1) Scheduled and performed the reactive power testing at both BES facilities 2) Provided the test results to the Transmission Planner 3) Added verification of the Reactive Power capability to its Microsoft Outlook calendar with an interval period of less than 60 calendar months 4) Added monthly engagement calls with a third-party NERC consultant to ensure ongoing NERC awareness

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019020956	COM-002-4	R3	Evergreen Gen Lead LLC	NCR11727	09/05/2016 09/12/2016 05/28/2017	10/14/2016 10/12/2016 06/03/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from October 15, 2018 through January 22, 2019, NPCC determined that Evergreen Gen Lead LLC (the Entity), as a Generator Operator, was in noncompliance with COM-002-4, R3. Specifically, between July 2016 and June 2017, there were three instances where operating personnel were placed in an on-shift position where Operating Instructions could have been given or received prior to those operating personnel completing communication training In all three instances, the Entity could not provide documentation to confirm that the training took place before the operating personnel went on-watch. In all three instances, documentation was provided showing that training was completed approximately one month of assuming the on-shift position. The Entity claimed initial training was performed for the three operating personnel, but that the training records were misplaced during the ownership transition that occurred in 2016. The noncompliance range of dates for the three Operators were from September 5, 2016 to October 14, 2016, from September 12, 2016 to October 12, 2016, and from May 28, 2017 to June 3, 2017. The root cause of this noncompliance was a lack of organization with respect record retention and specifically to the transfer of training records during a change of Facility ownership.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The potential risk due to noncompliance with COM-002-4 R3 is that incorrect actions could be carried out if incorrect or unclear Operating Instructions are delivered or received. However, the Entity generating Facilities are two wind sites that total to 142 MW. The rated capability of the generation is approximately 7% of the Entity's Balancing Authority (ISONE) required Operating Reserve. In addition, the generator operated at capacity factors of 24% in 2017 and 2018. As such, the impact to the BES of the Entity Operator performing an incorrect action due to incorrect communication practices would be minimal. In all three instances, documentation was provided showing that training was completed approximately one month of assuming the on-shift position No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance: 1) The Entity provided documentation that the three Operator's completed the necessary COM-002 training and provided the documentation. 2) The Entity has transitioned its training responsibilities over to the GE Remote Operations Center training process to enhance training oversight and prevent recurrence of the issue. 3) An enhanced training Curriculum Tracker workbook was developed to track the training for all active operators. A new tab is added when new Operators are hired and COM training is refreshed annually for each Operator.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017311	INT-006-4	1	Bonneville Power Administration	NCR05032	November 30, 2016	November 30, 2016	Self Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On March 30, 2017, the entity submitted Self-Reports stating that, as a Balancing Authority (BA) and, it was in noncompliance with INT-006-4 Requirement 1. Specifically, the entity reported that on November 30, 2016, it experienced technical difficulties with its scheduling software used to balance 32,000 MW and 160 interties with neighboring entities. The entity's vendor monitors the system performance and identified the system performance degradation and notified the entity of the issue. The technical issue prevented the entity from approving or denying four e-tags processed as a BA, of its more than 6400 per day, on-time Arranged Interchange e-tags, within the Standard's required timelines. The entity has multiple backup processes in place to ensure that e-tags are processed within the timelines outlined in the Standard if technical issues occur with its scheduling software. However, the technical issues that occurred on the date above prevented the entity from effectively processing these four e-tags within the timelines despite these multiple backup processes. The entity failed to approve or deny four on-time Arranged Interchange that it received as a BA, prior to the expiration of the time period defined in Attachment 1, Column B, as required by INT-006-4 R1. The root cause of these issues was the scheduling software failing to perform as expected. Specifically, end of month maintenance attributed to significant system activity and ultimately the software performance degradation. These issues began on November 30, 2016, when the four on-time Arranged Interchange e-tags were not approved or denied within the requirements of the Standard and ended on November 30, 2016, when the e-tags were approved or denied, and the software returned to normal functionality, for a total of 31 minutes.
Risk Assessment	These issues posed a minimal risk and did not pose a serious and substantial risk to the reliability of the Bulk Power System (BPS). In these instances, the entity failed to approve or deny four on-time Arranged Interchange that it received as a BA, prior to the expiration of the time period defined in Attachment 1, Column B, as required by INT-006-4 R1. The number of e-tags subject to these instances is a small fraction of the total volume of e-tags this entity processes each day. The entity had good detective controls in place. Specifically, the entity's vendor was in the process of reviewing the system performance and investigating key system processes active during the slowdown period to find the root cause, system operations returned to normal approximately 30 minutes after the start of the failure. The entity also has real-time monitoring, control, and contingency analysis in place to ensure that if CPS1 or a BAAL were impacted, the System Operator would act to ensure that the Interconnection frequency is controlled within defined frequency limits.
Mitigation	To mitigate these issues, the entity and the vendor: a. completed an evaluation of maintenance process schedules and implemented necessary adjustments; b. completed the software performance improvements for the most impactful maintenance processes and deployed the improvements to the environment. As these processes are background maintenance processes, and do not change any functionality, the changes were incrementally applied to the system over a period of time; and c. identified software changes to mitigate the impact of such maintenance processes through alternate implementation within its automated scheduling software. These changes will be deployed in its automated scheduling software deployments as the changes are completed following normal processes.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017313	INT-006-4	2	Bonneville Power Administration	NCR05032	November 30, 2016	November 30, 2016	Self-report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On March 30, 2017, the entity submitted Self-Reports stating that, as a Transmission Service Provider (TSP), it was in noncompliance with INT-006-4 Requirement 2. Specifically, the entity reported that on November 30, 2016, it experienced technical difficulties with its scheduling software used to balance 32,000 MW and 160 interties with neighboring entities. The entity's vendor monitors the system performance and identified the system performance degradation and notified the entity of the issue. The technical issue prevented the entity from approving or denying five e-tags processed as a TSP, of its more than 6400 per day, on-time Arranged Interchange e-tags, within the Standard's required timelines. The entity has multiple backup processes in place to ensure that e-tags are processed within the timelines outlined in the Standard if technical issues occur with its scheduling software. However, the technical issues that occurred on the date above prevented the entity from effectively processing these five e-tags within the timelines despite these multiple backup processes. The entity failed to approve or deny five on-time Arranged Interchange it received as a TSP, prior to the expiration of the time period defined in Attachment 1, Column B, as required by INT-006-4 R2. The root cause of these issues was the scheduling software failing to perform as expected. Specifically, end of month maintenance attributed to significant system activity and ultimately the software performance degradation.
Risk Assessment	WECC determined these issues posed a minimal risk and did not pose a serious and substantial risk to the reliability of the Bulk Power System (BPS). In these instances, the entity failed to approve or deny five on-time Arranged Interchange it received as a TSP, prior to the expiration of the time period defined in Attachment 1, Column B, as required by INT-006-4 R2. The number of e-tags subject to these instances is a small fraction of the total volume of e-tags this entity processes each day. The entity had good detective controls in place. Specifically, the entity's vendor was in the process of reviewing the system performance and investigating key system processes active during the slowdown period to find the root cause, system operations returned to normal approximately 30 minutes after the start of the failure. The entity also has real-time monitoring, control, and contingency analysis in place to ensure that if CPS1 or a BAAL were impacted, the System Operator would act to ensure that the Interconnection frequency is controlled within defined frequency limits.
Mitigation	To mitigate these issues, the entity and the vendor: a. completed an evaluation of maintenance process schedules and implemented necessary adjustments; b. completed the software performance improvements for the most impactful maintenance processes and deployed the improvements to the environment. As these processes are background maintenance processes, and do not change any functionality, the changes were incrementally applied to the system over a period of time; and c. identified software changes to mitigate the impact of such maintenance processes through alternate implementation within its automated scheduling software. These changes will be deployed in its automated scheduling software deployments as the changes are completed following normal processes

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017018401	INT-006-4	1	Bonneville Power Administration	NCR05032	July 27, 2017	July 27, 2017	Self-report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 2, 2017, the entity submitted a Self-Report stating that, as a BA, it was in noncompliance with INT-006-4 R1. Specifically, the entity reported that on July 27, 2017, it experienced technical difficulties with its scheduling software used to balance 32,000 MW and 160 ties with neighboring entities. The entity's vendor monitors the system performance and identified the system issue and notified the entity. The technical issue prevented the entity from approving or denying one e-tag processed as a of its more than 6400 per day, on-time Arranged Interchange e-tags, within the Standard's required timelines. The entity has multiple backup processes in place to ensure that e-tags are processed in the timelines outlined in the Standard if technical issues with its scheduling software occur. However, the technical issues that occurred on the date above prevented the entity from effectively processing this one e-tags within the timelines despite these multiple backup processes. After reviewing all relevant information, WECC Enforcement determined the entity failed to approve or deny a single on-time Arranged Interchange that it processed as a BA, received prior to the expiration of the time period defined in Attachment 1, Column B of the Standard, as required by INT-006-4 R1. The root cause of this issue was the scheduling software having technical issues. Specifically, the vendor incident report stated, "After review by additional technical staff, a correlation was made with the deactivation of the AFC Cleanup Process that was completed just prior to the failover on July 27, 2017. It was found that this process, which shares a connection to the database with other processes, was terminating in an unfinished condition and had caused other processes sharing the same connection to also be disrupted. This caused the data delivery process to be impacted, due to the data sequencing requirements of this interface, and subsequent messages were also blocked."
Risk Assessment	WECC determined these issues posed a minimal risk and did not pose a serious or substantial risk to the reliability of the BPS. In this instance, the entity failed to approve or deny a single on-time Arranged Interchange that it processed as a BA, received prior to the expiration of the time period defined in Attachment 1, Column B of the Standard, as required by INT-006-4 R1. The number of e-tags subject to this instance is a small fraction of the total volume of e-tags this entity processes each day and the duration of the issue is of negligible consequence. The entity had good detective controls in place. Specifically, the entity's vendor monitors the system performance and identified the system issue and notified the entity. The entity also has real-time monitoring, control, and contingency analysis in place to ensure that if CPS1 or a BAAL were impacted, the System Operator would act to ensure that the interconnection frequency is controlled within defined frequency limits. Additionally, the software vendor has implemented a safeguard for tickets that are not approved or denied within the defined time requirements and it automatically acted on the e-tag that was not approved or denied and assigned a final status. Because of this safeguard, the entity was only in noncompliance for five minutes. In addition, the vendor has been in use at the entity for over a decade and does have backup processes in place to manage the loss. Lastly, the vendor provides round the clock support to the entity for any system issues that are noticed by the entity's schedulers.
Mitigation	To mitigate these issues, then entity and the vendor: a. assigned a final status to the missed e-tag; and b. repaired the software's data delivery process that caused the failure of the process for the two missed e-tags Due to the significant number of e-tags this entity processes, and the time requirements to approve or deny the requested transactions, an automated software tool is needed to maintain compliance with the Standard. Vendor management and support of the automated software includes the potential for technical issues to arise, and without knowing all future possible technical issues, it is unreasonable to ensure that all future potential non-compliance issues will be prevented. Therefore, WECC is satisfied that the mitigation efforts stated above are sufficient.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017018402	INT-002-4	2	Bonneville Power Administration	NCR05032	July 27, 2016	July 27, 2016	Self-report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 2, 2017, the entity submitted a Self-Report stating that, as a TSP, it was in noncompliance with INT-006-4 2. Specifically, the entity reported that on July 27, 2017, it experienced technical difficulties with its scheduling software used to balance 32,000 MW and 160 ties with neighboring entities. The entity's vendor monitors the system performance and identified the system issue and notified the entity. The technical issue prevented the entity from approving or denying one e-tag processed as a TSP of its more than 6400 per day, on-time Arranged Interchange e-tags, within the Standard's required timelines. The entity has multiple backup processes in place to ensure that e-tags are processed in the timelines outlined in the Standard if technical issues with its scheduling software occur. However, the technical issues that occurred on the date above prevented the entity from effectively processing this e-tag within the timelines despite these multiple backup processes. After reviewing all relevant information, WECC Enforcement determined the entity failed to approve or deny a single on-time Arranged Interchange that it processed as a TSP, received prior to the expiration of the time period defined in Attachment 1, Column B of the Standard, as required by INT-006-4 R2. The root cause of this issue was the scheduling software having technical issues. Specifically, the vendor incident report stated, "After review by additional technical staff, a correlation was made with the deactivation of the AFC Cleanup Process that was completed just prior to the failover on July 27, 2017. It was found that this process, which shares a connection to the database with other processes, was terminating in an unfinished condition and had caused other processes sharing the same connection to also be disrupted. This caused the data delivery process to be impacted, due to the data sequencing requirements of this interface, and subsequent messages were also blocked."
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the BPS. In this instance, the entity failed to approve or deny a single on-time Arranged Interchange that it processed as a TSP, received prior to the expiration of the time period defined in Attachment 1, Column B of the Standard, as required by INT-006-4 R2. The number of e-tags subject to these instances is a small fraction of the total volume of e-tags this entity processes each day and the duration of the issue is of negligible consequence. The entity had good detective controls in place. Specifically, the entity's vendor monitors the system performance and identified the system issue and notified the entity. The entity also has real-time monitoring, control, and contingency analysis in place to ensure that if CPS1 or a BAAL were impacted, the System Operator would act to ensure that the interconnection frequency is controlled within defined frequency limits. Additionally, the software vendor has implemented a safeguard for tickets that are not approved or denied within the defined time requirements and it automatically acted on the e-tag that was not approved or denied and assigned a final status. Because of this safeguard, the entity was only in noncompliance for five minutes. In addition, the vendor has been in use at the entity for over a decade and does have backup processes in place to manage the loss. Lastly, the vendor provides round the clock support to the entity for any system issues that are noticed by the entity's schedulers.
Mitigation	To mitigate these issues, then entity and the vendor: a. assigned a final status to the missed e-tags; and b. repaired the software's data delivery process that caused the failure of the process for the missed e-tag. Due to the significant number of e-tags this entity processes, and the time requirements to approve or deny the requested transactions, an automated software tool is needed to maintain compliance with the Standard. Vendor management and support of the automated software includes the potential for technical issues to arise, and without knowing all future possible technical issues, it is unreasonable to ensure that all future potential non-compliance issues will be prevented. Therefore, WECC is satisfied that the mitigation efforts stated above are sufficient.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020036	TOP-010-1(i)	R1	Eugene Water & Electric Board	NCR05153	4/1/2018	6/13/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 17, 2018, the entity submitted a Self-Report stating, as a Transmission Operator (TOP), it was in noncompliance with TOP-010-1(i) R1, R3, and R4. Specifically, the entity reported that due to internal changes in personnel responsibilities, it did not meet the enforceable date of the Standard despite its efforts to develop a strategy to be compliant by the enforceable date. The entity did not complete the following requirements of TOP-010-1(i) R1, R3, and R4: After reviewing all relevant information, WECC determined the entity failed to: (i) implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time assessments; (ii) implement an Operating Process Procedure to address the quality of analysis used in its Real-time Assessments; and (iii) have an alarm process that provides notifications to its System Operators when a failure of its Real-time monitoring alarm processor has occurred, as required by TOP-010-1(i) R1, R3, and R4 respectively. The root cause of these issues was not adequately tracking whether specific personnel had completed the required tasks, in addition to excluding new or upcoming Standards from the compliance tracking spreadsheet resulting in missed execution of requirements. These issues began when the Standard became mandatory and enforceable and ended when the entity created and implemented an Operating procedure that addressed the quality and analysis of Real-time data necessary to perform its Real-time monitoring and Real-time assessments in addition to creating system alarms to alert its System Operators of any real-time analysis monitoring that has failed, for a total of 74 days.
Risk Assessment	WECC determined these issues posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, the entity failed to: (i) implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time assessments; (ii) implement an Operating Process Procedure to address the quality of analysis used in its Real-time Assessments; and (iii) have an alarm process that provides notifications to its System Operators when a failure of its Real-time monitoring alarm processor has occurred, , as required by TOP-010-1(i) R1, R3, and R4 respectively. As compensation, the entity's system was monitored 24 hours a day, 7 days a week by its Systems Operators and by its RC for 557 MW of load. During the time of 74 days there were no failures of its Real-Time Contingency Analysis system.
Mitigation	The entity completed mitigating activities for all the Requirements and WECC verified the entity's mitigating activities. To remediate and mitigate this issue, the entity has: a. created and implemented its operating procedures; b. updated its system operation procedure; c. issued a dispatch standing order to provide detailed requirements for specific circumstances and operating conditions that may occur on the Transmission System. This standing order also addresses data analysis; d. had a subject matter expert confirm that all procedures were in place and that the training for each system operator includes review of the procedures and monitoring tool; e. trained each system operator on the procedures that were implemented; and f. added tasks to its internal spreadsheet to assure that the monitoring and completion of tasks associated with meeting enforcement dates for new or revised NERC Standards.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020037	TOP-010-1(i)	R3	Eugene Water & Electric Board	NCR05153	4/1/2018	6/13/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a “violation,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 17, 2018, the entity submitted a Self-Report stating, as a Transmission Operator (TOP), it was in noncompliance with TOP-010-1(i) R1, R3, and R4. Specifically, the entity reported that due to internal changes in personnel responsibilities, it did not meet the enforceable date of the Standard despite its efforts to develop a strategy to be compliant by the enforceable date. The entity did not complete the following requirements of TOP-010-1(i) R1, R3, and R4. After reviewing all relevant information, WECC determined the entity failed to: (i) implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time assessments; (ii) implement an Operating Process Procedure to address the quality of analysis used in its Real-time Assessments; and (iii) have an alarm process that provides notifications to its System Operators when a failure of its Real-time monitoring alarm processor has occurred, as required by TOP-010-1(i) R1, R3, and R4 respectively. The root cause of these issues was not adequately tracking whether specific personnel had completed the required tasks, in addition to excluding new or upcoming Standards from the compliance tracking spreadsheet resulting in missed execution of requirements. These issues began when the Standard became mandatory and enforceable and ended when the entity created and implemented an Operating procedure that addressed the quality and analysis of Real-time data necessary to perform its Real-time monitoring and Real-time assessments in addition to creating system alarms to alert its System Operators of any real-time analysis monitoring that has failed, for a total of 74 days.
Risk Assessment	WECC determined these issues posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, the entity failed to: (i) implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time assessments; (ii) implement an Operating Process Procedure to address the quality of analysis used in its Real-time Assessments; and (iii) have an alarm process that provides notifications to its System Operators when a failure of its Real-time monitoring alarm processor has occurred, , as required by TOP-010-1(i) R1, R3, and R4 respectively. As compensation, the entity’s system was monitored 24 hours a day, 7 days a week by its Systems Operators and by its RC for 557 MW of load. During the time of 74 days there were no failures of its Real-Time Contingency Analysis system.
Mitigation	The entity completed mitigating activities for all the Requirements and WECC verified the entity’s mitigating activities. To remediate and mitigate this issue, the entity has: a. created and implemented its operating procedures; b. updated its system operation procedure; c. issued a dispatch standing order to provide detailed requirements for specific circumstances and operating conditions that may occur on the Transmission System. This standing order also addresses data analysis; d. had a subject matter expert confirm that all procedures were in place and that the training for each system operator includes review of the procedures and monitoring tool; e. trained each system operator on the procedures that were implemented; and f. added tasks to its internal spreadsheet to assure that the monitoring and completion of tasks associated with meeting enforcement dates for new or revised NERC Standards.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018020038	TOP-010-1(i)	R4	Eugene Water & Electric Board	NCR05153	4/1/2018	6/13/2018	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 17, 2018, the entity submitted a Self-Report stating, as a Transmission Operator (TOP), it was in noncompliance with TOP-010-1(i) R1, R3, and R4. Specifically, the entity reported that due to internal changes in personnel responsibilities, it did not meet the enforceable date of the Standard despite its efforts to develop a strategy to be compliant by the enforceable date. The entity did not complete the following requirements of TOP-010-1(i) R1, R3, and R4. After reviewing all relevant information, WECC determined the entity failed to: (i) implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time assessments; (ii) implement an Operating Process Procedure to address the quality of analysis used in its Real-time Assessments; and (iii) have an alarm process that provides notifications to its System Operators when a failure of its Real-time monitoring alarm processor has occurred, as required by TOP-010-1(i) R1, R3, and R4 respectively. The root cause of these issues was not adequately tracking whether specific personnel had completed the required tasks, in addition to excluding new or upcoming Standards from the compliance tracking spreadsheet resulting in missed execution of requirements. These issues began when the Standard became mandatory and enforceable and ended when the entity created and implemented an Operating procedure that addressed the quality and analysis of Real-time data necessary to perform its Real-time monitoring and Real-time assessments in addition to creating system alarms to alert its System Operators of any real-time analysis monitoring that has failed, for a total of 74 days.
Risk Assessment	WECC determined these issues posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, the entity failed to: (i) implement an Operating Process or Operating Procedure to address the quality of the Real-time data necessary to perform its Real-time monitoring and Real-time assessments; (ii) implement an Operating Process Procedure to address the quality of analysis used in its Real-time Assessments; and (iii) have an alarm process that provides notifications to its System Operators when a failure of its Real-time monitoring alarm processor has occurred, as required by TOP-010-1(i) R1, R3, and R4 respectively. As compensation, the entity's system was monitored 24 hours a day, 7 days a week by its Systems Operators and by its RC for 557 MW of load. During the time of 74 days there were no failures of its Real-Time Contingency Analysis system.
Mitigation	The entity completed mitigating activities for all the Requirements and WECC verified the entity's mitigating activities. To remediate and mitigate this issue, the entity has: a. created and implemented its operating procedures; b. updated its system operation procedure; c. issued a dispatch standing order to provide detailed requirements for specific circumstances and operating conditions that may occur on the Transmission System. This standing order also addresses data analysis; d. had a subject matter expert confirm that all procedures were in place and that the training for each system operator includes review of the procedures and monitoring tool; e. trained each system operator on the procedures that were implemented; and f. added tasks to its internal spreadsheet to assure that the monitoring and completion of tasks associated with meeting enforcement dates for new or revised NERC Standards.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2019020891	TOP-001-3	R13	Eugene Water & Electric Board	NCR05153	2/17/2018	2/17/2018	Audit	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted December 10, 2018 through December 20, 2018, WECC determined that the entity, as a TOP, had a potential noncompliance with TOP-001-3 R13. On February 17, 2018 at 19:56 PST the entity performed a valid Real-Time assessment (RTA). Per the Requirement of the Standard, the subsequent RTAs were due every 30 minutes, at 20:26 PST and 20:56 PST, etc. The entity utilized the Reliability Coordinator's Hosted Advanced Application (HAA) for performing Real-Time Contingency Analyses (RTCA). However, the RTCA tool was dysfunctional. As a result, the entity did not perform the next valid RTA until 21:07 PST because the entity's operators were not trained on handling functionality issues with the HAA. After reviewing all relevant information, WECC determined that the entity failed to ensure that a RTA was performed at least once every 30 minutes as required by TOP-001-3 R13. The root cause of the issue was that the entity has no alert or notification to the operator that the tool used to perform RTCA had failed and that another method must be used. A contributing cause was the lack of operator training as to how to respond to RTCA tool failures. This issue began on February 17, 2018 at 20:26 PST, 30 minutes after previous valid RTA at 19:56 PST and ended on February 17, 2018 at 21:07 PST when the entity performed a valid RTA, for a total of 41 minutes
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to ensure that a RTA was performed at least once every 30 minutes as required by TOP-001-3 R13. At the time of the issue, the entity had no preventative or detective controls to prevent or detect the noncompliance. However, the entity's system is primarily used to serve its own load and is unlikely to have a substantial impact on neighboring entities in the interconnection. Additionally, the entity does not provide generation to neighboring entities or operate elements of a WECC Major Transfer Path.
Mitigation	The entity completed mitigating activities and WECC verified the entity's mitigating activities. To remediate and mitigate this issue, the entity has: a. added alarms to alert system operators if the RTA monitoring has failed; b. developed a user guide for using the HAA to perform RTCAs; c. issued dispatch standing order providing detailed requirements for specific circumstances and operating conditions that may occur on the Transmission System; d. confirmed that all procedures are in place and that training for each System Operator includes a review of the procedures and monitoring tool; e. completed training for each System Operator for the RC HAA RTCA tool.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017018227	PRC-005-6	R3	Goshen Phase II LLC	NCR11089	7/1/2017	8/1/2017	SR	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On August 17, 2017, GPL submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-005-6 R3. Specifically, GPL discovered that it did not complete specific maintenance activities for two vented lead-acid (VLA) batteries at one substation; including verification of station DC supply voltage, inspection of electrolyte levels, and inspection for unintentional grounds, per the maximum maintenance intervals for the requirements of Table 1-4(a) of the Standard. Due to confusion between the four-month and 18-month testing date intervals, GPL completed the four-month maintenance activities before the March 31, 2017 deadline, on February 17, 2017. The Compliance Task Manager (CTM) incorrectly changed the next four-month maintenance due date to July 31, 2017 instead of the correct date of June 30, 2017. GPL completed the maintenance activities for the two VLA batteries on August 1, 2017 and the maintenance activities reflected no changes or updates to either VLA battery. After reviewing all relevant information, WECC determined that GPL failed to maintain two VLA batteries at one substation that are included within the time-based maintenance program in accordance with the maximum maintenance intervals prescribed within Table 1-4(a) of the Standard. The root cause of the issue was an incorrect assumption by the GPL staff that the maintenance and testing dates in the tracking software were accurate.
Risk Assessment	WECC determined that this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, GPL failed to maintain two VLA batteries at one substation that are included within the time-based maintenance program in accordance with maximum maintenance intervals prescribed within Table 1-4(a) of the Standard. GPL had weak preventative controls to prevent this issue. However, as compensation, when the missed maintenance was completed, no deficiencies were identified for the VLA batteries. Furthermore, the short duration of the issue lessens the risk to the BPS.
Mitigation	To mitigate this issue, GPL: a. completed the required maintenance tasks for the two VLA batteries; b. revised the CTM tasks for batteries to emphasize testing interval at beginning Task Statement; c. revised the CTM task requiring verification of receipt of batteries to add an additional action to also verify the next CTM due date for the 4-month battery maintenance activities; d. revised all PRC-005 related CTM tasks to add "Regulatory Required Task" at the beginning of the task statement for awareness; e. conducted a review of all prior maintenance activities to confirm that no other delays have occurred and verify that all pertinent CTM tasks have the correct due date; and f. prepared and conducted refresher CTM training for Performance Managers and Deputy Performance Managers for each applicable wind farm.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date
WECC2018019007	COM-001-3	R9	Peak Reliability	NCR10289	12/1/2017	12/15/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 19, 2018, the entity submitted a Self-Report stating, as a Reliability Coordinator (RC), it was in noncompliance with COM-001-3 R9. Specifically, the entity reported that during the transition from COM-001-2.1 to COM-001-3, a footnote was inadvertently deleted from its Communications Systems Monitoring and Testing document. The footnote cited the requirement to perform monthly calls to test its Alternative Interpersonal Communication (AIC), through its telephone system, with the entities that do not participate in the daily Balancing Authority (BA) and Transmission Operator (TOP) calls. Although the entity completed its daily BA and TOP calls after the transition to COM-001-3, it did not perform the November 2017 calls with one BA and six TOPs due to the deleted footnote. After reviewing all relevant information, WECC determined the entity failed to test its AIC capability at least once each calendar month, as required by COM-001-3 R9. The root cause of the issue was an incomplete documented process. The entity had inadvertently removed the monthly calls with certain BAs and TOPs from its Communications Systems Monitoring and Testing document in its transition from one version of the Standard to the next version of the Standard. This issue began on December 1, 2017, when the entity did not complete a monthly test of its AIC with the required BAs and TOPs and ended on December 15, 2017, when the entity completed the test of its AIC with each required entity, for a total of 16 days.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to test its AIC capability at least once each calendar month, as required by COM-001-3 R9. However, the entity has effective compensating measures. Specifically, the entity tests its AIC capability daily with the remaining 35 BAs and 56 TOPs, thus reducing the risk. PEAK also has moderate detective controls in its informal process to review the daily call logs performed by the shift foreman and again by the compliance officer.
Mitigation	To remediate and mitigate this issue, the entity has: a. completed an adequate test of its AIC capability with the missed BA and six TOPs; b. revised the Communications Systems Monitoring and Testing process document to return the footnote citing the AIC testing with the entities not participating in the daily BA and TOP calls; and c. created calendar reminders for departmental staff that test the AIC capability through monthly individual calls with the entities not participating in the daily BA and TOP calls.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Mitigation Completion Date
WECC2017018483	PRC-002-2	R5	Peak Reliability	NCR10289	9/28/2016	4/16/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a “violation,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 11, 2017, the entity submitted a Self-Report stating, as a RC, it was in noncompliance with PRC-002-2 R5. Specifically, the entity reported that in August 2017, it discovered its Dynamic Disturbance Recorder (DDR) list had not been sent to all the owners of identified Bulk Electric System (BES) elements within 90 days of completion of the identification of the BES elements that require DDR. The entity did not include one Control Center owner when it sent the DDR list to the other owners of applicable BES elements on June 30, 2016. The missing Control Center had one Facility that requires DDR. The entity updated and disseminated its DDR list to include the missing Control Center on April 16, 2017. After reviewing all relevant information, WECC determined the entity failed to notify one owner of identified BES element, within 90-calendar days of completion of Part 5.1, that its respective BES Elements require DDR data when requested, as required by PRC-002-2 R5. The root cause of the issue was to the lack of an adequate process for the creation and dissemination of the entity’s DDR list. This issue began on September 28, 2016, 90 days after the entity notified all but one BES Element owners for which DDR data is required and ended on April 16, 2017, when the entity notified the control center that was missing from the DDR list that its respective BES Elements require DDR data, for a total of 201 days.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the BPS. In this instance, the entity failed to notify all owners of identified BPS Elements, within 90-calendar days of completion of Part 5.1, that their respective BPS Elements require DDR data when requested, as required by PRC-002-2 R5. However, the entity had good compensating controls. Specifically, the entity posted the list of BES elements which require DDR data to its external, entity facing website. As further compensation, there were no events during the period of noncompliance that would have required the entity to request DDR, and the Control Center missing from the list is not required to install applicable DDR devices until 2022.
Mitigation	To remediate and mitigate this issue, the entity has: a. notified the Control Center owner that was missing from the DDR list of the respective BES elements that require DDR data; b. updated the DDR distribution list to include all applicable owners; and c. created a process for disturbance monitoring and reporting requirements to address the requirements of the Standard.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017018755	IRO-010-2	R1	Peak Reliability	NCR10289	1/1/2017	12/8/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 10, 2017, the entity submitted a Self-Report stating, as a RC, it was in noncompliance with IRO-010-2 R1. Specifically, the entity reported that it did not directly address, in the correct format, its current Protection System status or degradation in its documented specification for the data necessary for the entity to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. This documented specification is both published on the entity's public-facing website and distributed to applicable entities, per IRO-010-2 R1. In the transition from the previous version of IRO-010, the entity did not update the documented specification for the data required by the new version of the Standard, by the mandatory and enforceable date of January 1, 2017. The entity incorrectly assumed the previous version of the document would still qualify for compliance with the Standard. After reviewing all relevant information, WECC determined the entity failed to maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments; including provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability, as required by IRO-010-2 R1. The root cause of the issue was that the entity did not correctly implement the required updates in the documented specification for the data required by the Standard, when the new version of the Standard, IRO-010-2, became mandatory and enforceable. This issue began on January 1, 2017, when IRO-010-2 became mandatory and enforceable and ended on December 8, 2017, when the entity revised its data specification document to include the correct format for provisions for the notification of current Protection System degradation, for a total of 342 days.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious and substantial risk to the reliability of the BPS. In this instance, the entity failed to maintain a documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments; including provisions for notification of current Protection System and Special Protection System status or degradation that impacts System reliability, as required by IRO-010-2 R1. However, the entity implemented effective detective controls in its Compliance Department review of events, which identified this issue. In addition, the entity implemented compensating measures to lessen the risk. Though the entity did not meet the requirements of the Standard, it did communicate with the required entities to provide awareness of Protection System status or degradation that impacts System reliability.
Mitigation	To remediate and mitigate this issue, the entity has: a. revised its data specification document to include provisions for notification Protection System degradation that impacts System reliability; and b. implemented a process to notify members regarding updates to the RC data specification.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017221	COM-002-4	R1	Seattle City Light	NCR05382	7/1/2016	3/27/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible or confirmed violation.)	On March 13, 2017, the entity submitted a Self-Report stating, as a Balancing Authority and Transmissions Operator, it was in issue with COM-002-4 R1. Specifically, the entity reported that its internal procedural documents for communication protocols did not include all the required elements of R1. The entity's procedure neither provided issuance/receipt requirements associated with single-party to multiple-party burst Operating Instructions (R1.4) nor specified instances that require time identification when issuing Operating Instructions (R1.5). After reviewing all relevant information, WECC determined the entity failed to document communications protocols to require operating personnel that issue a written or oral single-party to multiple-party burst Operating Instructions to confirm or verify that the Operating Instruction was received by at least one receive of the Operating Instruction, as well as specify instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification, as required by COM-002-4 R1.4 and R1.5. The root cause of the issue was a less that adequate process and procedure. The entity historically had not needed to issue single-party to multiple party burst Operating Instruction or Operating Instructions across time zones and therefore did not believe that these requirements were applicable. This issue began when the Standard and Requirement became mandatory and enforceable and ended when the entity updated its communications protocol procedures, for a total of 256 days.
Risk Assessment	WECC determined this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, the entity failed to document communications protocols to require operating personnel that issue a written or oral single-party to multiple-party burst Operating Instructions to confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction, , as well as specify instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification, as required by COM-002-4 R1.4 and R1.5. The entity conducted a pre-audit review of compliance with the reliability Standards prior to every audit to detect any potential noncompliance. In addition, the entity has never had to issue a single-party to multiple party burst Operating Instruction and the entity's neighboring TOPs and GOs are in the same time zone as the entity. Hence, the entity would likely not have miscommunication or delayed response due to operation in a different time zone.
Mitigation	The entity submitted a Mitigation Plan to address this issue, WECC accepted the entity's Mitigation Plan. To remediate and mitigate this issue, the entity has: a. revised its communication protocol to include procedures for single-party to multiple-party burst Operating Instructions; b. revised its communications protocol to include procedures to use Pacific Prevailing Time; in 24-hour clock for all communications and when communicating externally across time zones; and c. conducted training for all System Operators in relation to reading the revised communication protocol procedures before shifts. The entity submitted a Mitigation Plan Completion Certification, WECC verified the entity's completion of Mitigation Plan.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
FRCC2019020958	EOP-005-2	R17.	Tampa Electric Company (TEC)	NCR00074	01/01/2018	01/07/2019	Self-Report	Completed
Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed noncompliance.)	On January 22, 2019, TEC submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with EOP-005-2 R17. One (1) out of 37 (2.7%) operators did not receive required two hours training of its Blackstart Resource generation units every two calendar years as required. This noncompliance started on January 1, 2018, when one operator had not received required Blackstart training and ended on January 7, 2019, when the operator received required training. In this instance, the operator was absent for four months (July 14, 2017 to November 16, 2017) during which time he missed the 2017 Blackstart Training class. Makeup training for this operator was overlooked when he returned to work. The issue was discovered by internal review. After the issue was discovered, the operator received training on January 7, 2019, a period of 371 days after it was required. The cause for this noncompliance was a lack of internal controls to ensure operators scheduled for the required training actually received it.							
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk of missed training is that the operator would be lacking in required information necessary to perform a Blackstart system restoration when needed. This risk was reduced as the operator missing the required bi-annual training (i.e., every two calendar years) had received the training in 2013 and 2015, and there have been no substantial changes to the equipment or procedures since his prior training. In addition, there were eight (8) other operators on his crew who had the 2017 training and who were available to perform Blackstart system restoration. No harm is known to have occurred.							
Mitigation	To mitigate this noncompliance, TEC: 1) trained Operator; 2) performed an extent of condition identifying only one out of 37 operators did not receive training in 2017; 3) completed root cause analysis; 4) created preventative controls to add details to work order such as names of those that require training to ensure everyone receives the appropriate training. Work order won't close out until everyone receives training. Added a task for Operations Engineer or Operations Manager to review the list of all Operations teams' personnel to ensure all teams have received this training. Added task to schedule make-up training session as required; 5) created preventative control by updating energy services handbook to include more details; and 6) communicated to personnel the changes to the energy services handbook regarding EOP-005-2 R17.							

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
FRCC2019020949	VAR-002-4.1	R3.	Gainesville Regional Utilities (GRU)	NCR00032	02/10/2018	02/10/2018	Self-Report	06/30/2019
Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed noncompliance.)	On January 18, 2019, GRU submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with VAR-002-4.1 R3. This noncompliance started on February 10, 2018, when GRU failed to notify its Transmission Operator of an Automatic Voltage Regulator (AVR) status change greater than 30 minutes, and ended on February 10, 2018, when the proper notification was made. During an internal audit, GRU discovered the AVR for an 80MW generator had changed from automatic mode to manual mode for a duration of 93 minutes. The change was not communicated to GRU's system control (GRU is both Generator Operator and Transmission Operator) until 63 minutes after the status change occurred. An extent of condition review was completed verifying no additional occurrences. Furthermore, GRU verified while the AVR was out of automatic mode the voltage schedule was maintained. The cause for this noncompliance was inadequate alerting capability of AVR status.							
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. GRU's failure to maintain the AVR in automatic mode could result in excursions from the established voltage schedule, preventing the Transmission Operator from effectively managing voltage. The risk was reduced because of the short duration of the event, and a review of voltage levels during the event revealed no voltage excursions occurred. No harm is known to have occurred.							
Mitigation	To mitigate this noncompliance, GRU: 1) completed an extent of condition review; 2) verified that the AVR out of auto event did not result in an excursion from the voltage schedule; 3) corrected AVR alarm for violating plant; and 4) updated generator operator procedures for VAR-002-4.1. To mitigate this noncompliance, GRU will: 1) create training materials for new system control AVR alarms by March 31, 2019 2) train on generator operator procedures for VAR-002-4.1 by April 30, 2019; 3) train system operators on new AVR alarms by May 30, 2019; 4) create redundant EMS alarm at system control for each unit's AVR status by June 30, 2019; and 5) investigate and correcte AVR alarms for additional plants by June 30, 2019.							

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SPP2016015951	PRC-005-2(i)	R3	Eastman Cogeneration Limited Partnership (EASTMAN)	NCR01092	10/1/2015	3/31/2016	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On July 25, 2016, EASTMAN submitted a Self-Report stating that as a Generator Owner, it was in noncompliance with PRC-005-2(i) R3. EASTMAN also submitted a Self-Report stating that it was in noncompliance with PRC-005-1b R2 (SPP2016015926) on July 21, 2016; both Self-Reports were consolidated into this NERC Violation ID. Under the PRC-005-2(i) R3 implementation plan, EASTMAN was required to be 100% compliant for applicable equipment that has less than a one-year maintenance interval. EASTMAN discovered this noncompliance in preparation for a September 2016 Compliance Audit where PRC-005-2(i) R3 was in scope. EASTMAN identified multiple instances where it failed to perform the four-month maintenance of VLA batteries, verification of communication system functionality, as well as failures to test, inspect, and/or calibrate protection system devices according to EASTMAN's Protection System Maintenance Program (PSMP). The cause of the noncompliance was that EASTMAN had inadequate internal controls to implement its PSMP and a lack of understanding between internal departments regarding their responsibilities. The noncompliance began on October 1, 2015, when the implementation plan required 100% compliance, and ended on March 31, 2016, when all required maintenance activities were completed.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. EASTMAN has a single generation Facility that was commissioned in 2001 and has not had any PRC-005-2(i) related events or protection system dc supply problems during the life of the plant. Additionally, the generation Facility is not associated with any Blackstart resource, a Cranking Path, nor does it have any system restoration responsibilities. Further, the generation Facility connects with two 138 kV tie lines, which were deemed low-risk in an Internal Risk Assessment (IRA) conducted by SPP RE. No harm is known to have occurred. MRO considered EASTMAN's relevant compliance history. EASTMAN's PRC-005-2(i) R3 compliance history includes minimal risk violations of PRC-005-1 R1 (SPP201000297) and PRC-005-1 R2 (SPP201000298). The PRC-005-1 R1 violation involved a failure to have a complete PSMP and include all components within its PSMP; the noncompliance was mitigated on December 15, 2011. The PRC-005-1 R2 violation involved a failure to test four relays within the three-year interval and have testing documentation for the majority of its other components such as battery banks, instrument transformers, and dc control circuits; the noncompliance was mitigated on June 1, 2012. MRO determined that EASTMAN's compliance history should not serve as a basis for applying a penalty. MRO determined that the current noncompliance was not caused by a failure to mitigate the prior instances of noncompliance and there is a substantial duration of time between the current noncompliance and the prior instances of noncompliance.
Mitigation	To mitigate this noncompliance, EASTMAN: 1) confirmed the October 2017 shutdown schedule; 2) performed the East/West line differential Protective Relay and Communications Maintenance; 3) performed relay and dc control circuit maintenance; 4) performed six-year interval for dc supply maintenance; 5) purchased a new dc supply; 6) confirmed the maintenance schedule with its contractor; and 7) installed new dc supply line on unit 2. The associated Mitigation Plan was verified on May 11, 2018.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018019528	PRC-005-6	R3	Northern States Power (Xcel Energy) (NSP)	NCR01020	04/01/2017	02/28/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On April 10, 2018, NSP, a Coordinated Oversight Program participant, submitted a self-log to MRO stating that, as a Transmission Owner, it was in noncompliance with PRC-005-6 R3. NSP, Public Service Company of Colorado (PSCO) (NCR05521), and Southwestern Public Service Company (SPS) (NCR01145) (hereafter referred to collectively as Xcel Energy) are Xcel Energy companies monitored together under the Coordinated Oversight Program. The noncompliance occurred in the operating areas of NSP and PSCO. Xcel Energy states that it discovered that it had missed an 18-month maintenance activity (testing) for a dc supply at one NSP substation. Xcel Energy reports that it conducted an extent of conditions review at all substations subject to dc supply maintenance and verification requirements. The review did not reveal any additional noncompliance with an 18-month maintenance activity, but did identify noncompliance associated with four-month maintenance activities (inspections) at 13 NSP substations and 12 PSCO substations. The cause of the noncompliance was that Xcel Energy experienced issues in the implementation of a new work order system and Xcel Energy's Maintenance Program procedure lacked controls and oversight to ensure that testing was completed within the appropriate timeframes. The noncompliance began on April 1, 2017 when Xcel Energy missed the first four-month maintenance activity and ended on February 28, 2018 when Xcel Energy performed all required maintenance activities.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Xcel Energy reports the dc supplies have alarms for loss of ac or high/low voltage alarms and alarms for grounds; these alarms are designed to alert Xcel Energy prior to a failure. Xcel Energy states that it did not receive any alarms or experience any dc supply failures during the period of noncompliance. Additionally, none of these substations are associated with an IROL, a WECC Major Path, or a Remedial Action Scheme (RAS). No harm is known to have occurred.
Mitigation	To mitigate the noncompliance, Xcel Energy: To mitigate the noncompliance to the 18-month maintenance activities, Xcel Energy: 1) completed the required testing; 2) updated its Substation Battery Maintenance and Testing Program to include additional controls and oversight; 3) added substation dc supply test requirements to its compliance milestones; and 4) provided training to Substation O&M staff. To mitigate the noncompliance related to the four-month maintenance activities, Xcel Energy: 1) completed the required inspections; 2) implemented auto-generation of work orders of substation dc supply inspections; 3) updated substation dc supply inspection work orders to require the inspection of dc supply voltage, electrolyte level, and unintentional grounds; 4) setup monthly tasks in its internal corporate task tracking tool for substation O&M managers to review inspection reports; and 5) provided training to substation O&M staff on battery testing/inspection requirements.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
MRO2018020440	FAC-008-3	R3	Southern Minnesota Municipal Power Agency (SMMPA)	NCR01030	01/01/2013	06/28/2018	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	During a Compliance Audit conducted on January 24, 2018, MRO determined that SMMPA, as a Transmission Owner, was in noncompliance with FAC-008-3 R3. One or more of SMMPA's substations contain equipment in bus segments that are not series-connected with adjacent Transmission Lines during normal operations, however the equipment does become series-connected during certain substation configurations (e.g., when any of the circuit breakers on the ring bus are open). MRO originally considered this an Area of Concern, but determined that noncompliance existed once it was confirmed that certain substation configurations had actually occurred in which the equipment had become series-connected. An extent of condition review determined that since January 1, 2015 abnormal configurations occurred in eight instances at the Byron 345 kV substation where equipment on its ring bus became series connected. MRO determined that during these abnormal configurations, the applicable Facility Rating should have been reduced from 2000 Amps to 1600 Amps, but new ratings were not issued. SMMPA's Facility Ratings methodology failed to ensure valid Facility Ratings during these abnormal configurations by either having a requirement that 1) ensured that the Ratings of such equipment be reflected in the Facility Ratings of the adjacent line terminals; or 2) provided temporary Facility Ratings during the substation configuration changes that cause the equipment to become series-connected. The cause of the noncompliance is that SMPPA's Facility Ratings methodology did not consider situations where Facility reconfiguration could affect which equipment was series-connected, leading to a modification in the Facility Rating. The noncompliance began on January 1, 2013, when the Standard became enforceable, and ended on June 28, 2018 when SMMPA updated its Facility Ratings methodology and issued new Facility Ratings.
Risk Assessment	The noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. SMMPA was following ERO guidance in developing its Facility Ratings methodology, the ERO guidance is not clear with respect to non-series equipment that could become the most limiting element during a Facility reconfiguration. Additionally, the Byron substation is SMMPA's only 345 kV Facility, and is not part of an IROL or Blackstart Cranking Path. Finally, there were no reported outages or equipment damage as a result of the noncompliance. No harm is known to have occurred. SMMPA has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, SMMPA: 1) revised its Facility Ratings methodology to include considerations of unique substation configurations; and 2) issued new Facility Ratings for the impacted terminals.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SPP2018019268	COM-002-4	R4	Southwestern Power Administration (SWPA)	NCR01144	7/1/2017	9/19/2017	Self-Certification	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On February 28, 2018, SWPA submitted a Self-Certification stating that as a Transmission Operator, it was in noncompliance with COM-002-4 R4. During an internal review, SWPA determined that its assessment did not include all the documented communications protocols listed in R1. SWPA states it only reviewed oral communications protocols. The cause of the noncompliance was that SWPA failed to understand its compliance obligations under the updated Standard and failed to capture the increased scope of the assessment in the updated Standard language. The noncompliance began on July 1, 2017, when the Standard became enforceable, and ended on September 19, 2017, when a full assessment was completed.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. Per SWPA, supervisory staff perform a daily review of Dispatcher E-logs and Special Conditions reports, which use SWPA's communication protocols. No harm is known to have occurred. SWPA has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, SWPA: 1) assessed each component of its Operating Personnel Communications Protocol; its Operating Personnel Communications Protocol; 2) had its Compliance Division and Chief Dispatcher develop a spreadsheet that identifies all Operation Personnel Communications Protocols that must be assess annually; 3) had its Chief Dispatcher develop another spreadsheet to identify which Operation Personnel will be assessed each quarter to ensure that all personnel are fully assessed by the 12-month deadline; and 4) had its Chief Dispatcher set calendar reminders to conduct the quarterly assessments.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SPP2018019399	VAR-002-4.1	R2	Thunder Ranch Wind Project, LLC (TRW)	NCR11778	1/15/2018	1/16/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On March 19, 2018, TRW submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with VAR-002-4.1 R2. TRW reported that it failed to follow the voltage control schedule provided by its Transmission Operator from January 15 to January 16, 2018. Per TRW, this occurred when the voltage controller inadvertently switched into voltage control mode. This occurred while contractors were working on the SCADA system; during that work the SCADA system defaulted to its normal mode of operations, which included the voltage controller being set to voltage control mode. TRW states that the contractors did not inform the control room of the change and that no alarm was triggered by the change. Because of the change, TRW was no longer maintaining a 0 MVar target as required by its Transmission Operator. The noncompliance was caused by inadequate alarming for a voltage control status and that TRW did not have a process to ensure that contractors notified the control room of changes to the SCADA system. The noncompliance began at approximately 9:00 p.m. on January 15, 2018, when the voltage controller switched modes and TRW no longer maintained the target set by its Transmission Operator, and ended on January 16, 2018 at approximately 5:00 p.m. when TRW returned the voltage controller back to the correct mode and achieved the target set by its Transmission Operator.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The generation Facility could only have a minor impact on the bulk power system as it has a nameplate rating of 300 MW. Additionally, the generation Facility is not part of a Remedial Action Scheme (RAS) and is not associated with any Interconnection Reliability Operating Limit (IROL). No harm is known to have occurred. TRW has no relevant history of noncompliance.
Mitigation	To mitigate this noncompliance, TRW: 1) set the voltage controller back to the correct mode; 2) created a "Return to normal Voltage Controller Alarm" that identifies deviations from the mode of operation required by the Transmission Operator, this alarm must be acknowledged by the operator; 3) updated its "Wind Control System User Administration Policy" and implemented a procedure for all contractors to follow, this procedure will place controls on how contractors access the SCADA system and ensure that the control room is notified of changes to the system; and 4) conducted training with applicable staff on the updated policy.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019020920	MOD-025-2	R1	GenConn Energy LLC	NCR11710	7/1/2016	6/29/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On January 11, 2019, GenConn Energy LLC (GenConn) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with MOD-025-2, R1. GenConn Energy LLC is a subsidiary of NRG Energy, Inc. (NRG). As the July 1, 2016 deadline approached to have 40% of their applicable Facilities tested, the NRG corporate methodology was to calculate the MOD-025-2 implementation plan percentage on a fleet wide basis by Interconnection and not on an NCR basis. As of July 1, 2016, NRG had applicable facilities under 2 NCRs that are now under GenConn Energy LCC NCR11710 and neither NCR met the 40% deadline on July 1, 2016 for its applicable facilities. At the end of 2016, NRG made registration changes with NPCC that eliminated all of the 2016 NCRs and replaced them with two new NCRs. GenConn (NCR11710) is one of those NCRs. In early, 2017, NRG adjusted it's methodology in an attempt to meet the upcoming 60% testing threshold for the July 1, 2017 deadline for MOD-025-2. By July 1, 2018, GenConn had 100% of their applicable facilities tested. The violation start date is July 1, 2016 and ended on June 29, 2018 when the MOD-025-2 R1 real power capability was verified via testing. The root cause of this noncompliance was the decision of NRG corporate compliance to adopt a methodology that calculated the MOD-025-2 implementation plan percentages on a fleet wide basis by Interconnection; and not on the correct NCR basis.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Noncompliance with MOD-025-2 R1 has the potential to affect the reliability of the BPS by allowing for the TP to have inaccurate information about the capabilities of the generating units in planning models used to assess BPS reliability. In the ISO-NE market, real and reactive power testing on the GenConn units that closely matches MOD-025-2 has been regularly verified, reported, communicated, and approved by the ISOs/Transmission Planners to validate generator capability. Although the original documentation provided to ISO-NE may not meet full compliance with the requirement, the potential and actual risks to the BES are low as much of the relevant data needed by the TP was verified, valid, tested, and provided on a consistent basis in previous years. The Net Capacity Factors (NCF) of the 8 GenConn units (480 MW total) are well below 2% from 2014 through 2016 with little change through 2017. Additionally, the result of the verification made in accordance with R1 required no adjustments to the units. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, GenConn: 1) Adjusted its corporate calculation methodology to coincide with the March 24, 2017 NERC CMEP Practice Guide on Implementation Plan percentage calculations 2) Completed the necessary MOD-025-2 R1 testing and then provided the results to the TP.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019020919	MOD-025-2	R2	GenConn Energy LLC	NCR11710	7/1/2016	6/29/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On January 11, 2019, GenConn Energy LLC (GenConn) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with MOD-025-2, R2. GenConn Energy LLC is a subsidiary of NRG Energy, Inc. (NRG). As the July 1, 2016 deadline approached to have 40% of their applicable Facilities tested, the NRG corporate methodology was to calculate the MOD-025-2 implementation plan percentage on a fleet wide basis by Interconnection and not on an NCR basis. As of July 1, 2016, NRG had applicable facilities under 2 NCRs that are now under GenConn Energy LCC NCR11710 and neither NCR met the 40% deadline on July 1, 2016 for its applicable facilities. At the end of 2016, NRG made registration changes with NPCC that eliminated all of the 2016 NCRs and replaced them with two new NCRs. GenConn (NCR11710) is one of those NCRs. In early, 2017, NRG adjusted it's methodology in an attempt to meet the upcoming 60% testing threshold for the July 1, 2017 deadline for MOD-025-2. By July 1, 2018, GenConn had 100% of their applicable facilities tested. The violation started on July 1, 2016 and ended on June 29, 2018 when the MOD-025-2 R2 reactive power capability was verified via testing. The root cause of this noncompliance was the decision of NRG corporate compliance to adopt a methodology that calculated the MOD-025-2 implementation plan percentages on a fleet wide basis by Interconnection; and not on the correct NCR basis.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Noncompliance with MOD-025-2 R2 has the potential to affect the reliability of the BPS by allowing for the TP to have inaccurate information about the capabilities of the generating units in planning models used to assess BPS reliability. In the ISO-NE market, real and reactive power testing on the GenConn units that closely matches MOD-025-2 has been regularly verified, reported, communicated, and approved by the ISOs/Transmission Planners to validate generator capability. Although the original documentation provided to ISO-NE may not meet full compliance with the requirements, the potential and actual risks to the BES are low as much of the relevant data needed by the TP was verified, valid, tested, and provided on a consistent basis in previous years. The Net Capacity Factors (NCF) of the 8 GenConn units (480 MW total) are well below 2% from 2014 through 2016 with little change through 2017. Additionally, the result of the verification made in accordance with R2 required no adjustments to the units. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, GenConn: 1) Adjusted its corporate calculation methodology to coincide with the March 24, 2017 NERC CMEP Practice Guide on Implementation Plan percentage calculations 2) Completed the necessary MOD-025-2 R2 testing and then provided the results to the TP.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019020918	PRC-019-2	R1	GenConn Energy LLC	NCR11710	7/1/2016	6/30/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On January 11, 2019, GenConn Energy LLC (GenConn) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with PRC-019-2, R1. GenConn Energy LLC is a subsidiary of NRG Energy, Inc. (NRG). As the July 1, 2016 deadline approached to have the protection system and voltage regulating control system verified on 40% of their applicable Facilities, the NRG corporate methodology was to calculate the PRC-019-2 implementation plan percentage on a fleet wide basis by Interconnection and not on an NCR basis. As of July 1, 2016, NRG had applicable facilities under 2 NCRs that are now under GenConn Energy LCC NCR11710 and neither NCR met the 40% verification deadline on July 1, 2016 for its applicable facilities. At the end of 2016, NRG made registration changes with NPCC that eliminated all of the 2016 NCRs and replaced them with two new NCRs. GenConn (NCR11710) is one of those NCRs. In early, 2017, NRG adjusted it's methodology in an attempt to meet the upcoming 60% verification threshold for the July 1, 2017 deadline for PRC-019-2. By July 1, 2017, GenConn had 100% of their applicable facilities verified. The violation started on July 1, 2016 and ended on June 30, 2017 when the PRC-019-2 R1 verification that brought GenConn into compliance was completed. The root cause of this noncompliance was the decision of NRG corporate compliance to adopt a methodology that calculated the PRC-019-2 implementation plan percentages on a fleet wide basis by Interconnection; and not on the correct NCR basis.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The failure to verify the coordination of the protection system with the in-service limiters could cause an unnecessary trip, or failure to trip of the unit. However, the result of the June 2017 verification made in accordance with R1 required no adjustments to the units. The Net Capacity Factors (NCF) of the eight GenConn units (8 * 60 MW = 480 MW total) are well below 2% from 2014 through 2016 with little change through 2017. The BA (ISO-NE) carries operating reserves of approximately 2,300 MW of which a GenConn unit is less than 2%. Therefore, if this instance of noncompliance had caused any of the affected generators to trip unnecessarily, the BA would have been able to replace the lost capacity. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, GenConn: 1) Adjusted its corporate calculation methodology to coincide with the March 24, 2017 NERC CMEP Practice Guide on Implementation Plan percentage calculations 2) Completed the necessary PRC-019-2 verification.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019020917	PRC-024-2	R2	GenConn Energy LLC	NCR11710	7/1/2016	6/30/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On January 11 2019, GenConn Energy LLC (GenConn) submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with PRC-024-2, R2. GenConn Energy LLC is a subsidiary of NRG Energy, Inc. (NRG). As the July 1, 2016 deadline approached to have the protection system and voltage regulating control system verified on 40% of their applicable Facilities, the NRG corporate methodology was to calculate the PRC-024-2 implementation plan percentage on a fleet wide basis by Interconnection and not on an NCR basis. As of July 1, 2016, NRG had applicable facilities under 2 NCRs that are now under GenConn Energy LCC NCR11710 and neither NCR met the 40% verification deadline on July 1, 2016 for its applicable facilities. At the end of 2016, NRG made registration changes with NPCC that eliminated all of the 2016 NCRs and replaced them with two new NCRs. GenConn (NCR11710) is one of those NCRs. In early, 2017, NRG adjusted it's methodology in an attempt to meet the upcoming 60% verification threshold for the July 1, 2017 deadline for PRC-024-2. By July 1, 2017, GenConn had 100% of their applicable facilities verified. The violation started on July 1, 2016 and ended on June 30, 2017 when the PRC-024-2 R2 verification that brought GenConn into compliance was completed. The root cause of this noncompliance was the decision of NRG corporate compliance to adopt a methodology that calculated the PRC-019-2 implementation plan percentages on a fleet wide basis by Interconnection; and not on the correct NCR basis.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). The failure to verify the relay settings to the voltage curve could cause the unit to trip at a time when it could exasperate a system event further. However, the result of the June 2017 verification made in accordance with R2 required no adjustments to the units. The Net Capacity Factors (NCF) of each of the eight GenConn units (8 * 60 MW = 480 MW total) are well below 2% from 2014 through 2016 with little change through 2017. The BA (ISO-NE) carries operating reserves of approximately 2,300 MW of which a GenConn unit is less than 2%. Therefore, if this instance of noncompliance had caused any of the affected generators to trip unnecessarily during a system voltage event, the BA would have been able to replace the lost capacity. No harm is known to have occurred as a result of this noncompliance. NPCC considered the Entity's compliance history and determined that there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, GenConn: 1) Adjusted its corporate calculation methodology to coincide with the March 24, 2017 NERC CMEP Practice Guide on Implementation Plan percentage calculations 2) Completed the necessary PRC-024-2 verification on all of the applicable facilities.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019021075	PRC-019-2	R2	Taunton Municipal Lighting Plant	NCR07214	12/03/2018	12/10/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On February 20, 2019, Taunton Municipal Lighting Plant ("Taunton" or "the entity") submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2, R2. Specifically, the entity discovered on December 6, 2018 that it did not re-coordinate within 90 days it's voltage regulating system controls as a result of generator exciter limiter setting changes that were made on September 4, 2018. The noncompliance associated with the needed re-coordination started on December 3, 2018 and ended on December 10, 2018, when the re-coordination was completed by a third party engineering firm. Although the entity had a documented Protection System Maintenance Plan (PSMP), the root cause of this noncompliance was a lack of the development of proper controls around the expected actions and communications for limiter, AVR, and protection system re-coordination when such adjustments are made.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. A lack of coordination amongst the Protection System and the in-service limiters could cause an unnecessary trip of the affected Generating Station. However, the entity's generating facilities total to 130 MW. The rated capability of the generation is approximately 7% of the Entity's Balancing Authority (ISONE) required Operating Reserve. In addition, the generator operated at capacity factors of 8% in 2017 and 11% in 2018. Therefore, the capacity of this unit can be replaced by the ISONE in the event of an unnecessary trip or loss of generating capability. Finally, the results of the December 10, 2018 coordination study showed there were no settings changes needed. No harm is known to have occurred as a result of this of noncompliance. NPCC considered the Entity's compliance history and determined there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) Completed the re-coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection System. 2) Created a tracking spreadsheet for all applicable Reliability Standards with recurring compliance due dates. 3) Entered compliance due dates into the Primary Compliance Contact and immediate supervisor's Microsoft Outlook calendars to ensure future due dates are met. 4) Instituted six-month meetings where the Primary Compliance Contact and subject matter experts from Engineering and Operations will meet to review the compliance obligations of applicable Reliability Standards which include technical requirements. 5) Instituted monthly communication reviews (in-person or conference call) to discuss changes to entity generating unit or plant capabilities, voltage regulating controls, and protection system. Compliance, Engineering, and Operations participate in these reviews that will allow for ample time to properly coordinate these settings, if needed.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2019021076	PRC-005-6	R3	Taunton Municipal Lighting Plant	NCR07214	09/01/2018	01/28/2019	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On February 20, 2019, Taunton Municipal Lighting Plant ("Taunton" or "the entity") submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-005-6, R3. Specifically, the entity missed an 18-month VLA battery inspection. On January 4, 2019, it was discovered upon internal review that 18-month battery testing activity that had last been completed on February 27, 2017 and had not been completed again by September 1, 2018. Upon discovery, the entity coordinated to have the missed battery maintenance completed on January 28, 2019. The noncompliance associated with the 18-month battery testing intervals started on September 1, 2018 and ended on January 28, 2019 when the maintenance was completed. Although the entity had a documented PSMP, the root cause of this noncompliance was a lack of the development of proper controls around employing a reminder or notification system to ensure that this task was completed within 18 calendar months after the February 27, 2017 testing.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The potential risk due to uncompleted PRC-005-6 R3 maintenance is that the entity generation could possibly trip offline prematurely which could exasperate an ongoing real time BES situation. It could also expose the plant equipment to damage if the plant fails to trip offline properly when called upon. However, the entity generating facilities total to 130 MW. The rated capability of the generation is approximately 7% of the Entity's Balancing Authority (ISONE) required Operating Reserve. In addition, the generator operated at capacity factors of 8% in 2017 and 11% in 2018. Therefore, the capacity of this unit can be replaced by the ISONE in the event of an unnecessary trip or loss of generating capability. Although the 18-month battery testing was performed approximately 4 months late, the entity had no known issues with any of their battery systems and or indication that a battery system failure was imminent. No harm is known to have occurred as a result of this of noncompliance. NPCC considered the Entity's compliance history and determined there are no prior relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) Completed the required 18-month interval battery testing per PRC-005-6, Attachment A, Table 1-4(a). 2) Created a tracking spreadsheet for all applicable Reliability Standards with recurring compliance due dates. 3) Entered compliance due dates into the Primary Compliance Contact and immediate supervisor's Microsoft Outlook calendars to ensure future due dates are met. 4) Instituted six-month meetings where the Primary Compliance Contact and subject matter experts from Engineering and Operations will meet to review the compliance obligations of applicable Reliability Standards which include technical requirements.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019908	PRC-019-2	R1	American Electric Power Service Corporation as agent for Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company, AEP Ohio Transmission Company, AEP Appalachian Transmission Company, AEP West Virginia Transmission Company, AEP Indiana Michigan Transmission Company and AEP Kentucky Transmission Company, Inc. (AEPSC)	NCR00682	7/1/2017	4/5/2018	Self-Report	Complete

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On June 11, 2018, AEPSC submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2 R1. ACPSC submitted the Self-Report to ReliabilityFirst under an existing multi-region registered entity agreement on behalf of AEP as Agent for AEP OK Transco., PSCO, and SWEPCO (AEP West) (NCR01056). The phased implementation plan for PRC-019-2 R1 requires that each Generator Owner verify at least 40% of its applicable Facilities by July 1, 2016; 60% of its applicable Facilities by July 1, 2017; 80% of its applicable Facilities by July 1, 2018; and 100% of its applicable Facilities by July 1, 2019. Because of AEP West's efforts to meet the 80% milestone due by July 1, 2018, AEP West completed a fleet-wide compliance assurance evaluation of all facilities including the already completed facilities that were documented to meet prior implementation deadlines. From this review, AEP West determined that its Northeastern Unit 3 did not meet the intent of PRC-019-2 R1.1 (AEP West determined that the applicable loss of field protective function enabled within the overall differential and generator protection microprocessor relays for Northeastern Unit 3 did not meet the intent of PRC-019-2 Requirement R1.1.1. Specifically, the loss of field protective relays were set to operate before the voltage regulator minimum excitation limiter settings. AEP West completed this evaluation on June 25, 2017 and that resulted in a lack of time for AEP Generation to conduct the comprehensive quality assurance review and technical evaluation of the coordination study following field data collection.) and could not be considered as part of AEP Generation's percentage of completed facilities utilized to meet the 60% milestone due by July 1, 2017. Due to the exclusion of Northeastern Unit 3, the resulting percentage of completed PRC-019-2 applicable facilities within the SPP (now MRO) footprint fell below 60% to 59.1% and resulted in this noncompliance. This noncompliance involves the management practices of planning and verification. AEP West determined the cause of this noncompliance to be that it allowed itself insufficient time to conduct a quality assurance review and technical evaluation of the coordination study following field data collection, issue the settings to correct the discoordination issue, and implement changes within a scheduled outage of sufficient duration prior to the milestone due date. This failure to adequately plan and to verify that AEP West had completed 60% of its applicable Facilities are both root causes of this noncompliance. This noncompliance started on July 1, 2017, when AEP West was required to have verified at least 60% of its applicable Facilities and ended on April 5, 2018, when AEP West finished its verification at Northeastern Unit 3.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this noncompliance is the discoordination of voltage control, which can result in a generator falsely tripping. The risk is minimized because AEP West conducted an evaluation of unit operating conditions over the duration of this noncompliance. That evaluation indicated that operation was solely in the over-excited region and would not impact the set points associated with the loss of excitation protective relaying. PRC-019-2 R1 required AEP West to complete verification of 60% of its applicable facilities by July 1, 2017 and AEP West completed 59.1% by July 1, 2017. Missing this one applicable facility only slightly reduced AEP West below the 60% threshold, which minimizes the risk. No harm is known to have occurred. As of July 1, 2018, AEP West had 81.8% of applicable facilities verified in the SPP/MRO footprint which helps reduce the risk while mitigation is ongoing. The entity has relevant compliance history. However, ReliabilityFirst determined that the entity's compliance history should not serve as a basis for applying a penalty because of the different causes of the prior noncompliance and the current noncompliance.
Mitigation	To mitigate this noncompliance, AEP West:

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019908	PRC-019-2	R1	American Electric Power Service Corporation as agent for Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company, AEP Ohio Transmission Company, AEP Appalachian Transmission Company, AEP West Virginia Transmission Company, AEP Indiana Michigan Transmission Company and AEP Kentucky Transmission Company, Inc. (AEPSC)	NCR00682	7/1/2017	4/5/2018	Self-Report	Complete
			1) performed the coordination study following revision and implementation of the Northeastern unit 3 relay settings and this serves as the initial corrective action to allow AEP West to maintain the schedule adherence of the implementation milestones; 2) performed an extent of condition review to ensure the coordination is in compliance on the remaining facilities completed for 60% and 80% milestones. As well as an extent of condition review on the upcoming 100% milestone plan for the remaining applicable facilities to ensure the adequate time for the settings retrieval, coordination, and implementation of settings changes as required per Requirement R1; 3) adjusted the existing plan to allocate additional time to retrieve and analyze the protective relay and automatic voltage regulator limiter settings, and implement changes during the scheduled unit outage to prevent recurrence; and 4) identifed the remaining PRC-019 applicable relays, evaluate associated settings, and updates within the Asset Management Database to aid the future coordination planning. This will allow future planning to save time in identifying applicable relays and obtaining the necessary field settings. In turn, this will reduce the time needed for the PRC-019 coordination.					

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017017732	MOD-025-2	R1	GenOn Northeast Management Company (GNMC)	NCR11137	7/1/2016	7/24/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On June 2, 2017, ReliabilityFirst determined that the entity, as a Generator Owner, was in noncompliance with MOD-025-2 R1 identified during a Compliance Audit conducted from May 8, 2017 through May 19, 2017. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The entity did not perform the Real Power verifications by staged test as required for the first verification. The entity incorrectly performed the verifications using historical operational data. MOD-025-2 R1.1 requires that the first verification be performed via a staged test. As a result, the entity had verified none of its generating Facilities by July 1, 2016, thereby missing the 40% requirement detailed in the implementation plan for MOD-025-2 R1. Additionally, the entity did not submit the data using the MOD-025-2 Attachment 2 (or a similar form containing the same information). Instead, the entity submitted the data using the PJM (Transmission Planner) processes that were in place at the time—the entity submitted data via eGads, email, etc. which did not include all information that is required by MOD-025-2. The entity also submitted these forms late (i.e. after the 90 day deadline in MOD-025-2 R1.2). The entity did provide some data to PJM. The data the entity provided, however, did not meet the MOD-025 requirements. The entity provided the test data that PJM requested using a PJM form, but what PJM requests is different than what MOD-025-2 requires. The PJM forms were very similar to, but not as inclusive as, MOD-025 Attachment 2, which required more data. This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to develop and implement an effective plan to become compliant with MOD-025-2 R1 as of the July 1, 2016 implementation date. One root cause was that entity staff was ineffectively trained on how to comply with MOD-025-2 R1. That ineffective training led NRG to perform MOD-025-2 testing incorrectly (failing to perform the first verification using a staged test) by relying on what PJM required for its own purposes rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all contributing causes of this noncompliance. The entity contributes approximately 3,896 MW to the grid and operated at approximately a 65% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R1 and ended on July 24, 2017, when the entity completed its Mitigation Plan.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity performed and submitted to its Transmission Planner (PJM) some of the MOD-025 required testing elements before the initial enforcement date of July 1, 2016. (The entity performed the verification using historical data rather than via staged verifications. Had the entity performed the verifications via a staged verification, the results would have likely been identical.) The information that the entity failed to provide was not required or needed to validate net capability for the Transmission Planner. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) prescheduled and conducted Real Power verification testing in accordance with MOD-025 R1 at Keystone and Conemaugh Generating Facilities; 2) completed MOD-025 Attachment 2 and submitted it to PJM within 90 days in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability; and 3) developed and implemented an internal process for review of MOD-025 test information and submission of dates. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018634	MOD-025-2	R1	GenOn REMA 1 (GR1)	NCR11141	7/1/2016	10/23/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 6, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The entity is implementing NRG's corporate plan for demonstrating compliance with MOD-025 over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of applicable units to have performed Generator real power and reactive power verification testing by July 1, 2016 and 60% of applicable units to have performed generator real power and reactive power verification testing by July 1, 2017. As of the July 1, 2016 compliance date, the entity had performed real power testing and submitted data for 8 of the 10 units. The entity submitted these tests using the PJM Test form. The testing the entity performed was invalid because the entity performed the testing using the PJM Test form which did not include all of the data fields per MOD-025 Attachment 2. Therefore, none of the ten units in the entity registration met the 2016 reactive testing deadline. The entity met the July 1, 2017 compliance date requirements of 60% by correctly completing the MOD-025 real and reactive power verification for 9 of its 10 units. NRG incorrectly implemented a compliance plan in early 2015 that included the entity units within NRG's "fleet-wide" compliance approach that combined NRG registrations within the ReliabilityFirst footprint for a single compliance measurement. This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to come up with an effective plan to become compliant with MOD-025-2 R1 as of the July 1, 2016 implementation date. One reason why they failed to come up with an effective plan is that entity staff were ineffectively trained on how to show compliance with MOD-025-2 R1. That ineffective training led NRG to perform MOD-025-2 testing incorrectly by relying on what PJM required rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 (by conducting its testing in accordance with only PJM's requirements) would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all root causes of this noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R1 and ended on October 23, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity has historically been performing real and reactive power capability testing that closely matches the requirements in MOD-025-2. (The entity adheres to PJM Manual 14 D Rev 40 1/1/17 Attachment E. 2 -E3 Requirements and PJM Manual 21 Rev 12 1/1/17 Section 2.1-2.3 and Appendix A where reactive testing for these units is performed every 66 months. Net real power capability tests are also performed annually.) The entity has regularly verified real and reactive power testing and reported and communicated those results to its Transmission Planner. Lastly, the entity contributes approximately 662 MW to the grid and operated at approximately a 1% capacity factor during the noncompliance. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted the NRG corporate project approach to perform targeted testing on the entity registration to meet the 2007-09 Generator Verification Implementation Plan for MOD-025 R1; 2) ensured all required testing was performed by prescheduling units and completing verifications for the applicable units to meet the phased-in implementation requirements per MOD-025-2 Requirement 1 and 2; 3) completed MOD-025 Attachment 2 and submitted it to PJM in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability; 4) corrected MOD-025 Attachment 2 documentation and submitted for previous valid tests; and 5) developed and implemented a process for the internal review of test data by NRG's Regulatory Compliance and Commercial Operations teams prior to submittal to PJM to ensure all required data had been collected. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018635	MOD-025-2	R2	GenOn REMA 1 (GR1)	NCR11141	7/1/2016	10/23/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 6, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R2. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The entity is implementing NRG's corporate plan for demonstrating compliance with MOD-025 over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of applicable units to have performed Generator real power and reactive power verification testing by July 1, 2016 and 60% of applicable units to have performed generator real power and reactive power verification testing by July 1, 2017. As of the July 1, 2016 compliance date, the entity had performed real power testing and submitted data for 8 of the 10 units. The entity submitted these tests using the PJM Test form. The testing the entity performed was invalid because the PJM Test form did not include all of the data fields per MOD-025 Attachment 2. Therefore, none of the ten units in the entity registration met the 2016 reactive testing deadline. The entity met the July 1, 2017 compliance date requirements of 60% by correctly completing the real and reactive power verification for 9 of its 10 units. NRG incorrectly implemented a compliance plan in early 2015 that included the entity units within NRG's "fleet-wide" compliance approach that combined NRG registrations within the ReliabilityFirst footprint for a single compliance measurement. This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to come up with an effective plan to become compliant with MOD-025-2 R2 as of the July 1, 2016 implementation date. One reason why they failed to come up with an effective plan is that the entity staff were ineffectively trained on how to show compliance with MOD-025-2 R2. That ineffective training led NRG to perform MOD-025-2 testing incorrectly by relying on what PJM required rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 (by conducting its testing in accordance with only PJM's requirements) would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all root causes of this noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R2 and ended on October 23, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity has historically been performing real and reactive power capability testing that closely matches the requirements in MOD-025-2. (The entity adheres to PJM Manual 14 D Rev 40 1/1/17 Attachment E. 2 -E3 Requirements and PJM Manual 21 Rev 12 1/1/17 Section 2.1-2.3 and Appendix A where reactive testing for these units is performed every 66 months.) The entity has regularly verified real and reactive power testing and reported and communicated those results to its Transmission Planner. Lastly, the entity contributes approximately 662 MW to the grid and operated at approximately a 1% capacity factor during the noncompliance. No harm is known to have occurred. ReliabilityFirst considered the entity's MOD-025 R2 compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted the NRG corporate project approach to perform targeted testing on the entity registration to meet the 2007-09 Generator Verification Implementation Plan for MOD-025 R1; 2) ensured all required testing was performed by prescheduling units and completing verifications for the applicable units to meet the phased-in implementation requirements per MOD-025-2 Requirement 1 and 2; 3) completed MOD-025 Attachment 2 and submitted it to PJM in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability; 4) corrected MOD-025 Attachment 2 documentation and submitted for previous valid tests; and 5) developed and implemented a process for the internal review of test data by NRG's Regulatory Compliance and Commercial Operations teams prior to submittal to PJM to ensure all required data had been collected. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017017847	PRC-019-2	R1	GenOn Northeast Management Company (GNMC)	NCR11137	7/1/2016	2/28/2017	Compliance Audit	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On June 2, 2017, ReliabilityFirst determined that the entity, as a Generator Owner, was in noncompliance with PRC-019-2 R1 identified during a Compliance Audit conducted from May 8, 2017 through May 19, 2017. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. PRC-019-2 R1 is a phased in implementation Standard requiring the entity to perform analyses to verify voltage regulating controls and system protection coordination of at least 40% of its applicable units by July 1, 2016. During the May 2017 Compliance Audit of the entity, the Audit Team identified a noncompliance with PRC-019-2 R1. The entity failed to verify 40% of its generating Facilities by the required July 1, 2016 date. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of the PRC-019, PRC-024, MOD-025, MOD-026 and MOD-027 Reliability Standards, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-019. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-019-2 was correct. The entity contributes approximately 3,896 MW to the grid and operated at approximately a 65% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-019-2 R1 and ended on February 28, 2017, when the entity completed its Mitigation Plan.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is the discoordination of voltage control, which can result in a generator falsely tripping. The risk is minimized because when the entity performed the verification and coordination, no changes were required. There were no deficiencies in the coordination at any of the entity units. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 48% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity completed the required PRC-019 R1 analysis for units at the Generating facilities and is now executing its implementation plan consistent with NERC guidance concerning phased implementation on a registration basis and revised its processes and procedures accordingly. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018630	PRC-024-2	R1	GenOn Northeast Management Company (GNMC)	NCR11137	7/1/2016	2/28/2017	Self-Report	Completion

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of the entity's applicable units to have performed analyses to verify the generator Frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG self-reported that the entity did not complete its verification of 40% of its generating units by the July 1, 2016 implementation date. As of July 1, 2016, the entity had completed its verification on none of its units. As of the July 1, 2017 implementation date, however, the entity completed the required verification for 4 of 4 applicable units (100%). NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct. The entity contributes approximately 3,896 MW to the grid and operated at approximately a 65% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R1 and ended on February 28, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted NRG's fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC registration, including the O&M managed facilities, to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1 & R2; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and 2) completed the required analysis for the entity Facilities using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-024-2 Requirements 1 & 2. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018632	PRC-024-2	R1	GenOn Power Midwest (GPM)	NCR11136	7/1/2016	5/27/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 5, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of the entity's applicable units to have performed analyses to verify the generator Frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG self-reported that the entity did not complete its verification of 40% of its generating units by the July 1, 2016 implementation date. As of July 1, 2016, the entity had completed its verification on three of eight its units (38%). As of the July 1, 2017 implementation date, however, the entity had completed the required verification for seven of its eight applicable units (88%). NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct. The entity contributes approximately 1,837 MW to the grid and operated at approximately a 15% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R1 and ended on May 27, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. The risk is further reduced because the entity had completed its verification on 33% of its applicable units (instead of the required 40%) by the July 1, 2016 implementation date. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted NRG's fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC registration, including the O&M managed facilities, to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1 & R2; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and 2) completed the required analysis for the entity Facilities using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-024-2 Requirements 1 & 2. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018631	PRC-024-2	R2	GenOn Northeast Management Company (GNMC)	NCR11137	7/1/2016	2/28/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R2. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan, requires 40% of the entity's applicable units to have performed analyses to verify the generator Frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG self-reported that the entity did not complete its verification of 40% of its generating units by the July 1, 2016 implementation date. As of July 1, 2016, the entity had completed its verification on none of its applicable units. As of the July 1, 2017 implementation date, however, the entity had completed the required verification for all four of its applicable units. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct. The entity contributes approximately 3,896 MW to the grid and operated at approximately a 65% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R2 and ended on February 28, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted NRG's fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC registration, including the O&M managed facilities, to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1 & R2; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and 2) completed the required analysis for the entity Facilities using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-024-2 Requirements 1 & 2. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018633	PRC-024-2	R2	GenOn Power Midwest (GPM)	NCR11136	7/1/2016	5/27/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 5, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R2. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan, requires 40% of the entity's applicable units to have performed analyses to verify the generator frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG self-reported that the entity did not complete its verification of 40% of its generating units by the July 1, 2016 implementation date. As of July 1, 2016, the entity had completed its verification on three of its eight (33%) applicable units. As of the July 1, 2017 implementation date, however, the entity had completed the required verification on seven of its eight (88%) applicable units. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct. The entity contributes approximately 1,837 MW to the grid and operated at approximately a 15% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R2 and ended on May 27, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. The risk is further reduced because the entity had completed its verification on 33% of its applicable units (instead of the required 40%) by the July 1, 2016 implementation date. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted NRG's fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC registration, including the O&M managed facilities, to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1 & R2; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and 2) completed the required analysis for the entity Facilities using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-024-2 Requirements 1 & 2. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018763	MOD-025-2	R1	Homer City Generation, L.P. (Homer)	NCR11297	7/1/2016	10/3/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 1, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The entity is implementing NRG's corporate plan for demonstrating compliance with MOD-025 over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of applicable units to have performed Generator real power and reactive power verification testing by July 1, 2016 and 60% of applicable units to have performed generator real power and reactive power verification testing by July 1, 2017. As of the July 1, 2016 and July 1, 2017 compliance dates, the entity had tested and submitted data for only one of three units, completing the real power and reactive power verification for only 33% of its applicable units. NRG incorrectly implemented a compliance plan in early 2015 that included the entity units within NRG's "fleet-wide" compliance approach that combined NRG registrations within the ReliabilityFirst footprint for a single compliance measurement. This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to develop an effective plan to become compliant with MOD-025-2 R1 as of the July 1, 2016 implementation date. One reason for this failure is that entity staff was ineffectively trained on how to show compliance with MOD-025-2 R1. That ineffective training led NRG to perform MOD-025-2 testing incorrectly by relying on what PJM required rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 (by conducting its testing in accordance with only PJM's requirements) would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all root causes of this noncompliance. The entity contributes approximately 2,194 MW to the grid and operated at approximately a 55% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R1 and ended on October 3, 2017, when the entity completed its Mitigation Plan.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity has historically been performing real and reactive power capability testing that closely matches the requirements in MOD-025-2. (The entity adheres to PJM Manual 14 D Rev 40 1/1/17 Attachment E. 2 -E3 Requirements and PJM Manual 21 Rev 12 1/1/17 Section 2.1-2.3 and Appendix A where reactive testing for these units is performed every 66 months. Net real power capability tests are also performed annually.) The entity has regularly verified real and reactive power testing and reported and communicated those results to its Transmission Planner. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted the NRG Energy, Inc. corporate project approach to perform targeted testing on the entity Generation registration to meet the 2007-09 Generator Verification Implementation Plan for MOD-025 R1; 2) ensured all required testing was performed and NERC MOD-025 Attachment 2 was completed for each of the entity units to meet the phased-in implementation requirements per MOD-025-2 Requirement 1; 3) submitted NERC MOD-025 Attachment 2 to PJM in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability; and 4) developed and implemented a process for the internal review of test data by NRG's Regulatory Compliance and Commercial Operations teams prior to submittal to PJM to ensure all required data had been collected. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018765	MOD-025-2	R2	Homer City Generation, L.P. (Homer)	NCR11297	7/1/2016	9/8/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 1, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R2. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The entity is implementing NRG's corporate plan for demonstrating compliance with MOD-025 over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of applicable units to have performed Generator real power and reactive power verification testing by July 1, 2016 and 60% of applicable units to have performed generator real power and reactive power verification testing by July 1, 2017. As of the July 1, 2016 and July 1, 2017 compliance dates, the entity had tested and submitted data for only one of three units, completing the real power and reactive power verification for only 33% of its applicable units. NRG incorrectly implemented a compliance plan in early 2015 that included the entity units within NRG's "fleet-wide" compliance approach that combined NRG registrations within the ReliabilityFirst footprint for a single compliance measurement. This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to come up with an effective plan to become compliant with MOD-025-2 R2 as of the July 1, 2016 implementation date. One reason why they failed to come up with an effective plan is that entity staff were ineffectively trained on how to show compliance with MOD-025-2 R2. That ineffective training led NRG to perform MOD-025-2 testing incorrectly by relying on what PJM required rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 (by conducting its testing in accordance with only PJM's requirements) would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all root causes of this noncompliance. Lastly, the entity contributes approximately 2,194 MW to the grid and operated at approximately a 55% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R2 and ended on September 8, 2017, when the entity completed its Mitigation Plan.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity has historically been performing real and reactive power capability testing that closely matches the requirements in MOD-025-2. (The entity adheres to PJM Manual 14 D Rev 40 1/1/17 Attachment E. 2 -E3 Requirements and PJM Manual 21 Rev 12 1/1/17 Section 2.1-2.3 and Appendix A where reactive testing for these units is performed every 66 months. Net real power capability tests are also performed annually.) The entity has regularly verified real and reactive power testing and reported and communicated those results to its Transmission Planner. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted the NRG Energy, Inc. corporate project approach to perform targeted testing on the entity Generation registration to meet the 2007-09 Generator Verification Implementation Plan for MOD-025 R1; 2) ensured all required testing was performed and NERC MOD-025 Attachment 2 was completed for each of the four reactive test verifications for each of the entity units to meet the phased-in implementation requirements per MOD-025-2 Requirement 2; 3) submitted NERC MOD-025 Attachment 2 to PJM in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability; and 4) developed and implemented a process for the internal review of test data by NRG's Regulatory Compliance and Commercial Operations teams prior to submittal to PJM to ensure all required data had been collected. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018766	PRC-019-2	R1	Homer City Generation, L.P. (Homer)	NCR11297	7/1/2016	4/30/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 1, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. PRC-019-2 R1 is a phased in implementation Standard requiring the entity to perform analyses to verify voltage regulating controls and system protection coordination of at least 40% of its applicable units by July 1, 2016. The entity failed to verify 40% of its generating Facilities by the required July 1, 2016 date. As of July 1, 2016, the entity had verified none of its units. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of the PRC-019, PRC-024, MOD-025, MOD-026 and MOD-027 Reliability Standards, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-019. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-019-2 was correct. Lastly, the entity contributes approximately 2,194 MW to the grid and operated at approximately a 55% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-019-2 R1 and ended on April 30, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 48% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted the corporate project approach to perform targeted coordination analyses of applicable NRG Energy, Inc. units by NERC Registered Entity to meet the 2007-09 Generator Verification Implementation Plan for PRC-019-2 R1; and 2) completed the required coordination analyses for the entity units to meet the phased-in implementation requirements per PRC-019-2 Requirement 1. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018767	PRC-024-2	R1	Homer City Generation, L.P. (Homer)	NCR11297	7/1/2016	4/30/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 1, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of the entity's applicable units to have performed analyses to verify the generator Frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG self-reported that the entity did not complete its verification of 40% of its generating units by the July 1, 2016 implementation date. As of July 1, 2016, the entity had completed its verification on none of its units. As of the July 1, 2017 implementation date, however, the entity had completed the required verification for all three of its units. The entity completed the verifications on April 30, 2017. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct. Lastly, the entity contributes approximately 2,194 MW to the grid and operated at approximately a 55% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R1 and ended on April 30, 2017, when the entity completed its Mitigation Plan.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted its corporate project approach to perform targeted coordination analyses of applicable NRG units by NERC Registered Entity to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1; and 2) completed the required coordination analyses for the entity units to meet the phased-in implementation requirements per PRC-024-2 Requirement 1. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018842	PRC-024-2	R2	Homer City Generation, L.P. (Homer)	NCR11297	7/1/2016	4/30/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 6, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R2. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan, requires 40% of the entity's applicable units to have performed analyses to verify the generator frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG self-reported that the entity did not complete its verification of 40% of its generating units by the July 1, 2016 implementation date. As of July 1, 2016, the entity had completed its verification on none of its units. As of the July 1, 2017 implementation date, however, the entity had completed the required verification for all three of its units. The entity completed the verifications on April 30, 2017. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct. Lastly, the entity contributes approximately 2,194 MW to the grid and operated at approximately a 55% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R2 and ended on April 30, 2017, when the entity completed its Mitigation Plan.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, no changes to the existing relay settings were required. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted its corporate project approach to perform targeted coordination analyses of applicable NRG units by NERC Registered Entity to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R2; and 2) completed the required coordination analyses for the entity units to meet the phased-in implementation requirements per PRC-024-2 Requirement 2. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018019843	PRC-019-2	R1	Indianapolis Power & Light Company (IPL)	NCR00798	7/1/2016	8/30/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On June 5, 2018, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2 R1. During an internal program review, the entity discovered that, due to a lack of effective processes and procedures to track the work, it failed to coordinate the voltage regulating system controls for its generation facilities by the required deadline. Subsequently, the entity completed the study and coordination of 100% of its generation facilities by August 30, 2017. The root cause of this noncompliance was the entity's lack of effective processes and procedures to track the work. This major contributing factor involves the management practice of reliability quality management, which includes maintaining a system for identifying and deploying internal controls. This noncompliance started on July 1, 2016, the first implementation deadline that the entity missed and ended on August 30, 2017, when the entity completed the coordination work.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by failing to coordinate voltage regulating system controls is that it could result in unnecessary tripping of a generator or damage to the equipment. This risk was mitigated in this case by the following factors. First, when the entity completed the study, it found that in all cases, the excitation system limiters always operated before the excitation system protection, which prevents an unnecessary disconnection of the generator. Second, the entity was only required to make minor adjustments to two gas turbine loss of field relays, which would not adversely affect the protection for the unit. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity completed the study and coordination of 80% of the entity's generating locations to meet the implementation date of July 1, 2018. As an additional mitigating action, the entity implemented an automated tracking tool that provides reminders for upcoming required activities to multiple responsible people and their supervisors. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018639	MOD-025-2	R1	NRG East	NCR11715	7/1/2016	10/11/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The entity is implementing NRG's corporate plan for demonstrating compliance with MOD-025 over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of applicable units to have performed Generator real power and reactive power verification testing by July 1, 2016 and 60% of applicable units to have performed generator real power and reactive power verification testing by July 1, 2017. The entity registration, however, was reorganized on December 16, 2016. Before December 16, 2016, the registration was comprised of several legacy NRG Registered Entities (legacy Registered Entities), which were de-activated simultaneously with the reorganization of the entity registration. NRG incorrectly implemented a compliance plan in early 2015 that included the entity units within NRG's "fleet-wide" compliance approach that combined NRG registrations within the ReliabilityFirst footprint for a single compliance measurement. As of the July 1, 2016 implementation date, the legacy Registered Entities under the entity had not verified 40% of its applicable units. At that time, only a total of 11 units (20% of applicable units) had been properly tested with adequate documentation and submittals. This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to come up with an effective plan to become compliant with MOD-025-2 R1 as of the July 1, 2016 implementation date. One reason why they failed to come up with an effective plan is that the entity staff was ineffectively trained on how to show compliance with MOD-025-2 R1. That ineffective training led NRG to perform MOD-025-2 testing incorrectly by relying on what PJM required rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 (by conducting its testing in accordance with only PJM's requirements) would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all root causes of this noncompliance. The entity contributes approximately 7,529 MW to the grid and operated at approximately a 9% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R1 and ended on October 11, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity has historically been performing real and reactive power capability testing that closely matches the requirements in MOD-025-2. (The entity adheres to PJM Manual 14 D Rev 40 1/1/17 Attachment E. 2 -E3 Requirements and PJM Manual 21 Rev 12 1/1/17 Section 2.1-2.3 and Appendix A where reactive testing for these units is performed every 66 months. Net real power capability tests are also performed annually.) The entity has regularly verified real and reactive power testing and reported and communicated those results to its Transmission Planner. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted the NRG corporate project approach to perform targeted testing on the entity registration to meet the 2007-09 Generator Verification Implementation Plan for MOD-025 R1; 2) ensured all required testing was performed by prescheduling units and completing verifications for the applicable units to meet the phased-in implementation requirements per MOD-025-2 Requirement 1 and 2; 3) completed MOD-025 Attachment 2 and submitted it to PJM in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability; 4) corrected MOD-025 Attachment 2 documentation and submitted for previous valid tests; and 5) developed and implemented a process for the internal review of test data by NRG's Regulatory Compliance and Commercial Operations teams prior to submittal to PJM to ensure all required data had been collected. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018640	MOD-025-2	R2	NRG East	NCR11715	7/1/2016	10/11/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with MOD-025-2 R2. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The entity is implementing NRG's corporate plan for demonstrating compliance with MOD-025 over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of applicable units to have performed Generator real power and reactive power verification testing by July 1, 2016 and 60% of applicable units to have performed generator real power and reactive power verification testing by July 1, 2017. The entity registration, however, was reorganized on December 16, 2016. Before December 16, 2016, the registration was comprised of several legacy NRG Registered Entities (legacy Registered Entities), which were de-activated simultaneously with the reorganization of the entity registration. As of the July 1, 2016 implementation date, the legacy Registered Entities under the entity had not verified 40% of its applicable units. At that time, only a total of 11 units (20% of applicable units) had been properly tested with adequate documentation and submittals. NRG incorrectly implemented a compliance plan in early 2015 that included the entity units within NRG's "fleet-wide" compliance approach that combined NRG registrations within the ReliabilityFirst footprint for a single compliance measurement. That incorrect interpretation and implementation led to this noncompliance. This noncompliance involves the management practices of planning, workforce management, and verification. NRG (and the entity) failed to come up with an effective plan to become compliant with MOD-025-2 R2 as of the July 1, 2016 implementation date. One reason why they failed to come up with an effective plan is that entity staff were ineffectively trained on how to show compliance with MOD-025-2 R2. That ineffective training led NRG to perform MOD-025-2 testing incorrectly by relying on what PJM required rather than what MOD-025-2 required. Verification is also involved because NRG failed to verify that its strategy for achieving compliance with MOD-025-2 (by conducting its testing in accordance with only PJM's requirements) would actually achieve compliance. The failure to plan, the ineffective training, and the failure to verify are all root causes of this noncompliance. The entity contributes approximately 7,529 MW to the grid and operated at approximately a 9% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with MOD-025-2 R2 and ended on October 11, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that by providing incorrect data regarding generating capacity, the veracity of generating models and power flow analyses for planning and operations would be affected. The risk is minimized because the entity has historically been performing real and reactive power capability testing that closely matches the requirements in MOD-025-2. (The entity adheres to PJM Manual 14 D Rev 40 1/1/17 Attachment E. 2 -E3 Requirements and PJM Manual 21 Rev 12 1/1/17 Section 2.1-2.3 and Appendix A where reactive testing for these units is performed every 66 months. Net real power capability tests are also performed annually.) The entity has regularly verified real and reactive power testing and reported and communicated those results to its Transmission Planner. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted the NRG corporate project approach to perform targeted testing on the entity registration to meet the 2007-09 Generator Verification Implementation Plan for MOD-025 R1; 2) ensured all required testing was performed by prescheduling units and completing verifications for the applicable units to meet the phased-in implementation requirements per MOD-025-2 Requirement 1 and 2; 3) completed MOD-025 Attachment 2 and submitted it to PJM in accordance with PJM Compliance Bulletin CB023 NERC Standard MOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability; 4) corrected MOD-025 Attachment 2 documentation and submitted for previous valid tests; and 5) developed and implemented a process for the internal review of test data by NRG's Regulatory Compliance and Commercial Operations teams prior to submittal to PJM to ensure all required data had been collected. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018636	PRC-019-2	R1	NRG East	NCR11715	7/1/2016	6/30/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-019-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. PRC-019-2 R1 is a phased in implementation Standard requiring the entity to perform analyses to verify voltage regulating controls and system protection coordination of at least 40% of its applicable units by July 1, 2016. The entity registration, however, was reorganized on December 16, 2016. Before December 16, 2016, the registration was comprised of several legacy NRG Registered Entities (legacy Registered Entities), which were de-activated simultaneously with the reorganization of the entity registration. As of the implementation plans' July 1, 2017 milestone, the entity, completed the required analyses for 47 of the 55 applicable units (85%). However, the entity self-reported that the legacy Registered Entities did not verify 40% of their generating facilities by July 1, 2016, per PRC-019-2 R1. Specifically, three legacy Registered Entities did not complete the required analyses to meet the required percentages for these individual legacy registrations. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of the PRC-019, PRC-024, MOD-025, MOD-026 and MOD-027 Reliability Standards, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-019. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-019-2 was correct. The entity contributes approximately 7,529 MW to the grid and operated at approximately a 9% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-019-2 R1 and ended on June 30, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is the discoordination of voltage control, which can result in a generator falsely tripping. The risk is minimized because when the entity performed the verification and coordination, only a few changes to a small set of units in the NRG East fleet (specifically baseload units) were needed to be applied to the existing relay settings and excitation controls. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 48% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted the fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC Registered Entity to meet the 2007-09 Generator Verification Implementation Plan for PRC-019-2 R1; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and 2) completed the required analysis for the entity units using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-019-2 Requirement 1. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018637	PRC-024-2	R1	NRG East	NCR11715	7/1/2016	6/30/2017	Self-Report	Completion

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R1. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan requires 40% of the entity's applicable units to have performed analyses to verify the generator Frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016. The entity registration, however, was reorganized on December 16, 2016. Before December 16, 2016, the registration was comprised of several legacy NRG Registered Entities (legacy Registered Entities), which were de-activated simultaneously with the reorganization of the entity registration. As of the implementation plans' July 1, 2017 milestone, the entity, completed the required analyses for 53 of the 55 applicable units (96%). However, the entity self-reported that the legacy Registered Entities did not verify 40% of their generating facilities by July 1, 2016, per PRC-024-2 R1. The entity only verified five of its 23 generating units (22%) within the legacy entity registration by July 1, 2016 as required by PRC-024-2 R1. The entity's failure to verify 40% of its generating units by its registration date of December 16, 2016 is a cause of this noncompliance. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. The entity contributes approximately 7,529 MW to the grid and operated at approximately a 9% capacity factor during the noncompliance. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R1 and ended on June 30, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, only a few changes to a small set of units in the NRG East fleet (specifically baseload units) were needed to be applied to the existing relay settings. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted the fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC registration, including the O&M managed facilities, to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1 & R2; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and 2) completed the required analysis for the entity Facilities using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-024-2 Requirements 1 & 2. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018638	PRC-024-2	R2	NRG East	NCR11715	7/1/2016	6/30/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 3, 2017, the entity submitted a Self-Report stating that, as a Generator Owner, it was in noncompliance with PRC-024-2 R2. NRG is the parent company of the entity and owns and operates the entity. NRG directs NERC compliance activities for the entity from the corporate level. The PRC-024-2 Reliability Standard is being implemented over a five year term beginning July 1, 2014. The Standard's implementation plan, requires 40% of the entity's applicable units to have performed analyses to verify the generator Frequency and generator voltage protective relaying settings do not trip the applicable unit within the "no trip zone" of PRC-024 Attachments 1 and 2 by July 1, 2016. The entity registration, however, was reorganized on December 16, 2016. Before December 16, 2016, the registration was comprised of several legacy NRG Registered Entities (legacy Registered Entities), which were de-activated simultaneously with the reorganization of the entity registration. As of the implementation plans' July 1, 2017 milestone, the entity, completed the required analyses for 53 of the 55 applicable units (96%). However, the entity self-reported that the legacy Registered Entities did not verify 40% of their generating facilities by July 1, 2016, per PRC-024-2 R1. The entity only verified five of its 23 generating units (22%) within the legacy registration by July 1, 2016 as required by PRC-024-2 R1. The entity's failure to verify 40% of its generating units by its registration date of December 16, 2016 is the root of this noncompliance. NRG owns, operates and maintains a large generating fleet (including the entity) and owns transmission facilities, with a presence in all eight NERC regions. In addition, NRG operates power plants under O&M agreements for third parties (contract generation). In order to effectively and efficiently meet the compliance requirements of PRC-024-2, NRG incorrectly applied the implementation phase-in percentage for each Standard to the total number of applicable NRG facilities for its combined Registered Entities, within each Interconnection (East, West, and ERCOT) for PRC-024-2. NRG should have applied the implementation phase-in percentage for each Standard to the total number of units per Registered Entity. NRG misinterpreted what the Standard required and that misinterpretation is a root cause of this noncompliance. That misinterpretation also involves the management practice of verification as NRG did not verify that its understanding of the implementation requirements for PRC-024-2 was correct. The entity contributes approximately 7,529 MW to the grid and operated at approximately a 9% capacity factor during the noncompliance. This noncompliance started on July 1, 2016, when the entity was required to comply with PRC-024-2 R2 and ended on June 30, 2017, when the entity completed its Mitigating Activities.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by this instance of noncompliance is that if the frequency relays are set in the "no trip zone," a generator could trip incorrectly for a system event, and thereby cause a loss of generation. The risk is minimized because when the entity performed the verification study, only a few changes to a small set of units in the NRG East fleet (specifically baseload units) were needed to be applied to the existing relay settings. ReliabilityFirst notes that using the incorrect NRG methodology described above, NRG achieved an Eastern Interconnection compliance level of 44% as of July 1, 2016. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this issue, the entity: 1) adjusted the fleet-wide implementation plan to perform targeted analyses of applicable NRG units by NERC registration, including the O&M managed facilities, to meet the 2007-09 Generator Verification Implementation Plan for PRC-024 R1 & R2; 60% compliant by July 1, 2017, 80% compliant by July 1, 2018, and 100% compliant by July 1, 2019; and 2) completed the required analysis for the entity Facilities using the revised NRG implementation plan to meet the phased-in implementation requirements per PRC-024-2 Requirements 1 & 2. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020083	PRC-005-6	R3	Wisconsin Electric Power Company (WEPCO)	NCR00951	11/1/2016	9/12/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On July 13, 2018 and on October 26, 2018, the entity submitted Self-Reports stating that, as a Distribution Provider and Generator Owner, it was in noncompliance with PRC-005-6 R3. ReliabilityFirst consolidated the second Self-Report into the first Self-Report because the second was discovered while the entity completed mitigating activities for the first Self-Report. In May 2018, while preparing for the entity's upcoming 2019 NERC audit, the entity undertook a review of its last three years of PRC-005-6 battery activities. In this review, the entity discovered that a 2016 maintenance activity for two 125-volt station batteries was not completed within the maximum interval of 18 months. More specifically, the two battery bank's annual tests were not reviewed against the battery baseline for a period of 25 and 28 months, respectively. The entity, however, did perform annual and quarterly testing on the battery banks during the period of noncompliance that indicated the batteries were functioning properly. (The entity had established a practice of performing the 18 month maintenance activities on the NERC batteries on an annual basis. The baseline review for these batteries was completed in 2015 and 2017, but was not completed in 2016.) As a result of subsequent review and discussion with its Transmission Operator (TOP), American Transmission Company (ATC), the entity determined that 11 additional battery banks, which supply control power to ATC Bulk Electric System breakers, were also not reviewed within the maximum interval of 18 months; making a total of 13 battery banks that were not timely reviewed. At the affected substations that had battery banks that were not timely reviewed, the 125VDC batteries provide trip and close control power to ATC's 138kV breakers. None of the substations or associated battery banks support or rely on Remedial Actions Schemes (RAS). Two of these substations are on Blackstart Resource Unit cranking paths. The entity had established a practice of performing the 18-month maintenance activities for all of its NERC batteries and battery banks (including the 13 at issue in this noncompliance) on an annual basis. However, the entity failed to complete the review for all 13 of these battery banks at different times in 2016 and 2017. Regarding the root cause, when the entity tests a battery or a battery bank on its annual schedule, the results are manually uploaded into the entity's Cascade system (a tracking database), and an automatic notification is sent to a prescribed list of individuals to review this test result. The engineer is then responsible to review the results against the baseline results, document their review, identify any anomalies, and then close out the work order in Cascade to complete this activity. These noncompliances involve the management practices of work management and workforce management. The alert emails were sent to the appropriate individuals, but the Cascade work orders issued for these activities were not completed within the prescribed interval of 18 calendar months. The work orders were not completed due to ineffective work management as the current work process had no additional automated tracking or follow-up notification to the engineer to complete the review of the work orders within the compliance interval. That ineffective work management design (lacking a follow-up and automated tracking) is a root cause of this noncompliance. Workforce management through ineffective training is also a contributing cause as the individuals responsible for completing the work orders were not effectively trained on the importance of timely completing the work orders. This noncompliance started on November 1, 2016, when the entity missed the 18 month maintenance interval on the first battery bank and ended on September 12, 2018, when the entity completed the overdue maintenance activities on all of the relevant battery banks.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by these noncompliances is that unmaintained and untested battery banks could fail and that failure could lead to local loss of load or transmission equipment at the substation. The risk is minimized because during the noncompliance, the entity successfully performed quarterly inspections and those inspections revealed no performance issues with the battery banks. The entity also monitors the battery chargers that normally carry the station DC load and the voltage on battery banks that provide backup power remotely. That monitoring revealed no significant conditions with the battery banks. Lastly, when the entity performed the overdue tests, the tests revealed that the battery banks were functioning properly. No harm is known to have occurred. The entity has relevant compliance history. However, ReliabilityFirst determined that the entity's compliance history should not serve as a basis for applying a penalty because the prior noncompliance was an isolated issue that was promptly identified, assessed, and corrected and both the prior noncompliance and the current noncompliances were promptly self-reported and mitigated. The prior noncompliance and the current noncompliances also have different root causes, which further makes the prior noncompliance distinguishable.
Mitigation	To mitigate this noncompliance, the entity: 1) created an Engineering Review tracking report that identifies all reviews required for NERC batteries. The report identifies the non-compliance date for the review (18 months from previous review) and the key milestone dates to manage responsible parties to stay within compliance. This is to be reviewed on a monthly basis; 2) created a monthly control activity in the entity's FERC Compliance Database to review the Engineering Review completion status; and

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2018020083	PRC-005-6	R3	Wisconsin Electric Power Company (WEPCO)	NCR00951	11/1/2016	9/12/2018	Self-Report	Completed
			3) developed a training module to explain the compliance tasks required for VLA and VRLA batteries, including the roles and responsibilities of all stakeholders from field personnel through program administrators. ReliabilityFirst has verified the completion of all mitigation activity.					

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
FRCC2018020722	PRC-006-2	R9.	Beaches Energy Services of Jacksonville Beach (“the Entity”)	NCR00004	2/9/2016	11/16/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 21, 2018, the Entity submitted a Self-Report stating that, as a Distribution Provider and Transmission Owner, it was in noncompliance with PRC-006-2 R9. This noncompliance started on February 9, 2016, when the Entity failed to properly set the time delay of their Under-Frequency Load Shedding (UFLS) relays to provide automatic tripping of Load in accordance with the UFLS program as determined by its Planning Coordinator (PC), and ended on November 16, 2018, when BES adjusted the time delay for the UFLS relays to meet the Planning Coordinator parameters. Specifically, the Entity's relay test records indicate that 12 of the Entity's 15 UFLS relays had a total time delay greater than 0.28 seconds and were outside of tripping parameter limits as required by PRC-006 R9 and the limits set by the FRCC UFLS program of less than 0.28 seconds (where the total time delay = intentional delay + relay delay + breaker delay). The cause for this noncompliance was insufficient training on the FRCC UFLS program and the associated settings.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk was reduced because if a UFLS event had occurred, the Entity's UFLS relays would have operated; however, the operation would have been slower than required. The maximum time delay would have been .07 seconds greater than the .28 seconds specified by the FRCC UFLS program. There were no UFLS events during the period of noncompliance. The Entity's UFLS Load Shed represents 0.51% of the Regional UFLS Load Shed. No harm is known to have occurred. The Region determined that the Entity’s compliance history should not serve as a basis for applying a penalty.
Mitigation	To mitigate this noncompliance, the Entity: 1) performed an extent of condition review; 2) performed a root cause analysis; 3) corrected the settings on the UFLS relays to be within the allowable range of the FRCC UFLS Regional Program; 4) tested to confirm the correct settings were entered; 5) created workflow with three levels of review and approval to ensure the devices have the correct settings; and 6) created an annual training program for all BES employees involved with the UFLS program which will be provided by an outside entity based on the FRCC UFLS program.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
NPCC2018020744	PRC-005-6	R3	National Grid USA	NCR11171	9/1/2017	04/02/2018	Self-Log	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a “noncompliance,” regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On November 29, 2018, National Grid USA ("the Entity") submitted a Self-Log stating that, as a Transmission Owner (TO), it was in noncompliance with PRC-005-6 R3. The Entity discovered that it had failed to perform certain diagnostic tests on one battery bank, of the type Vented Lead Acid (VLA), at one of its 345kV substations. The battery bank had been last tested on February 16, 2016. Therefore, per the time-based maximum interval of eighteen calendar months, as specified in PRC-005-6 Table 1-4(a), maintenance on this device was required by August 31, 2017. This noncompliance started on September 1, 2017, the day after the date when the periodic maintenance for the battery bank was required by, and ended on April 2, 2018, when the Entity completed required diagnostic tests for a new VLA battery bank that it had installed to replace the existing aging unit. The root cause of this instance of noncompliance was that the diagnostic test Work Orders for the VLA batteries had been inadvertently, and prematurely, closed out in Cascade by the Substation Supervisor on January 30th, 2017 before verifying whether any actual testing work had been performed.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Lack of proper DC voltage at a substation could cause protection systems to misoperate or not operate when called upon. However, the substation at issue is equipped with a redundant battery bank (fully tested in accordance with required intervals) that operates the primary protection system. Additionally, the non-compliant battery bank, which operates the substation's back-up protection system, was subject to bi-monthly Visual and Operational Inspections and was found to be in good working order from the time the required diagnostic tests were missed until the Entity replaced it with a new VLA bank. The Entity's Reliability Coordinator (the NYISO) carries required summer Operating Reserve of approximately 1965 MW and could have compensated for the loss of transmission facilities caused by a potential misoperation of the substation protection system by appropriately dispatching generating facilities in its Control Area. No harm is known to have occurred as a result of this noncompliance.
Mitigation	To mitigate this noncompliance, the Entity: 1) completed required diagnostic tests for a new VLA battery bank that was installed to replace the existing aging unit; 2) evaluated the incident with its Substation Operations/Maintenance & Construction (M&C) personnel and provided detailed information to responsible staff located throughout its facilities regarding the reasons that led to the noncompliance as well as detailed instructions that must be followed to ensure the timely completion of future maintenance items; and 3) enhanced its existing compliance software tool ("Cascade") by adding a “Work Completed Date” field that needs to be populated before any work order can be closed.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2017017523	PRC-004-4(i)	R3	Los Vientos Windpower III, LLC (LVWPIII)	NCR11538	1/30/2017	2/26/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On May 4, 2017, LVWPIII submitted a Self-Report stating that, as a Generator Owner (GO), it was in noncompliance with PRC-004-4(i) R3. Specifically, LVWPIII failed to identify whether its Protection System component caused a Misoperation within the later of 60 calendar days of notification or 120 calendar days of the Bulk Electric System (BES) interrupting device operation. While conducting a review of its Protection Systems operation reporting, LVWPIII discovered that it received notice of an interrupting device operation by a shared Composite Protection System on November 2, 2016. LVWPIII identified that its Protection System component did not cause a misoperation, but did not complete this analysis until February 26, 2017, 27 calendar days after the PRC-004-4(i) R3 deadline. The root cause of this noncompliance was that LVWPIII had an inadequate process to ensure compliance with all newly applicable NERC Reliability Standards. In particular, LVWPIII did not have a written process to evaluate and implement changes in compliance obligations for new or revised NERC Reliability Standards. As a result, LVWPIII personnel utilized an outdated procedure that did not contain the requirements and deadlines for the current version of PRC-004. This noncompliance started on January 30, 2017, the day after the identification was due, and ended on February 26, 2017, when LVWPIII determined that its Protection System component did not cause a Misoperation.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. First, while not timely, LVWPIII did provide evidence that it performed an analysis of the device operation at issue. Second, after conducting an analysis, LVWPIII did not identify any Protection System component Misoperation for this issue. Third, the other Composite Protection System owner indicated that it was aware of the interrupting device operation. Fourth, the duration of the noncompliance was relatively short, lasting less than one month. No harm is known to have occurred. Texas RE considered LVWPIII's and its affiliates' compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, LVWPIII: 1) completed the required PRC-004-4(i) R3 misoperation determination; 2) developed an email alert for BES interrupting device operation by a Composite Protection System. The email alert directs operators to archive evidence needed for PRC-004 evaluation and reporting, and to forward evidence to the responsible analysis personnel; 3) updated its PRC-004 compliance process document and, as part of an annual review of NERC compliance procedures, implemented an automated task to review the process document; 4) conducted NERC training for site managers and technicians on the reporting process and the updated requirements of PRC-004; 5) implemented a process to track and implement compliance obligations for new or revised NERC Reliability Standards. Texas RE verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
TRE2018019448	PRC-005-6	R3	Rattlesnake Wind I LLC (RSWILLC)	NCR11547	12/1/2016	3/23/2017	Compliance Audit	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	During a Compliance Audit conducted from February 6, 2018 through February 8, 2018, Texas RE determined that RSWILLC, as a Generator Owner (GO), was in noncompliance with PRC-005-6 R3. Specifically, RSWILLC did not timely perform all 18-month maintenance activities for two Vented-Lead Acid (VLA) batteries as required by PRC-005-6, Table 1-4(a). On April 18, 2015, two VLA battery banks were installed and commission testing was conducted on May 10, 2015. As a result RSWILLC was required to complete the maintenance activities for the two VLA batteries, with a maximum maintenance interval of 18-calendar-months, by November 30, 2016. However, RSWILLC did not complete the testing for the two VLA batteries until March 23, 2017. The root cause of the noncompliance was that RSWILLC did not correctly determine the 18-calendar-month maintenance interval start date. RSWILLC mistakenly believed that the 18-calendar-month interval started from the Facility's commercial operation date rather than from the date testing was performed. Additionally, RSWILLC misinterpreted the Implementation Plan for PRC-005-6. This noncompliance started on December 1, 2016, the day after the 18-calendar-month maintenance activities were due for its VLA batteries. The noncompliance ended on March 23, 2017, when the required maintenance activities were performed.
Risk Assessment	This noncompliance posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). This risk posed by this issue is that the VLA batteries at issue would not function as intended. However, the risk posed by this issue is reduced by several factors. First, the VLA batteries at issue comprise only 2% (2/89) of the total Protection System devices in RSWILLC's PSMP. Second, RSWILLC did not identify any issues with the two VLA batteries when it performed the required 18-month testing. Third, RSWILLC regularly performed monthly maintenance on the two VLA batteries at issue, reducing the scope for missed testing. Finally, during the Compliance Audit it was determined that this issue was limited to only one type of device and that RSWILLC timely tested all other devices in the PSMP. No harm is known to have occurred. Texas RE considered RSWILLC's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, RSWILLC: 1) performed the required maintenance activities on the VLA batteries; 2) contracted with a vendor to provide compliance program services and monthly compliance training; 3) conducted trainings to specifically address the PRC-005-6 implementation plan; and 4) implemented a spreadsheet to track the maximum maintenance intervals for Protection System maintenance and confirm that RSWILLC correctly recorded the required PRC-005-6 maintenance intervals for Protection System devices. Texas RE has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2016016322	INT-006-4	1	CXA Sundevil Holdco, Inc. (GRMA)	NCR05169	7/5/2016	7/5/2016	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On October 5, 2016, GRMA submitted a Self-Report stating that, as a Balancing Authority (BA), it was in violation with INT-006-4 R1. Specifically, GRMA reported that on July 5, 2016 at 1:40 PM, its scheduling software automatically approved a downward modification to a Confirmed Interchange (CI) even though it was not capable of supporting the magnitude including ramping throughout the duration of the Arranged Interchange (AI). The request for the AI should have been denied or curtailed. The downward modification or curtailment resulted in an AI that was below the low operating limit of GRMA. At 1:50 PM, the modified CI resulted in an over generation condition in which the primary BA was producing more than the expected magnitude of Interchange and ramp because of the minimum generation levels at GRMA. The primary BA then directed GRMA to reconfigure its generation blocks to achieve the magnitude of the interchange. The interchange value remained constant into the next hour. In the absence of being directed off line, at 2:56 PM, the output of GRMA matched the magnitude of the AI. After reviewing all relevant information, WECC determined that GRMA failed to deny an AI or curtail CI for which it did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the AI, as required by INT-006-4 R1, R1.1. The root cause of the violation was a lack of controls around the protocol and configuration of GRMA's electronic tagging system, which automatically accepted an AI, even though GRMA could not support the magnitude of the Interchange.
Risk Assessment	WECC determined that this noncompliance posed a minimal risk and did not pose a serious and substantial risk to the reliability of the BPS. In this instance, GRMA failed to deny an AI or curtail CI for which it did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the AI as required by INT-006-4 R1, R1.1. Such failure could result in inadvertent energy, an out-of-balance condition on the system, and incorrect NSI information to the Interconnection and BAAL deviations which affected another Requirement. The amount of over-generation relative to the Western Interconnection was small, ACE + 100 MW, during the event. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as negligible. However, this over-frequency (outside of BAAL limits) lasted a total of 66 minutes and GRMA was in communication with its RC during the entire event. Based on this, WECC determined that there was a low likelihood of causing negligible harm to the BPS. No harm is known to have occurred.
Mitigation	To mitigate this issue, GRMA: a. performed an investigation of the BAAL exceedance issue and provided a summary of the event to appropriate parties; b. conducted a conference call with the member BA, power marketer to review timeline of events associated with the issue and discuss future mitigation; c. developed procedures identifying coordination in the Day Ahead and Real-Time time frames and shared with the appropriate parties; d. created communication guidelines for shut-down to identify the conditions for a shut-down as well as the appropriate communications between parties for a shut-down; e. developed lessons learned training; and f. delivered training to GRMA system operators based on the procedures and communications guidelines developed.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017016778	MOD-025-2	1	USACE - Portland District	NCR05538	7/1/2016	6/30/2017	Self-report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	UNWP discovered on January 11, 2017 that it failed to provide its Transmission Planner verification of Real Power and Reactive Power in accordance with the requirements of Attachment 1 of MOD-025-2 R1. UNWP had 68 hydro-generating units applicable to this standard and requirements that it failed to verify its Real Power capabilities of at least 40% of as it assumed the incorrect effective date of the Standard. UNWP misunderstood the one-hour soak requirement for maximum Real Power capacities as required by Attachment 1, section 2.1.1. Because of this oversight, UNWP was unable schedule testing in accordance with the effective date of the Standard. The root cause of the issue was UNWP's misunderstanding of the testing specifications for the Requirement. Specifically, UNWP overlooked the one-hour soak time of the maximum Real Power and lagging Reactive Power capacity as required in Attachment 1 section 2.1.1. Subsequently, the testing was not scheduled in accordance with the accurate implementation schedule.
Risk Assessment	These issues posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, UNWP failed to provide its Transmission Planner verification of Real Power and Reactive Power in accordance with the requirements of Attachment 1 of MOD-025-2 R1. Such failures could potentially result in inaccurate information of generator gross and net Real Power capabilities used in planning models which are used to assess BES Reliability. Inaccurate information would result in inaccurate models; therefore, the BES could be planned with the expectation that a generator has the capability to mitigate a modeled system contingency, whereas it may not completely mitigate the contingency. UNWP owns and/or operates 68 applicable units location at eight facilities with a total capacity of 6,378 MW, of which 36 units were applicable to these issues. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as minor. However, UNWP implemented the WECC Generating Unit Model Validation testing for all its generating units in the past; therefore, if a real-time contingency that required the generating unit to respond were to occur, the current data would be satisfactory for mitigating the contingency. Additionally, the information obtained through the verification process is merely used for system modeling to develop contingencies and operating limits and not depended upon for real-time operating limits. Based on this, WECC determined that there was a moderate likelihood of causing minor harm to the BPS. No harm is known to have occurred.
Mitigation	To mitigate these issues, UNWP: a. developed a procedure to perform the required testing of MOD-025-2 R1 and 2; b. coordinated with all 8 facilities' Maintenance and Operation departments to determine when each Facilities testing could be performed; c. completed testing on 43% of applicable units; d. completed testing on 54% of applicable units; e. complete the testing on 57% of applicable units; f. completed testing on 72% of applicable units; g. completed testing on 93% of applicable units; and h. four generating units are out of commission for long term service and are unable to be tested. Testing will be complete once these units are ready for commercial service.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017016779	MOD-025-2	2	USACE - Portland District	NCR05538	7/1/2016	6/30/2017	Self-report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	UNWP discovered on January 11, 2017 that it failed to provide its Transmission Planner verification of Reactive Power in accordance with the requirements of Attachment 1 of MOD-025-2 R2. UNWP had 68 hydro-generating units applicable to this standard and requirements that it failed to verify its Reactive Power capabilities of at least 40% of as it assumed the incorrect effective date of the Standard. UNWP misunderstood the one-hour soak requirement for lagging Reactive Power capacities as required by Attachment 1, section 2.1.1. Because of this oversight, UNWP was unable schedule testing in accordance with the effective date of the Standard. The root cause of the issue was UNWP's misunderstanding of the testing specifications for the Requirement. Specifically, UNWP overlooked the one-hour soak time of the maximum Real Power and lagging Reactive Power capacity as required in Attachment 1 section 2.1.1. Subsequently, the testing was not scheduled in accordance with the accurate implementation schedule.
Risk Assessment	These issues posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, UNWP failed to provide its Transmission Planner verification of Reactive Power in accordance with the requirements of Attachment 1 of MOD-025-2 R2. Such failures could potentially result in inaccurate information of generator gross and net Reactive Power capabilities used in planning models which are used to assess BES Reliability. Inaccurate information would result in inaccurate models; therefore, the BES could be planned with the expectation that a generator has the capability to mitigate a modeled system contingency, whereas it may not completely mitigate the contingency. UNWP owns and/or operates 68 applicable units location at eight facilities with a total capacity of 6,378 MW, of which 36 units were applicable to these issues. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as minor. However, UNWP implemented the WECC Generating Unit Model Validation testing for all its generating units in the past; therefore, if a real-time contingency that required the generating unit to respond were to occur, the current data would be satisfactory for mitigating the contingency. Additionally, the information obtained through the verification process is merely used for system modeling to develop contingencies and operating limits and not depended upon for real-time operating limits. Based on this, WECC determined that there was a moderate likelihood of causing minor harm to the BPS. No harm is known to have occurred.
Mitigation	To mitigate these issues, UNWP: a. developed a procedure to perform the required testing of MOD-025-2 R1 and 2; b. coordinated with all 8 facilities' Maintenance and Operation departments to determine when each Facilities testing could be performed; c. completed testing on 43% of applicable units; d. completed testing on 54% of applicable units; e. complete the testing on 57% of applicable units; f. completed testing on 72% of applicable units; g. completed testing on 93% of applicable units; and h. four generating units are out of commission for long term service and are unable to be tested. Testing will be complete once these units are ready for commercial service.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017148	MOD-032-1	R2	Judith Gap Energy LLC (JUGE)	NCR05503	7/1/2016	7/27/2017	Self-Certification	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On February 28, 2017, JUGE submitted a Self-Certification stating that, as a Generator Owner (GO), it was in noncompliance with MOD-032-1 R2. In preparation for its upcoming self-certification, JUGE discovered that it had not provided steady-state, dynamics, and short circuit modeling data for its 180 MW of wind generation to its Transmission Planner (TP) and Planning Coordinator (PC) according to the data requirements and reporting procedures developed by its TP and PC in Requirement 1. Furthermore, the required data had not been gathered or prepared for distribution prior to the identification of the noncompliance The root cause of the issue was an administrative oversight causing JUGE to fail to gather and provide the required data to its TP and PC. Specifically, JUGE did not have adequate compliance tracking mechanisms in place to ensure that the required data was collected and provided to the TP and PC. This issue began on July 1, 2016, when the Standard became mandatory and enforceable and ended on July 27, 2017, when JUGE provided its modeling data for a total of 392 days of noncompliance.
Risk Assessment	WECC determined that this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, JUGE failed to provide steady-state, dynamics, and short circuit modeling data to its TP and PC according to the data requirements and reporting procedures developed by its TP and PC in Requirement 1, as required by MOD-032-1 R2. Such failure could result in inaccurate data modeling in planning for meeting system operating conditions and addressing contingencies to be created by the TP and PC. Inaccurate modeling could have led to an unexpected loss of the 180 MW of wind generation that was applicable to this issue. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as negligible. However, the data missing was applicable to 180 MW of wind generation and contributes only 135 MW to the grid while operating and operates at an average 38% capacity factor. Based on this, WECC determined that there was a low likelihood of causing negligible harm to the BPS. No harm is known to have occurred.
Mitigation	To mitigate this issue, JUGE: a. submitted to MOD-032 data model to its TP and PC; b. created an automated task notification in its internal task management system to remind SMEs 60 days prior to the end of the 12-month review period; c. created a new policy to escalate incomplete compliance tasks to the compliance team if the tasks are not complete within 30 days of receiving the task notification; and d. entity's new Compliance Manager reviewed the model guidelines and discussed the annual future model update expectations with team.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019956	PRC-024-2	R1	Agua Caliente Solar LLC (AGCS)	NCR11209	7/1/2016	7/25/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 29, 2018, AGCS submitted a Self-Report stating that, as a Generator Operator, it was in violation with PRC-024-2 R1. Specifically, AGCS reported that it did not set the protective relaying settings correctly on its solar generating Facility per the requirements of PRC-024-2 R1, Attachments 1 by July 1, 2016. AGCS's parent corporation, reported that it implemented a plan in 2015 that included its entire fleet of generating Facilities within the Western Interconnection for a single compliance approach. However, in March 2017, AGCS's parent corporation changed this incorrect approach based upon NERC guidance to demonstrate compliance with the Standard on a Registered Entity basis rather than its entire fleet of generating Facilities. As a result of this guidance, AGCS then completed the required analyses and required adjustments of its inverter frequency and voltage trip settings for its applicable Facility; one solar generating unit which generates 320 MWA, on July 25, 2017. After reviewing all relevant information, WECC determined that AGCS failed to set its protective relaying frequency and voltage trip settings, such that the inverters did not trip the solar generator Facility within the "no trip one," as required by PRC-024-2 R1 and R2, Attachments 1. The root cause of these issues was due to the incorrect interpretation of the implementation of PRC-024-2 R1, by AGCS and by its parent company. Specifically, that the implementation plan applied to the entire fleet of solar generating Facilities owned by AGCS's parent company, instead of the implementation plan applying to individual entities that AGCS's parent company owned separately. This incorrect interpretation resulted in AGCS missing the compliance deadline specified in the implementation plan. WECC determined that the issues began on July 1, 2016, when AGCS failed to change its generating unit's inverter settings and ended on July 25, 2017, when AGCS changed the inverters to not trip within the "no trip zone," for a total of 390 days of noncompliance.
Risk Assessment	WECC determined that these issues posed a minimal risk and did not pose a serious and substantial risk to the reliability of the Bulk Power System (BPS). In these instances, AGCS failed to set its protective relaying frequency and voltage trip settings, such that the inverters did not trip the solar generator Facility within the "no trip one," as required by PRC-024-2 R1. Such failure could potentially result in the premature tripping of the generating Facility due to voltage excursions within the "no trip zone." AGCS owns and operates 242 MVA solar generating Facility that was applicable to this issue. Its previous setting for under-frequency would have operated between 57 - 59.3 Hz for 0.16 seconds before tripping within the "no trip zone." If the Facility had experienced a voltage excursion, its previous setting for under-voltage would have operated at 0.5 pu voltage for 0.16 seconds before tripping within the "no trip zone." Therefore, WECC assessed the potential harm to the security and reliability of the BPS as minor. AGCS implemented weak preventative controls to prevent the above issue from occurring. Specifically, AGCS's parent corporation provided compliance support to AGCS through its corporate regulatory compliance program that contributed to this issue. However, the 242 MVA is an intermittent resource and there was no substation frequency and voltage ride through trips equipped at this Facility. Based on this, WECC determined that there was a low likelihood of causing minor harm to the BPS. No harm is known to have occurred. WECC determined that AGCS has no relevant compliance history for this noncompliance.
Mitigation	AGCS completed mitigating activities to address its issues with the Standards and WECC verified AGCS's mitigating activities. To remediate and mitigate these issues, AGCS: a. completed analysis for frequency and voltage trips for the Facility and adjusted the inverter settings as required by the Standard; and b. instituted an internal quarterly control measures form to identify any changes in its frequency and voltage settings to ensure compliance with the Standard. This form states that the plant personnel are required to document proposed inverter frequency and voltage setting changes and notify the engineering group prior to making any changes. The plant personnel must select an appropriate statement from a list of scenarios including whether or not changes have been made to the inverter frequency and voltage settings and whether they were communicated to the engineering and consultants to verify compliance.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2018019957	PRC-024-2	R2	Agua Caliente Solar LLC (AGCS)	NCR11209	7/1/2016	7/25/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On June 29, 2018, AGCS submitted a Self-Report stating that, as a Generator Operator, it was in violation with PRC-024-2 R2. Specifically, AGCS reported that it did not set the protective relaying settings correctly on its solar generating Facility per the requirements of PRC-024-2 R2, Attachments 2 by July 1, 2016. AGCS's parent corporation, reported that it implemented a plan in 2015 that included its entire fleet of generating Facilities within the Western Interconnection for a single compliance approach. However, in March 2017, AGCS's parent corporation changed this incorrect approach based upon NERC guidance to demonstrate compliance with the Standard on a Registered Entity basis rather than its entire fleet of generating Facilities. As a result of this guidance, AGCS then completed the required analyses and required adjustments of its inverter frequency and voltage trip settings for its applicable Facility; one solar generating unit which generates 320 MWA, on July 25, 2017. After reviewing all relevant information, WECC determined that AGCS failed to set its protective relaying frequency and voltage trip settings, such that the inverters did not trip the solar generator Facility within the "no trip one," as required by PRC-024-2 R2, Attachments 2. The root cause of these issues was due to the incorrect interpretation of the implementation of PRC-024-2 R2, by AGCS and by its parent company. Specifically, that the implementation plan applied to the entire fleet of solar generating Facilities owned by AGCS's parent company, instead of the implementation plan applying to individual entities that AGCS's parent company owned separately. This incorrect interpretation resulted in AGCS missing the compliance deadline specified in the implementation plan. WECC determined that the issues began on July 1, 2016, when AGCS failed to change its generating unit's inverter settings and ended on July 25, 2017, when AGCS changed the inverters to not trip within the "no trip zone," for a total of 390 days of noncompliance.
Risk Assessment	WECC determined that these issues posed a minimal risk and did not pose a serious and substantial risk to the reliability of the Bulk Power System (BPS). In these instances, AGCS failed to set its protective relaying frequency and voltage trip settings, such that the inverters did not trip the solar generator Facility within the "no trip one," as required by PRC-024-2 R2. Such failure could potentially result in the premature tripping of the generating Facility due to voltage excursions within the "no trip zone." AGCS owns and operates 242 MVA solar generating Facility that was applicable to this issue. Its previous setting for under-frequency would have operated between 57 - 59.3 Hz for 0.16 seconds before tripping within the "no trip zone." If the Facility had experienced a voltage excursion, its previous setting for under-voltage would have operated at 0.5 pu voltage for 0.16 seconds before tripping within the "no trip zone." Therefore, WECC assessed the potential harm to the security and reliability of the BPS as minor. AGCS implemented weak preventative controls to prevent the above issue from occurring. Specifically, AGCS's parent corporation provided compliance support to AGCS through its corporate regulatory compliance program that contributed to this issue. However, the 242 MVA is an intermittent resource and there was no substation frequency and voltage ride through trips equipped at this Facility. Based on this, WECC determined that there was a low likelihood of causing minor harm to the BPS. No harm is known to have occurred. WECC determined that AGCS has no relevant compliance history for this noncompliance.
Mitigation	AGCS completed mitigating activities to address its issues with the Standards and WECC verified AGCS's mitigating activities. To remediate and mitigate these issues, AGCS: a. completed analysis for frequency and voltage trips for the Facility and adjusted the inverter settings as required by the Standard; and b. instituted an internal quarterly control measures form to identify any changes in its frequency and voltage settings to ensure compliance with the Standard. This form states that the plant personnel are required to document proposed inverter frequency and voltage setting changes and notify the engineering group prior to making any changes. The plant personnel must select an appropriate statement from a list of scenarios including whether or not changes have been made to the inverter frequency and voltage settings and whether they were communicated to the engineering and consultants to verify compliance.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017040	IRO-010-1a	R3	Puget Sound Energy, Inc.	NCR05344	4/1/2016	1/24/2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	PSE discovered February 16, 2017 that it inadvertently supplied inaccurate or incomplete information in response to an ongoing data request from its Reliability Coordinator (RC). PSE's four data items that were not accurately and completely provided to the RC were: a. PSE's hourly Unit Commitment for all BA Area generation that qualifies per the BES definition and any non-BES generation (as determined by RC) that is necessary to support the accuracy of Operational Planning Analyses and to determine any SOL exceedance on BES Facilities. This information is required to be submitted daily; by 10 a.m. Pacific Prevailing Time, for the current day through the next four business days; b. PSE's hourly Unit Commitment for all BA Area generation that qualifies per the BES definition and any non-BES generation (as determined by the RC) that is necessary to support the accuracy of Operational Planning Analyses and to determine any SOL exceedance on BES Facilities 10 minutes prior to the hour, every hour, plus the next four hours; c. PSE's Hourly Operational Minimum MW for all BA Area generation that qualifies per the BES definition and any non-BES generation (as determined by Peak RC) that is necessary to support the accuracy of Operational Planning Analyses and to determine any SOL exceedance on BES Facilities. This information is required to be submitted daily; by 10 a.m. Pacific Prevailing Time, for the current day through the next four business days; and d. PSE's Hourly Operational Minimum MW for all BA Area generation that qualifies per the BES definition and any non-BES generation (as determined by the RC) that is necessary to support the accuracy of Operational Planning Analyses and to determine any SOL exceedance on BES Facilities 10 minutes prior to the hour, every hour, plus the next four hours. When the data request was issued, PSE staff created the reporting formulas in the MCG Energy Solutions software (MCG), which reports the data to the RC. However, the data that was generated by MCG was not verified to be accurate prior to sending the information to the RC. Specifically, when MCG made its calculation, it was using business days instead of calendar days, causing the transmitted data to be inaccurate. Additionally, MCG was reporting inaccurate data due to Pmax and Pmin values being calculated inaccurately during outages. The root cause of the issue was PSE's lack of internal controls. Specifically, PSE did not verify the calculations and resulting data generated in its MCG for accuracy prior to starting the automated data transmittal. WECC determined that this issue began on April 1, 2016, when the first inaccurate dataset was sent to the RC and ended on January 24, 2017, when PSE provided complete and accurate data to the RC for a total of 298 days of noncompliance.
Risk Assessment	WECC determined that this issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In these instances, PSE failed to provide data and information, as specified, to its RC, as required by IRO-010-1a R3, to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area. Such failure could cause the RC to use inaccurate generating capacities in the development of its Operating Plan. Inaccurate capabilities in the Operating Plan may affect real-time or contingent conditions leading to unexpected load shedding and delayed system restoration after an event. PSE owns and/or operates 3711 MW of generation that was applicable to this issue. However, the RC had indicated that the four data items were used primarily for forecasting studies and not daily operations studies. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as minor. Additionally, PSE is a member of a reserves sharing group which made additional generation available if PSE was unable to meet the generation requirements of the Operating Plan. Based on this, WECC determined that there was a low likelihood of causing minor harm to the BPS. No harm is known to have occurred.
Mitigation	To mitigate this issue, PSE: a. permanently changed the MCG calculation methodology to report on calendar days and not business days. The spreadsheet shows that the schedule for submitting the generation forecast was changed from the current day plus four to the current day plus seven. This modification corrected a logic error in the MCG's methodology for populating unit commitment schedules so that it would provide seven full calendar days of data; and b. Establish process to update the Pmax and Pmin values manually in MCG when generation availability changes. The document indicates that the entity established a daily calendar reminder to have the outage coordination personnel in its load office update the minimum and maximum values manually in the application when there is a generation availability change. Page 2 of the document demonstrates that a report is pulled from RC's coordinated outage system to determine if any new outages are scheduled to occur or if any unscheduled generation outages happened as indicated from the COS. This information is then entered into the MCG application which is submitted directly to the RC.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
WECC2017017309	BAL-001-2	R2	Western Area Power Administration - Desert Southwest Region (WALC)	NCR05461	9/6/2016	9/6/2016	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On March 27, 2017, WALC submitted a Self-Report stating that, as a Balancing Authority (BA), it was in noncompliance with BAL-001-2 R2. On September 6, 2016, the WALC SCADA system was failing to update its information between it and the Bureau of Reclamation (Bureau), which is essential for generation control of 1539 MW from the Hoover power plant. The WALC System Operator called the Hoover Operator inquiring about the values they were seeing and the Hoover control status confirmed WALC's data was not updating. The WALC System Operator requested the Hoover Operator switch his communication channel from "A" to "B", then back to "A" again, to which he observed no resolution. The WALC System Operator then called SCADA Support who suggested that the WALC System Operator log into the ECC Server to check for better visibility, however, the ECC server was not updating either. In the interim, the WALC System Operator called the Hoover Operator to verify generation output levels, on-line capacity, and control status. SCADA support then rebooted the servers and the Data Link appeared to be restored. The WALC System Operator verified with the Hoover Operator that the plant was receiving data and generating to the correct value, but the Data Link issue reoccurred. The WALC System Operator then requested the Hoover Operator call their SCADA personnel to restart their servers. In the interim, WALC's SCADA Support rebooted the WALC servers again and successfully restored the Data Link. The WALC System Operator observed WAPA data updating again and called the Hoover Operator to validate the generation data. Finally, the WALC Operator logged the BAAL exceedance of 39 minutes and reported the exceedance and the Data Link status to the Desk Supervisor (Start BAAL exceedance minute count at 21:02; End BAAL exceedance minute count at 21:40 (39 minutes)). The root cause of the issue was WALC's System Operator failed to follow the established procedure by taking manual control of the communication system when the Data Link failed to transmit accurate data between WALC and the Bureau. This issue began on September 6, 2016, when WALC's clock minute average of reporting ACE exceeded the clock-minute Balancing Authority ACE Limit for the 31st minute and ended on September 6, 2016, when its Data Link servers were rebooted, for a total of 9 minutes of noncompliance.
Risk Assessment	This issue posed a minimal risk and did not pose a serious or substantial risk to the reliability of the Bulk Power System (BPS). In this instance, WALC failed to operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit for more than 30 consecutive clock-minutes calculated in accordance with Attachment 2, as required by BAL-001-2 R2. Such failure could have caused an interconnection frequency excursion outside of defined limits. WALC balances 3066 MW of generation, of which, 1539 MW were applicable to this issue. Therefore, WECC assessed the potential harm to the security and reliability of the BPS as intermediate. However, WALC was still able to monitor the interconnection from its Reliability Messaging Tool to verify that there was no loss of generation, load or transmission. The generator was aware of the situation, still receiving data and was able to monitor in real-time. Lastly, If the frequency excursions had been detected, WALC would likely have corrected the condition as the entity has implemented strong corrective controls. WALC is part of a reserve sharing group that could have provided more generation if necessary. Based on this, WECC determined that there was a low likelihood of causing intermediate harm to the BPS. No harm is known to have occurred.
Mitigation	To mitigate this issue, WALC: a. Returned to operate such that the BAAL limit does not exceed 30 minutes; b. Notified and trained System Operators of the existing procedure to be followed for Data Link failures.