### Description of the Violation

During a Compliance Audit conducted from June 13, 2017 to October 3, 2017, SERC determined that Ameren, as a Transmission Owner, was in violation of FAC-008-3 R6. SERC determined that the violation started under FAC-009-1 R1 and ended under FAC-008-3 R6. Ameren did not have Facility Ratings that were consistent with its Facility Ratings methodology (FRM).

During the on-site audit, the SERC audit team conducted facility walk-downs. SERC identified discrepancies between the FRM and the established element Ratings in the database for the Big River facility and the one-line drawing for the Spencer Creek facility, neither of which impacted the Facility Rating. The audit team found that Ameren had recently revised the database and substation one-line drawings. After the audit, and in response to a request for additional information to determine the complete scope of the discrepancies, Ameren conducted a system walk-down to review the accuracy of the physical components against the current system drawings. Ameren reviewed each element Rating to ensure they were consistent with its FRM, identified the Most Limiting Element (MLE), and established the correct Facility Rating. Ameren reviewed the Facility Rating used in operations and compared it with the Rating of the MLE for each Facility. As a result of this review, Ameren identified incorrect element Ratings for 2,816 of 27,330 (10.3%) elements at 56 of 297 transmission Facilities, 6 of which had both up-rates and de-rates. Ameren made corrections to the Facility Ratings, which resulted in 29 Facility Rating decreases (with a range from 0.1% to 37.2%) and 27 Facility Rating increases (with a range from 2.5% to 119.2%). Also, five of the five 297 facilities (all of the facilities were derated) experienced exceedances of the correct Facility Ratings. The number of exceedances at the facilities ranged from one to 36 in a one year period. Overall, there were 62 exceedances during this time period.

This noncompliance started on June 18, 2007, when the Standard became mandatory and enforceable, and ended on December 14, 2018, when Ameren corrected its last incorrect element Rating.

### Risk Assessment

This violation posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Ameren’s failure to establish Facility Ratings that were consistent with its FRM could have resulted in erroneous outage planning, violations of System Operating Limits, damage to Facilities, and incorrect coordination with interconnecting systems. However, the risk to the BPS was mitigated because all five facilities that exceeded the Facility Rating were limited to lower voltage, 138 kV transmission facilities. No harm is known to have occurred.

### Mitigation

To mitigate this violation, Ameren:

1. developed and implemented a change management process to capture any element and Overall Facility Rating changes to BES Facilities during unplanned and planned outages;
   a. The change management process for planned outages includes independent verifications on the design, the ratings database accuracy and to verify the constructed facilities are correct;
   b. The change management process for unplanned outages includes an independent verification on the components installed and the ratings database entry; and
   c. The change management process is an automated process that utilizes an electronic approval of the tasks and verifications prior to placing planned projects in-service;
2. communicated the new process to the appropriate individuals;
3. hired two independent consulting firms to complete the walk-downs of Ameren’s 297 substation Facilities to identify any additional discrepancies;
4. communicated the results of the initial walk-downs to SERC staff on a quarterly basis in 2018; and
5. performed a reverification of the walk-down results.

### Other Factors

- SERC reviewed Ameren’s internal compliance program and considered it to be a neutral factor in the penalty determination.
- SERC awarded mitigating credit for Ameren’s cooperation and settlement of the enforcement action.
- SERC considered Ameren’s compliance history and determined that there were no relevant instances of noncompliance.

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### SERC Reliability Corporation (SERC) Settlement Agreement

#### O&P

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### 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 June 13, 2017 to October 3, 2017, SERC determined that AUE, as a Generator Owner, was in violation of FAC-008-3 R6. SERC determined that the violation started under FAC-009-1 R1 and ended under FAC-008-3 R6. AUE did not have Facility Ratings that were consistent with its Facility Ratings methodology (FRM).

During the on-site audit, the SERC audit team conducted a facility walk-down of the Peno Creek and Pinckneyville facilities, and identified discrepancies between the FRM and the established element Ratings at both generating facilities. After the audit and in response to a Request for Additional Information to determine the complete scope of the discrepancies, AUE conducted a system walk-down of all AUE generating facilities to review the accuracy of the physical components against the current system drawings. AUE reviewed each element Rating to ensure they were consistent with its FRM, identified the Most Limiting Element (MLE), and established the correct Facility Rating for all of its generating facilities. AUE reviewed the Facility Rating used in operations and compared it with the Rating of the MLE for each Facility. As a result of this review, AUE discovered that it did not establish Facility Ratings in accordance with its FRM on 18 of its 63 generating facilities. AUE made corrections to the Facility Ratings, which resulted in 15 Facility Rating decreases (with a range from 1.8% to 70.8%) and three Facility Rating increases (12.5%). Also, 10 of the 18 facilities, all of which were derated, experienced exceedances of the correct Facility Ratings. As Osage 7 & Osage 8 share a common bus, the exceedance is only on the bus and not on each facility. The number of exceedances at the facilities ranged from one to 161 during a one year period. Overall, there were 762 exceedances during this time period.

This noncompliance started on June 18, 2007, when the Standard became mandatory and enforceable, and ended on December 11, 2018, when AUE corrected its last incorrect Rating. The cause of this violation was management oversight for failing to implement a change control process to verify element changes and that such changes were reflected in its ratings database and substation one-line diagrams.

### Risk Assessment

This violation posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). AUE’s failure to establish Facility Ratings that were consistent with its FRM could have resulted in the conductors, buses, and breakers overheating and failing, resulting in unit trips. The risk was moderate because the highest Facility Rating discrepancy at the AUE facilities was 70.8%, and five facilities had over 100 exceedances (161, 113, 110, 108, and 104). However, the risk was mitigated because AUE’s total generation impacted by incorrect Facility Ratings was 1,436 MW, which was a small amount of generation in the MISO Reliability Coordinator (RC) area; therefore, the impact to the MISO RC area from AUE unit trips was small. Moreover, the 1,436 MW of impacted generation is 14.58% of AUE’s total 9,849 net MWs of generation. No harm is known to have occurred.

### Mitigation

To mitigate this violation, AUE:

1. hired consultants to perform walk downs at 100% of its 63 generating facilities to verify Facility Rating components in order to correctly rate the overall Facility Rating;
2. revised its FAC-008 program procedure to include a verification process to validate Facility Ratings and to require an independent reviewer to verify accuracy of the Ratings;
3. communicated changes to the procedure to Subject Matter Experts;
4. established a weekly report of all maintenance jobs created by the Energy Centers that involve components from the Generator output terminals to the transmission tie point, to be reviewed for impacts to the FAC-008 program;
5. established a point of reporting responsibility for all generating units, which is documented in the FAC-008 program documents;
6. created an internal commitment in the Ameren commitment tracking system to conduct sample audits at three randomly selected energy centers every three years to ensure compliance with FAC-008-3;
7. added an independent reviewer signature line for Visio diagram changes; and
8. completed an additional walk-down of 100% of Ameren’s 63 generation facilities in Q1 2020 to validate the Maximum Equipment Rating one-line diagrams.
9. bolstered the existing change management process to better defined the types of design changes that warrant facility rating document updates.

### Other Factors

SERC reviewed AUE’s internal compliance program and considered it to be a neutral factor in the penalty determination.

SERC awarded mitigating credit for AUE’s cooperation and settlement of the enforcement action.

SERC considered AUE’s compliance history and determined that there were no relevant instances of noncompliance.
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 21, 2018, the Eversource Energy Service Company (the entity) provided a Self-Log to NPCC stating that, as a Transmission Owner (TO), it was in noncompliance with FAC-008-3 R6. During the investigation of the violation, and based on an extent of condition performed by the entity after the Self-Log, NPCC determined the violation was of moderate risk to the reliability of the bulk power system and, as such, did not qualify as a Compliance Exception. NPCC further determined that the entity was in violation of FAC-009-1 R1 from June 21, 2007 until December 31, 2012 and in violation of FAC-008-3 R6 from January 1, 2013 until May 9, 2019. For purposes of this violation, there was no substantive change in the entity’s compliance obligations under the two applicable Standard Requirements.

During the preparation for an upcoming on-site audit, the entity discovered on May 10, 2018 that the in-use Facility Ratings on three 345 kV transmission lines and three 345/230 kV autotransformers in the Eastern Massachusetts Area (EMA) did not align with the entity’s Facility Rating Methodology (FRM). Upon further investigation, the entity determined that the violation was limited to the EMA, which has different internal controls, IT systems, and procedures than the other the entity areas. A full extent of condition was performed on all 262 EMA BES Elements, and the entity performed several tests of the Facility Ratings throughout the entity service territory. After the extent of condition, there were 65 instances where the in-use Facility Rating could not be correlated to the current FRM. The 65 instances are composed of issues with the following Elements: 12 345-kV Transmission Lines, 32 115-kV Transmission Lines, and 21 Autotransformers.

For the 44 Transmission Lines, there were 14 instances where equipment in the field was modified, but the Facility Ratings were not updated. There were also three instances where the entity failed to consider series limiting components (station tap wires). The remaining 27 Transmission Line instances and all 21 of the autotransformer instances include the use of legacy calculations based on industry rating practices (IEEE, ANSI), but which did not follow the FRM or for which the calculations could not be replicated.

For eight 115 kV Transmission Lines, the Facility Ratings did not consider the distance from the conductor to the ground.

The new BES definition came into effect on July 1, 2016. Of the 65 instances in this violation, 59 of them apply to Elements that were part of the BES definition as of June 21, 2007. The remaining six instances (all 115-kV lines) apply to Elements that became part of the BES definition on July 1, 2016.

By March 1, 2019, the entity completed the determination of the correct final Facility Rating for all 65 Elements, including the determination of the Interim Summer 2019 ratings. By May 9, 2019, the entity provided the interim and/or final updated Facility Ratings to ISO-NE.

NPCC determined that the entity was in violation of FAC-009-1 R1 from June 21, 2007 until December 31, 2012 and then was in violation of FAC-008-3 R6 from January 1, 2013 until May 9, 2019.

The entity is the TO for 869 BES Elements, made up of 103 345-kV lines, five 230-kV lines, three 138-kV lines, 521 115-kV lines, 66 Autotransformers, and 171 other types of station equipment. Based on the quantity of Facility Rating errors (65/869 = 7.4%), the Violation Severity Level is Moderate. Although the Violation Severity Level is Moderate, of the 65 Facilities, 30 Facilities had only a minimal (less than 3%) or positive increase change from the original rating for all Normal or Long Time Emergency (LTE) ratings.

The current entity footprint in EMA is made up of the amalgamation of multiple electric companies over the last 60 years. The primary root cause of this violation was prior management’s insufficient review process of historical ratings associated with the EMA area and failure to perform a comparison with the current documented FRM in use by the entity. In addition, in 2016, a documented process did not exist that would consistently ensure that transmission fieldwork results were analyzed by Transmission Line Engineering before a field project was closed out.

Risk Assessment

The violation posed a moderate risk to the reliability of the bulk power system. The entity’s failure to establish accurate Facility Ratings in 65 instances increased the potential for its Facilities to be operated outside of their correct capacity rating, creating the opportunity for equipment damage, incorrect modeling outputs and operating assumptions. In particular, the use of incorrect Facility Ratings in the Energy Management System (EMS) could negatively impact reliability under stressed system conditions as the System Operator may unknowingly operate to a higher rating than the equipment can accommodate. Planning and operating studies depend on the use of accurate book ratings such that the BES can withstand a variety of predetermined contingencies.

Northeast Power Coordinating Council, Inc. (NPCC)

Settlement Agreement

Entity Response - Admits

Eversource Energy Service Company – NCR07176

NERC Violation ID | Reliability Standard | Req. | Violation Risk Factor | Violation Severity Level | Violation Start Date | Violation End Date | Method of Discovery | Mitigation Completion Date | Date Regional Entity Verified Completion of Mitigation |
|------------------|---------------------|------|-----------------------|-------------------------|----------------------|------------------|----------------------|-----------------------------|-----------------------------------------------|
For the eight instances where there were conductor to ground clearance issues, three of them had equipment work performed in the field after the completion of the NERC FAC Alert review in 2012 and would have benefitted from the implementation of the correct controls to determine correct Facility Ratings.

However, the risk posed by this violation was mitigated by a number of factors. Although there was a degree of inaccuracy involved, the EMA Facility Ratings were developed based on good utility practices using sound engineering judgment for the assumptions and methodology applied at the time. The entity provided historical data that showed that there were no instances where an affected Facility was historically operated in Real-time over its final corrected Facility Rating or its Summer or Winter 2019 Interim ratings.

The entity is in a summer peaking load area. Of the 65 BES Elements with incorrect Facility Ratings, 27 had a corrected Summer Normal Facility Rating that was lower than the entity’s System Operators had been operating in the EMS before the discovery. Of those 27, the maximum percentage of rating inaccuracy was 24% of the Summer Normal rating on a 115 kV transmission line. The percentage of Summer ratings correction on BES Elements where the corrected Facility Rating is lower is as follows:

- 0 – 10% - 21 Elements
- 11-20% - 5 Elements
- 21% or more – 1 Element

No harm is known to have occurred.

Mitigation

To mitigate the violation and to prevent recurrence of the violation, the entity:

1. Performed an extent of condition review by evaluating the existing Facility Rating calculations for all 262 Elements in the EMA area to determine if such Facility Ratings could be replicated based on the documented FRM. If the Facility Rating could not be replicated, it was recalculated using up to date field surveys and LiDAR data;
2. Calculated the correct Facility Ratings for all 65 Elements and input them into the Thermal Ratings Analyzer;
3. Provided the updated and correct Facility Ratings for all 65 Elements to ISO-NE;
4. Expanded its Thermal Ratings Coordinator (TRC) function into the EMA area. Created a new local Thermal Ratings Coordinator (LTRC) position in the EMA area. This person works with engineering and is responsible for facilitating the coordination and development of individual Facility Ratings in the EMA area. In particular, for all transmission related new construction, equipment modifications and/or upgrades, and certain maintenance projects, the TRC function ensures the consistent application of the Facility Rating milestones are documented and tracks each project associated Facility Rating implementation to completion;
5. Established a Facilities Rating Update Request System (SharePoint site) to document all Facility Rating changes for new construction, equipment modifications or data updates and document manager reviews and approvals;
6. Amended the overhead ratings procedure to reflect a consistent approach across all three states and to mandate that all new facility ratings must comply with documented methodology.
7. Incorporated the expectations associated with the entity Transmission Facility Ratings procedure into weekly Key Performance Indicator (KPI) meetings and into monthly project meetings where Facility Ratings projects are discussed;
8. Conducted 13 training awareness sessions to engineering, project management and field engineering/operations personnel to discuss the violation, emphasize the specific controls relevant to the audience and highlight the importance of compliance with FAC-008-3; and
9. Completed physical field remediation for the eight conductor to ground clearance issues.

Other Factors

NPCC reviewed the entity’s internal compliance program (ICP) and considered it to be a neutral factor in the penalty determination. Although the entity has a mature and effective NERC Reliability Compliance Program, the duration of the violation did not warrant awarding mitigating credit.

NPCC considered the entity’s and its affiliate’s compliance history in determining the penalty. NPCC determined that the entity’s affiliate had one relevant previous violation. NPCC determined that the previous violation was not an aggravating factor because the root cause and the subject equipment of the previous violation differs from the instant violation. Additionally, the actions to mitigate the previous violation would not have prevented or identified this violation.

NPCC applied mitigation credit in the penalty determination because the entity was cooperative throughout the enforcement process, admitted to the violation, and agree to settle the violation.
On April 7, 2017, Exelon Nuclear submitted a Self-Report stating, as a Generator Owner (GO), it was in violation of PRC-005-1.1b R2. (R2.1.). Following extent of condition reviews, Exelon Nuclear updated its Self-Report on August 11, 2017, January 24, 2018, and October 1, 2018.

Exelon Nuclear did not perform testing in accordance with its Protection System Maintenance Program ("PSMP") for:

(a) Thirteen (13) out of 111 Current Transformers (CTs) and nine (9) out of 150 sections of DC control circuitry at the R.E. Ginna Nuclear Power Plant (Ginna). Specifically, this included (i) two (2) sets of the three-phase CTs (six (6) total CTs) that are associated with the 4kV side of the 19/4kV auxiliary transformer differential relay. The auxiliary transformer is directly connected to the main generator and the 19/115kV step up transformer. (The 19kV side CT set associated with the differential relay was tested in accordance with Exelon’s PSMP). (ii) Two (2) other sets of three-phase CTs (six (6) total CTs) associated with the generator differential relay. One (1) set of CTs is at the neutral terminals of the main generator, and the other set is at the line terminals of the main generator. (iii) One (1) single phase CT associated with a generator backup directional distance relay for remote transmission faults.

It also included (iv) seven (7) sections of DC control circuitry that terminate at Ginna owned breaker trip coils that come from the Transmission Owner breaker backup relays associated with off-site power supply to Ginna. (v) One (1) section of DC control circuitry that terminates at one of the two Ginna output breaker trip coils that come from Transmission Owner breaker backup relays associated with off-site power supply to Ginna. (vi) one (1) section of DC control circuitry from the breaker backup relay to the trip coil of a downstream Ginna breaker that would be sent a signal to open if the particular Ginna output breaker fails to trip when called upon (associated with one of the two Ginna output-breakers).

(b) Fifty-two (52) out of 372 sections of DC control circuitry and one (1) out of 180 relays at Nine Mile Point Nuclear Station, Units 1 (NMP1). Specifically, this included (i) fourteen (14) sections of the DC control circuitry that terminate at breaker trip coils that are associated with the primary breaker backup protection and the secondary breaker backup protection associated with the two NMP1 output breakers. (ii) Fifteen (15) sections of the DC control circuitry that terminate at breaker trip coils associated with one of the two routes of redundant protection schemes on two (2) - 115kV Transmission Owner lines that provide offsite power to NMP1. (iii) Twenty (20) sections of the DC control circuitry that terminate at breaker trip coils that are associated with redundant differential protection on each of the two (2) transformers that provide off-site power to NMP1 from the two (2) 115kV Transmission Owner lines, (iv) Three (3) sections of DC control circuitry associated with a main generator exciter volts/hertz protective relay to the lockout relay and (v) one (1) breaker generator undervoltage protection relay that trips one of the two NMP1 output breakers.

(c) Nineteen (19) out of 372 sections of DC control circuitry at its Nine Mile Point Nuclear Station, Units 2 (NMP2). Specifically, this included (i) sixteen (16) sections of DC control circuitry that terminate at various Transmission Owner breaker trip coils that are associated with the redundant differential protection schemes on each of the 345/115kV transformers that provide off-site power to NMP2 from the Transmission Owner’s system and (ii) three (3) sections of DC control circuitry between the generator exciter Volts/Hertz relay and the multi-purpose lockout relay.

(d) Forty-three (43) out of 150 sensing devices, thirteen relays, eight sudden pressure relays, and four associated pressure sensors at its Jame A. FitzPatrick Nuclear Power Plant (FitzPatrick). Specifically, this included (i) six (6) sensing devices (four (4) Potential Transformers (PTs), one (1) CT1 and one (1) neutral transformer) associated with generator volts per hertz protection and the generator stator ground fault protection (neutral overcurrent and neutral overvoltage), (ii) twelve (12) CTs (4 CTs with 3 phases each) associated with Main Generator Exciter differential protection. (iii) Three (3) CTs on the high-voltage (HV) bushing of the Station Auxiliary Transformer (SAT) differential relay, (iv) three (3) CTs also on the HV side bushings of the SAT that feed an instantaneous/time overcurrent relay (v) fifteen (15) CTs on the low side (4.16 kV) of the SAT that also feed the SAT differential relay, (vi) two (2) CTs on the X and Y winding neutrals that feed neutral overcurrent relays. (vii) two (2) Main Power Transformer neutral CTs that feed the overcurrent relay for the “A” and “B” Main Power Transformers. These relays provide backup protection for system faults. (viii) thirteen (13) relays associated with an overcurrent protective scheme on the 115 kV system. (ix) eight (8) sudden pressure relays and four (4) associated pressure sensors that support one of the two main power transformers.

NPCC determined that the overall root cause of the violation at Ginna, NMP1, and NMP2 was the lack of proper management oversight and attention to detail in the implementation of the Exelon PSMP as the ERO was transitioning from PRC-005-1b to PRC-005-2/6. A contributing factor was that Exelon became the GO and Generator Operator ("GPO") in December 2014 for the three units and there was the need to reconcile the maintenance that was completed by the previous GO with the incoming Exelon PSMP. As such, much of the testing that was not completed was inherited by Exelon. However, there were some aspects of the missed testing that could have been performed after the acquisition had the Exelon Nuclear PSMP not lacked clarity for the performance of those specific maintenance/test activities.

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At Ginna, NMP1, and NMP2, the duration of the violation is approximately 4 years spanning from December 5, 2014 (effective date of the Exelon Nuclear GO registration for those 3 sites) to December 12, 2018.

NPCC determined that the root cause of the violation at FitzPatrick was the lack of proper implementation and documentation of the PRC-005 program by the previous plant owner. The previous owner announced in 2015 that the plant would close in January 2017. On the March 31, 2017 effective date of Exelon Nuclear being registered as the GO/GOP/TO for the plant, the violations already existed. However, Exelon Nuclear also performed a line-by-line walk down of FitzPatrick PSMP components during the September 2018 refueling outage and failed to identify two (2) DC circuitry components that now cannot be tested until the unit is offline for the Fall 2020 refueling outage. Otherwise, all PRC-005 testing and documentation would have been in place at FitzPatrick at the conclusion of the September 2018 outage.

At FitzPatrick, the violation start date is March 31, 2017 (effective date of GO registration) and the end date will be September 30, 2020 when the two (2) DC circuitry components are tested during the refueling outage.

### Risk Assessment

This violation posed a moderate 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 uncompleted maintenance affected four generating units with an aggregate nameplate rating of approximately 3,375 MW. The failure to maintain and test the affected components could have caused the Protection System to either misoperate or fail to operate. Under certain conditions, this could cause the generating units to either trip offline unnecessarily, operate in an unstable manner potentially leading to cascading outages under stressed system conditions, and/or cause the nuclear site to exceed its Technical Specification for off-site power where a controlled plant shutdown would be initiated.

The Points of Interconnection (POIs) to the BES of the four generating units are in close electrical proximity to one another and in the same generation corridor. In particular, NMP1 and 2 are part of the Oswego Generation Complex, which is listed by the New York Independent System Operator (NYISO) as a stability-constrained Interconnection Reliability Operating Limit (IROL) interface in the New York Control Area. If the violation had caused the loss of all of Exelon Nuclear’s generating capacity during a system event, the aggregate capacity of the four non-compliant generators significantly exceeds the current NYISO daily Operating Reserve of 1,965 MW. However, this would be a highly improbable situation as the overall redundancy associated with the overwhelming majority of the unmaintained aspects of the relay protection systems (e.g. DC wiring associated with the breaker backup relays and redundant transmission line protective relaying) and the other tests performed by Exelon Nuclear that indirectly provided some indication of the functionality of the unmaintained equipment reduced the probability of a misoperation and reduced the risk to the BPS.

No harm is known to have occurred as a result of this violation.

### Mitigation

To mitigate this violation, Exelon Nuclear:

1. completed the maintenance activities at Ginna, NMP1, NMP2 and most of the maintenance activities at FitzPatrick, with the exception of two DC circuitry components associated with relays.
2. performed a line-by-line Protection System component review of all four units to ensure that all activities listed apply to each component listed in the PRC-005 matrix, that all information is aligned to the work control system codes, and that all procedure descriptions are accurate.
3. revised its PSMP procedure to more clearly identify the exciter DC circuitry as being included in the PSMP. Although the procedure already included the exciter DC circuitry, specific references within an addendum were clarified to prevent any possible confusion in the future.
4. developed new site-specific procedures for each of the four generating units that each individual site will have revision and content control over. The PRC-005 matrix for each unit within the procedures was independently reviewed and verified by a contracted third-party engineering firm to ensure that all protection system components were appropriately scoped within Exelon Nuclear’s PRC-005 program.
5. reviewed all governance documents to ensure that adequate prompts and barriers are in place to ensure PRC-005 implications are evaluated for any change.
6. conducted awareness briefings to the Ginna, NMP, and FitzPatrick Site Leadership Teams on the importance of the proper execution and challenge of PRC-005 related maintenance, testing, and scoping.
7. performed a formal benchmarking of a recommended PRC-005 program at another Nuclear GO/GOP to identify lessons learned and best practices.

To mitigate this violation, Exelon Nuclear will

1. Compete the maintenance activities for two DC Circuits at the FitzPatrick unit during the next refueling outage.

### Other Factors

NPCC considered that Exelon Nuclear self-reported this violation and awarded some mitigating credit for self-reporting.

NPCC reviewed the entity’s internal compliance program (ICP) and considered it to be a neutral factor in the penalty determination.

NPCC considered Exelon Nuclear’s compliance history and determined that there is a prior relevant instance of affiliate noncompliance in NPCC and NPCC considered that prior noncompliance to be an aggravating factor in the penalty determination.
In determining the penalty, NPCC concluded that despite some aspects of the missed testing that could have been performed after the acquisition of the New York plants, much of the testing that was identified and found to be incomplete was inherited by Exelon Nuclear. This circumstance limits the aggravation of Exelon Nuclear’s previous compliance history.

As a non-monetary sanction, ReliabilityFirst and NPCC will conduct a spot check of Exelon Nuclear in the summer of 2021 to evaluate Exelon Nuclear’s ongoing compliance with PRC-005-6 R2.
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 5, 2018, Exelon Nuclear submitted a Self-Report to ReliabilityFirst stating that, as a Generator Owner (GO), it was in violation of PRC-005-1.1b R2.

During an extent of condition review, which was performed across the Exelon Nuclear fleet, and the results of which were addressed in mitigation for RFC2016015585, Exelon Nuclear discovered that the procedure section for the Byron Station Unit 1 Unit Auxiliary Transformer (UAT) 141-1 differential relay sensing circuit testing was marked as “not applicable,” which indicates that testing was not performed when initially scheduled. The implementation procedure at Byron Station requires sensing circuit testing for the Protection System to be performed once every refueling cycle (typically every 18 months). However, Exelon Nuclear’s procedure permits an extension of that interval by processing a deferral when based on documented justification (e.g., for personnel safety reasons). In this case, the procedure requires the station to generate an “Issue Report” to document that the sensing circuit testing could not be performed and to track the incomplete portion of the testing to ensure completion at a later date within the interval or to process a deferral as necessary. The entity should have generated an Issue Report to document that, on the scheduled day of the testing, the sensing circuit testing could not be performed due to the electrical line-up (i.e., the circuit was energized and therefore due to safety concerns the testing could not be executed). The Issue Report, if written, would have tracked either rescheduling the testing within the defined testing interval or initiating a deferral of the testing per the PRC-005-1.1b program.

In this case, Byron Station did not generate an Issue Report as required per Exelon Nuclear’s procedure. (If a deferral had been processed, the incomplete testing would have been justified based on the electrical line-up and the safety concerns listed above.) As such, the testing was not rescheduled and a deferral was not processed.

After discovering the issue at Byron Station Unit 1, Exelon Nuclear continued performing its PRC-005 extent of condition review and identified the following additional instances when testing was not completed at eight additional nuclear units in RF (at the time of the extent of condition review, Exelon Nuclear had 18 nuclear units under the NERC Registration (NRC00778) in the RF Region):

(a) Byron Station (Unit 1) (i) UAT 141-2 CTs associated with the Differential Relay (2015 Refueling Outage (RFO)) were not tested (12 Current Transformers (CTs) - CT testing was not completed due to personnel safety concerns, but an Issue Report was not generated. (ii) UAT 141-1 CTs associated with the Differential Relay (2017 RFO) were not tested (12 CTs) due to personnel safety concerns, but an Issue Report was not generated. (iii) UAT 141-2 CTs associated with the Differential Relay (2017 RFO) were not tested (12 CTs) due to personnel safety concerns, but an Issue Report was not generated.

(b) Dresden (Units 2 and 3) (i) Six instances of missed sensing device (CTs) testing associated with auxiliary transformers due to not using a tracking mechanism to reschedule the testing or process a deferral. (ii) One instance of missed sensing device (CT) testing associated with generator protection due to procedure step omission. (iii) One instance of missed DC circuitry trip testing due to procedure step omission.

(c) Three Mile Island (Unit 1) (Exelon Nuclear permanently shut down Three Mile Island Unit 1 on September 20, 2019 and removed that unit from the NERC Registration for Exelon Nuclear (NRC00778) on October 11, 2019. The shutdown of this unit mitigates the issue identified at Three Mile Island Unit 1.) (i) Testing of the DC circuit paths for the main generator output breakers’ (GB1-02 and GB1-12) failure scheme did not include the wiring continuity from one output breaker’s failure lockout contacts to the primary and back-up trip coils of the other output breaker due to unclear and ineffective testing procedures. (The purpose of the breaker failure scheme is to trip all surrounding breakers should a breaker fail to open due to a fault somewhere in the system or due to a fault with the breaker itself which still allows current flow.)

(d) LaSalle Station (Units 1 and 2) (i) Two instances where relays were not functionally tested due to an omission of a procedure step. (ii) Four instances of missed DC circuitry testing due to an omission of a procedure step. (iii) Missed sensing device testing on four Main Power Transformer (MPTs) high voltage neutral CTs and CTs providing input to Auxiliary Transformers (SAT and UAT) differential current protective relays due to an omission of a procedure step.

(e) Oyster Creek (Exelon Nuclear permanently shut down Oyster Creek on September 17, 2018 and removed that unit from NERC Registration for Exelon Nuclear (NCR00778) on November 16, 2018. The shutdown of this unit mitigates the issue identified at Oyster Creek.) (i) One protective relay function of the Digital Protective Relay System “A” (DPRS-A) was not specifically tested during performance of the maintenance activity due to unclear and ineffective testing procedures. The protective function is the Accidental Energization (50AE) microprocessor protective relay.

(f) Limerick Generation Station (Units 1 and 2) (i) Power load unbalance relays 86-RLY-386-PLUA and 86-RLY-386-PLUB for both units were not specifically tested during performance of the maintenance activity prior to 2014 (Unit 1) and 2015 (Unit 2) due to unclear and ineffective testing procedures. The Limerick review identified that prior to a modification being installed in 2014 (Unit 1) and 2015 (Unit 2) no records could be identified clearly documenting that these power load unbalance relays picked up at appropriate electrical input levels.

ReliabilityFirst Corporation (ReliabilityFirst) Settlement Agreement (Neither Admits nor Denies) O&P
ReliabilityFirst Corporation (ReliabilityFirst) Settlement Agreement (Neither Admits nor Denies) O&P

Exelon Generation Company, LLC - Exelon Nuclear - NCR00778 NOC – 2670

Last Updated 04/30/2020

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<td>12/18/2019 (Mitigation Plan completion)</td>
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<td>12/18/2019</td>
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RF determined that this violation involves the management practices of work management and verification. RF considers Exelon Nuclear’s work procedures for maintaining and testing Protection System devices to be complicated and finds that these complicated work procedures led to missed or overdue maintenance and testing. RF identified those complicated and unclear work procedures as the root cause of this violation. Exelon Nuclear also did not have an effective verification control in place to ensure that all maintenance and testing for Protection System devices was timely and properly completed and documented.

Risk Assessment

This violation posed a moderate 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 violation is that not timely maintaining and testing Protection System devices could negatively impact the BPS by, for example, causing the unit to trip. The risk is not minimal because of the long multiyear duration of this violation and Exelon Nuclear’s compliance history with PRC-005-6 percentage implementation.

Exelon Nuclear timely completed all relay calibrations and associated sensing device testing for the above listed relays per its PRC-005-1.1b program. Lastly, during the violation, there were no internal transformer faults or fault conditions on any associated wiring that would have challenged the function of the differential circuit.

Mitigation

Exelon Nuclear remediated all of the instances described above in (a) through (f) by completing all required testing for all instances of missed testing identified by the extent of condition through a phased testing approach based on individual Unit refueling outage schedules.

To prevent recurrence, Exelon Nuclear performed the following actions:

1) conducted a two-day workshop with each station to present lessons learned and provide instructions to the stations on how to perform 100% review activities in a consistent manner;
2) conducted a management briefing and engagement presentation;
3) completed a 100% review of PRC-005 activities for protective relays, sensing devices, DC circuity, and communication systems across the fleet including reporting to RF any instances of potential non-compliance identified. (Exelon Nuclear performed an extensive review across its fleet that includes 100% review of the implementing documents that identify the maintenance activities for the testing required under PRC-005 (all versions). The review also included 100% verification of the last two completed maintenance activity records to ensure all components under the scope of PRC-005 were tested and activities completed in accordance with the applicable PRC-005 maintenance and testing program (PRC-005-1.1b and/or PRC-005-2/6). These reviews included an independent 100% verification by a separate individual. In addition, Exelon Nuclear is implementing proactive quarterly reporting. The actions associated with 100% verification of scope and implementing documents together with proactive reporting will reduce the probability of any further violations of PRC-005-1.1b or PRC-005-6 in the future. For each of the instances associated with missed testing of Sensing Circuits, performing the requirements of PRC-005-6 Table 1-3 will supersede the PRC-005-1.1b testing at issue (e.g., lamping) and therefore reduces the likelihood of a repeat violation.);
4) generated tracking items for fleet-wide Engineering NERC reporting to include verification and status of PRC-005 maintenance and testing activities for protective relays, sensing devices, DC circuity and communication systems and status of PRC-005-6 percentage implementation.

Other Factors

RF considered that Exelon Nuclear self-reported this violation and awarded some mitigating credit for self-reporting.

RF reviewed the entity’s internal compliance program (ICP) and determined it to be a neutral factor in the penalty determination.

RF considered Exelon Nuclear’s compliance history and determined there is a prior relevant instance of noncompliance in RF and RF considered that prior noncompliance to be an aggravating factor in the penalty determination.

As a non-monetary sanction, ReliabilityFirst and NPCC will conduct a spot check of Exelon Nuclear in the summer of 2021 to evaluate Exelon Nuclear’s ongoing compliance with PRC-005-6 R2.
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, alleged, or confirmed violation.)

On June 29, 2017, PGE submitted Self-Reports stating, as Balancing Authority (BA), it was in violation of COM-002-4 R5.

On December 8, 2016, one of PGE’s generation facilities tripped offline, losing approximately 180 MW of generation. At 4:33 PM, the BA Operator notified PGE’s Reliability Coordinator (RC) that PGE had insufficient generation to maintain its reserves and requested an Energy Emergency Alert (EEA), which the RC declared at 4:34 PM as an EEA1, and then escalated to EEA2 at 4:39 PM. PGE then obtained assistance from its neighboring entities and was able to recover its reserves. At 5:11 PM, the RC removed all EEA1s for PGE. Later, PGE evaluated the receiving and issuing of oral two-party, person-to-person Operating Instructions before, during and after the time of the EEA. It found the following calls were not issued or received, per the Standard Requirements:

a. On December 8, 2016 at 3:45 PM, PGE’s BA Operator contacted one of its generation facilities and issued an Operating Instruction to set the plant at its base rate. The plant Operator did not repeat the Operating Instruction, and the BA Operator did not request that he do so or reissue the Operating Instruction, as required by COM-002-4 R5.

b. At 4:21 PM the same day, the BA Operator contacted another generation facility and requested that the Operator increase the plant’s output level to the highest extent that was reasonably possible. The plant Operator did not repeat the Operating Instruction, and the BA Operator did not request that he do so or reissue the Operating Instruction, as required by COM-002-4 R5.

c. At 4:50 PM, when the BA Operator contacted the generation facility that had tripped offline and issued an Operating Instruction to return the steam turbine to service. The plant Operator did not repeat the Operating Instruction, and the BA Operator did not request that he do so or reissue the Operating Instruction, as required by COM-002-4 R5.

d. At 4:51 PM, when the BA Operator contacted another generation facility and issued an Operating Instruction to not set the output level of the plant to a level that could negatively affect the plant’s output. The plant Operator did repeat the Operating Instruction, but the BA Operator did not confirm that it was correct, as required by COM-002-4 R5.

e. During another call also at 4:51 PM, the BA Operator contacted another generation facility and issued an Operating Instruction to set the plant output to a reasonable level, according to the Operator. The plant Operator did not repeat the Operating Instruction, and the BA Operator did not request that he do so or reissue the Operating Instruction, as required by COM-002-4 R5.

The root cause of the issues associated with COM-002-4 R5 was attributed to the lack of follow-up training for the System Operators to reinforce the proper method to perform three-way communications. This issue began on December 8, 2016, when PGE did not confirm the receiver’s response nor repeat the Operating Instruction, related to five calls during an EEA and ended on December 8, 2016 when the EEA ended.

Risk Assessment

This violation posed a moderate risk and did not pose a serious and substantial risk to the reliability of the Bulk Power System (BPS). In these instances, PGE failed, on five occasions, to both confirm the receiver’s response if the repeated information is correct and repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, as required by COM-002-4 R5. Failure to ensure the Operating Instructions were confirmed and repeated could lead to a misunderstanding of the actions to be performed. Approximately 2,000 MW of generation within PGE’s BA footprint could have been impacted and further could have impacted the Western Interconnection during the EEA.

However, as compensation, PGE participated in a regional reserve sharing group during the EEA that it was able to utilize to receive assistance. In addition, audio recordings between PGE and the RC showed that no load had been shed during the EEA. Even though the series of communications occurred before and during the EEA, WECC confirmed there was no confusion between the issuers and the receivers of the Operating Instructions, reducing the risk of miscommunications or the carrying out of inappropriate instructions. Furthermore, there were no Operating Instructions issued by the RC to the BA Operators at PGE.

Mitigation

To mitigate this violation, PGE:

1) updated its internal procedure to clarify what constitutes an Operating Instruction and the required response. The internal procedure is required to be reviewed and signed at the beginning of every shift;
2) issued a reminder email from PGE’s responsible Vice President to remind employees of their obligation to comply with the Standards, which was circulated by the plant operators who were required to review and sign;
3) added a more detailed description of Operating Instructions and three-way communication to the annual NERC Reliability Standards training that all plant operators are required to complete;
4) added a question about proper performance of three-way communication as part of the BA Operator quarterly performance evaluation;
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<td>WECC2017017872</td>
<td>COM-002-4</td>
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<td>12/8/2016 (when PGE did not confirm the receiver’s response nor repeat the Operating Instruction, related to five calls during an EEA)</td>
<td>12/8/2016 (when the EEA ended)</td>
<td>Self-Report</td>
<td>6/15/2017</td>
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5) sent an email to all BA operators asking them to describe what constitutes an Operating Instruction to reaffirm understanding of an Operating Instruction; and
6) implemented a plan to continue spot checking BA Operator recorded phone calls to ensure that proper communication is being used for issuing Operating Instructions.

Other Factors

WECC reviewed PGE’s internal compliance program (ICP) and considered it to be a neutral factor in the penalty determination. Although PGE does have a documented ICP, WECC determined that it was not effective in detecting or preventing multiple instances of noncompliance with the violations in this disposition.

WECC considered PGE’s compliance history with COM-002-4 and determined there were no relevant instances of noncompliance.

WECC applied mitigation credit in the penalty determination because PGE: (i) was cooperative throughout the enforcement process, (ii) admitted to the violation, and (iii) agreed to settle the violation.
### NERC Violation ID

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<tr>
<td>WECC2017017873</td>
<td>COM-002-4</td>
<td>R6</td>
<td>High</td>
<td>Moderate</td>
<td>12/8/2016 (when PGE did not confirm the receiver’s response nor repeat the Operating Instruction, related to four calls during an EEA)</td>
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### 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, 2017, PGE submitted Self-Reports stating, as a Generation Operator (GOP) it was in violation of COM-002-4 R6.

On December 8, 2016, one of PGE’s generation Facilities tripped off line, losing approximately 180 MW of generation. At 4:33 PM, the BA Operator notified PGE’s Reliability Coordinator (RC) that PGE had insufficient generation to maintain its reserves and requested an Energy Emergency Alert (EEA), which the RC declared at 4:34 PM as an EEA1, and then escalated to EEA2 at 4:39 PM. PGE then obtained assistance from its neighboring entities and was able to recover its reserves. At 5:11 PM, the RC removed all EEA’s for PGE. Later, PGE evaluated the receiving and issuing of oral two-party, person-to-person Operating Instructions before, during, and after the time of the EEA. It found the following calls were not issued or received, per the Standard Requirements:

a. On December 8, 2016 at 4:21 PM, the BA Operator contacted one of its generation facilities and issued an Operating Instruction to set the plant at its base rate. The plant Operator did not repeat the Operating Instruction, and the BA Operator did not request that he do so or reissue the Operating Instruction, as required by COM-002-4 R6.

b. At 4:35 PM the same day, the BA Operator contacted another generation facility and requested that the Operator increase the plant’s output level to the highest extent that was reasonably possible. The plant Operator did not repeat the Operating Instruction, and the BA Operator did not request that he do so or reissue the Operating Instruction, as required by COM-002-4 R6.

c. At 4:50 PM, when the BA Operator contacted the generation facility that had tripped offline and issued an Operating Instruction to return the steam turbine to service. The plant Operator did not repeat the Operating Instruction, and the BA Operator did not request that he do so or reissue the Operating Instruction, as required by COM-002-4 R6.

d. During another call also at 4:51 PM, the BA Operator contacted another generation facility and issued an Operating Instruction to set the plant output to a reasonable level, according to the Operator. The plant Operator did not repeat the Operating Instruction, and the BA Operator did not request that he do so or reissue the Operating Instruction, as required by COM-002-4 R6.

The root cause of the issues associated with COM-002-4 R6 was attributed to the lack of follow-up training for the System Operators to reinforce the proper communication of Operating Instructions before, during, and after the time of the EEA. The plant Operator did not repeat the information is correct and repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, as required by COM-002-4 R6.

Failure to ensure the Operating Instructions were confirmed and repeated could lead to a misunderstanding of the actions to be performed. Approximately 2,000 MW of generation within PGE’s BA footprint could have been impacted and further could have impacted the Western Interconnection during the EEA.

However, as compensation, PGE participated in a regional reserve sharing group during the EEA that it was able to utilize to receive assistance. In addition, audio recordings between PGE and the RC showed that no load had been shed during the EEA. Even though the series of communications occurred before and during the EEA, WECC confirmed there was no confusion between the issuers and the receivers of the Operating Instructions, reducing the risk of miscommunications or the carrying out of inappropriate instructions. Furthermore, there were no Operating Instructions issued by the RC to the BA Operators at PGE.

### Risk Assessment

This violation posed a moderate risk and did not pose a serious and substantial risk to the reliability of the BPS. In these instances, PGE failed, on four occasions, to both confirm the receiver’s response if the repeated information is correct and repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, as required by COM-002-4 R6. Failure to ensure the Operating Instructions were confirmed and repeated could lead to a misunderstanding of the actions to be performed. Approximately 2,000 MW of generation within PGE’s BA footprint could have been impacted and further could have impacted the Western Interconnection during the EEA.

### Mitigation

To mitigate this violation, PGE:

1) updated its internal procedure to clarify what constitutes an Operating Instruction and the required response. The internal procedure is required to be reviewed and signed at the beginning of every shift;

2) issued a reminder email from PGE’s responsible Vice President to remind employees of their obligation to comply with the Standards, which was circulated by the plant operators who were required to review and sign;

3) added a more detailed description of Operating Instructions and three-way communication to the annual NERC Reliability Standards training that all plant operators are required to complete;

4) added a question about proper performance of three-way communication as part of the BA Operator quarterly performance evaluation;

5) sent an email to all BA operators asking them to describe what constitutes an Operating Instruction to reaffirm understanding of an Operating Instruction; and

6) implemented a plan to continue spot checking BA Operator recorded phone calls to ensure that proper communication is being used for issuing Operating Instructions.

### Other Factors

WECC reviewed PGE’s internal compliance program (ICP) and considered it to be a neutral factor in the penalty determination. Although PGE does have a documented ICP, WECC determined that it was not effective in detecting or preventing multiple instances of noncompliance with the violations in this disposition.
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<td>Self-Report</td>
<td>6/15/2017</td>
<td>8/2/2018</td>
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WECC considered PGE’s compliance history with COM-002-4 and determined there were no relevant instances of noncompliance.

WECC applied mitigation credit in the penalty determination because PGE: (i) was cooperative throughout the enforcement process, (ii) admitted to the violation, and (iii) agreed to settle the violation.
For Plant 1: seven of the 10 instances identified at the WECC Compliance Audit were associated with the DSTATCOM of a wind generating facility with a nameplate capacity rating of 518 MVA. In these instances, the TOP was not notified of the status of the DSTATCOM. In seven of the 10 instances, the TOP was not notified of the DSTATCOM alternative voltage controlling device status change. This could have reasonably resulted in the TOP not including the correct status of the voltage controlling device for this generating facility in its Operating Plan and Real-Time Assessment.

For Plant 2: one of the 10 instances identified at the WECC Compliance Audit were associated with a PSS at a hydro generating facility with a nameplate capacity rating of 108 MVA. This facility has three generating units. In this instance, the TOP was not notified of the restoration of a PSS at this facility. This could have reasonably resulted in the TOP not including the correct PSS status for the generating unit in its Operating Plan and Real-Time Assessment.

For Plant 3: two of the 10 instances identified at the WECC Compliance Audit were associated with a PSS at a hydro generating facility with a nameplate capacity rating of 413 MVA. This facility has three generating units. In this instance, the TOP was not notified of the restoration of a PSS at this facility. This could have reasonably resulted in the TOP not including the correct PSS status for the generating unit in its Operating Plan and Real-Time Assessment.

These instances began on December 20, 2013, when PGE did not report the status change of its wind farm DSTATCOM alternative voltage controlling device to its TOP, and ended on February 22, 2017, when PGE provided its TOP with the correct information about the status change of the alternative voltage controlling device, for a total of 12 instances over 1,161 days of noncompliance.

On June 30, 2017, PGE submitted a Self-Report stating, as a GOP, it was in violation of VAR-002-4 R3. In addition, during a Compliance Audit conducted July 10, 2017 to July 21, 2017, WECC determined PGE had additional instances of noncompliance which changed the start date to predate the current version of the Standard and therefore the violation is of VAR-002-2b R3.

Per PGE's self-report, on December 14, 2016, PGE's wind farm plant technician interpreted several distribution static synchronous compensator (DSTATCOM) equipment alarms at the wind farm to indicate a loss of reactive power capability. Understanding DSTATCOM equipment alarms to be a reportable change of a voltage controlling device, PGE's wind plant technician immediately called PGE's System Control Center (SCC) to report the event. PGE's SCC then notified its Transmission Operator (TOP) that the DSTATCOM was out of service with no expected time of return. However, the DSTATCOM equipment alarms only indicated that individual +/-1 MVAR inverters were off-line and that the status of the wind farm DSTATCOM alternative voltage controlling device was out of service and that it had already notified its TOP of the status change of the wind farm DSTATCOM alternative voltage controlling device on December 14, 2016.

Later, on January 10, 2017 at 8:29 AM, one of PGE's wind farm plant technicians contacted its SCC's Transmission and Distribution (T&D) dispatcher and required that three breakers be opened so that the plant staff could replace nine individual inverter trays related to the December 14, 2016 DSTATCOM equipment alarms. However, PGE did not notify its TOP of the status change in the alternative voltage controlling device because it assumed that the wind farm DSTATCOM alternative voltage controlling device was out of service and that it had already notified its TOP of the status change of the wind farm DSTATCOM alternative voltage controlling device.

On January 12, 2017, at 3:32 PM, the plant technician contacted the SCC's T&D Dispatcher to request that the breakers be closed to return the wind farm DSTATCOM alternative voltage controlling device to service. However, PGE did not notify its TOP of the wind farm DSTATCOM alternative voltage controlling device status change.

In both instances, PGE did not notify the TOP of the wind farm DSTATCOM alternative voltage controlling device status change within the 30 minutes of such change. However, PGE's TOP was provided with the correct information about the status change of the wind farm DSTATCOM alternative voltage controlling device on February 22, 2017. The root cause of these instances was attributed to less than adequate procedures that were not well-defined, understood, or enforced by management causing the plant technician to incorrectly interpret the alternative voltage controlling device to be offline; further, resulting in PGE not notifying its TOP of the alternative voltage controlling device status change.

The WECC Compliance Audit identified 10 additional instances between December 30, 2013 and October 19, 2015 for which PGE was unable to document that it had notified its TOP of changes in status of the wind farm's DSTATCOM alternative voltage controlling device within the required timeframe. PGE was unable to show that it had notified its TOP of the restoration of power system stabilizer (PSS) operability after scheduled PSS outages at a second plant on October 27, 2015 and at a third plant on January 28, 2014 and February 12, 2015. The root cause for these instances of noncompliance was insufficient staff training for reporting the notifications to its TOP.

For Plant 1: seven of the 10 instances identified at the WECC Compliance Audit were associated with the DSTATCOM of a wind generating facility with a nameplate capacity rating of 518 MVA. In these instances, the TOP was not notified of the status of the DSTATCOM. In seven of the 10 instances, the TOP was not notified of the DSTATCOM being returned to service. This could have reasonably resulted in the TOP not including the correct status of the voltage controlling device for this generating facility in its Operating Plan and Real-Time Assessment.

For Plant 2: one of the 10 instances identified at the WECC Compliance Audit were associated with a PSS at a hydro generating facility with a nameplate capacity rating of 108 MVA. This facility has three generating units. In this instance, the TOP was not notified of the restoration of a PSS at this facility. This could have reasonably resulted in the TOP not including the correct PSS status for the generating unit in its Operating Plan and Real-Time Assessment.

For Plant 3: two of the 10 instances identified at the WECC Compliance Audit were associated with a PSS at a hydro generating facility with a nameplate capacity rating of 413 MVA. This facility has three generating units. In this instance the TOP was not notified of the restoration of a PSS at this facility. This could have reasonably resulted in the TOP not including the correct PSS status for the generating unit in its Operating Plan and Real-Time Assessment.

These instances began on December 20, 2013, when PGE did not report the status change of its wind farm DSTATCOM alternative voltage controlling device to its TOP, and ended on February 22, 2017, when PGE provided its TOP with the correct information about the status change of the alternative voltage controlling device, for a total of 12 instances over 1,161 days of noncompliance.

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<td>Violation Start Date</td>
<td>Violation End Date</td>
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<td>WECC2017017874</td>
<td>VAR-002-2b</td>
<td>R3</td>
<td>Medium</td>
<td>Severe</td>
<td>12/20/2013 (when PGE did not report the status change of its wind farm DSTATCOM alternative voltage controlling device to its TOP)</td>
<td>2/22/2017 (when PGE provided its TOP with the correct information about the status change of the alternative voltage controlling device)</td>
<td>Self-Report</td>
<td>10/31/2018</td>
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</table>

**Risk Assessment**

This violation posed a minimal risk and did not pose a serious and substantial risk to the reliability of the BPS. In these instances, PGE failed to notify its associated TOP 12 times of a status change on voltage controlling device within 30 minutes of the change, as required by VAR-002-4 R3. As compensation, there was no expected loss of generation, load, or transmission elements, for a failure to report the status of the voltage controlling device. Additionally, none of the 12 instances occurred simultaneously. For all three affected plants, a majority of the 12 instances were for failing to notify the TOP of the PSS or voltage control device being put back into service. This fact reduces the impact of potential harm because the device was back in service and operating as expected instead of a more serious condition, such as the TOP not being aware that the device was out of service and would therefore need to take manual action to compensate for the devices. The inverter trays associated with the DSTATCOM at Plant 1 only resulted in a 1 MVAR loss of reactive power capability. The loss of 1 MVAR of reactive power capability would have had minimal, if any, impact on the BPS. Additionally, for Plants 2 and 3, which had PSS, the generating Facilities were small and located in fairly remote areas, thus reducing the impact they could have had for damping oscillations on the system.

**Mitigation**

To mitigate this violation, PGE:

1. submitted correct status information for the AVR, PSS, or alternative voltage controlling device that interconnect with their TOP in real-time via ICCP for generating units in the instant violation;
2. automated notifications of AVR and PSS status via EMS for certain generating units to the System Control Center (SCC). This will allow the AVR/PSS status points to be transmitted in real-time via remote terminal unit (RTU) to the SCC Energy Management System (EMS). The EMS alarms will alert the System Operators when there are status changes;
3. provided combined real-time AVR/PSS status indication via EMS to the GOP and TOP System Control Center for all generating units;
4. revised generating facility compliance procedures to reflect that plant operators need to notify the SCC of status changes by phone in the event of an RTU failure. The SCC procedures were revised to instruct System Operators to notify plant operators of any RTU failures and to notify the TOP by phone of any reactive power status changes in the event of an ICCP failure; and
5. delivered operator training on the new processes to both plant operators and SCC System Operators once the revised procedures are in place.

**Other Factors**

WECC reviewed PGE's internal compliance program (ICP) and considered it to be a neutral factor in the penalty determination. Although PGE does have a documented ICP, WECC determined that it was not effective in detecting or preventing multiple instances of noncompliance with the violations in this disposition.

WECC considered PGE's VAR-002 compliance history to be an aggravating factor in the penalty determination and disposition track.

WECC applied mitigation credit in the penalty determination because PGE: (i) was cooperative throughout the enforcement process, (ii) admitted to the violation, and (iii) agreed to settle the violation.

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 6, 2017, PNM submitted a Self-Report stating, as a Transmission Operator, it had a potential noncompliance with TOP-002-2.1b R19.

On September 12, 2016 at 11:30 AM, a circuit breaker at one of PNM’s 345 kV switching stations faulted internally, due to a possible insulation failure internal to the breaker. The fault was within two separate zones of protection, one generator step-up transformer and one bus. However, only one of the protection devices operated, as the generator step-up transformer differential protection detected the fault and tripped open the 345 kV lines breakers to clear the fault. The second protective device did not operate due to a previously undetected short circuit in the associated current transformer (CT) cabling. As a result, the next line of protective devices operated to clear the fault for the elements that terminate at the 345 kV switching station, which caused the protective devices to trip locally or at the other end of the lines to clear the fault. The operation of the next line protection devices caused eight Bulk Electric System (BES) transmission lines and three generation units to trip off-line, creating an N-8 contingency.

PNM System Operators assumed the custom calculation for one of its Remedial Action Schemes (RAS) would add the RAS contribution to the manually inputted SOL. The custom calculation did not automatically add the RAS contribution, resulting in the SOL being understated by approximately 500 MW. The cause of the error in the custom calculation was that the Energy Management System (EMS) calculation had been updated by the System Operator and was not checked by anyone else. The actual SOL should have been 800 MW + 500 MW (Import Contingency Load Shedding Scheme Remedial Action Scheme contribution in place at the time of the event), equaling 1,300 MW. As a result, the incorrect value was transmitted to the Reliability Coordinator (RC) as a valid SOL. PNM’s Operators were operating above the erroneous 800 MW SOL at the time, and as a result of this error, the RC directed PNM to shed firm load in order to return the system to within what it thought was a valid SOL. PNM followed the directive and shed 100 MW of load at 12:24 PM to achieve the SOL without the RAS contribution, which returned the Facility to its correct SOL and the system to its “known” operating state and acceptable system operating limits. The root cause of the violation was attributed to a lack of controls for the System Operator in the various tasks he was performing, including manually entering the EMS custom calculations and then having the same System Operator checking the calculations. In addition, there was an influx of concurrent post-outage activity being managed. Because the System Operator did not immediately recognize the failure of the EMS custom calculation, he did not communicate the error to the RC in order to stop the shed load directive.

The violation began on September 12, 2016, when PNM’s EMS failed to include the contribution of the ICLSS RAS into the SOL and ended on September 13, 2016, when PNM updated its custom calculation formula in its EMS model to include the ICLSS RAS with the SOL.

Risk Assessment

WECC determined these violations (WECC2017016935 and WECC2017016936) posed a moderate risk and did not pose a serious and substantial risk to the reliability of the Bulk Power System (BPS). In this instance, PNM failed to maintain accurate computer models utilized for analyzing and planning system operations when its EMS failed to include the contribution of a RAS to an SOL in a custom calculation entered into the EMS during a contingency, as required by TOP-002-2.1b R19. The WECC Major Transfer Path was incorrectly showing an exceedance of the SOLs, though there was not an SOL exceedance, which led the RC to inaccurately issue the directive to shed the load. This load shed elevated the risk of the violation and increased the assessed penalty.

However, as compensation, PNM invoked contingency reserves from the Reserve Sharing Group, started all available load-side generation, and acquired emergency assistance. Lastly, PNM’s protection system devices successfully acted to clear the faulted equipment, and PNM did not operate above SOLs during the event.

Mitigation

To mitigate this violation, PNM:

1) corrected the custom calculation to include the RAS available load when it is manually substituted into the EMS;
2) hosted face-to-face meetings with the RC to address communications between the work groups; and
3) instituted internal controls to prevent or minimize the possibility of recurrence including developing lessons learned for System Operators to address contributing factors which caused the System Operator not to immediately realize the SOL mistake including:
   i. developed lessons learned and best practice approaches for restoration from large outages and captured them in an updated Transmission Procedure; and
   ii. performed training with key personnel on lessons learned, best practice, and the updated Transmission Procedure.
WECC reviewed PNM’s internal compliance program (ICP) and considered it to be a mitigating factor in the penalty determination. PNM has an ICP which demonstrates a strong culture of compliance. PNM’s ICP has a well-established program including systematic preventive measures, operational level procedures, internal controls, and corporate policies.

WECC considered “above and beyond” actions and investments made by PNM in an effort to prevent recurrence of this issue and proactively address and reduce reliability and cyber security risk due to similar issues. PNM has initiated a System-Wide Transmission Protection Standardization and Upgrade Project in a multi-year effort that officially began in 2018 and is expected to be completed in 2023 at a total cost of over $50M. This significant project addresses issues associated with PNM’s aging and non-standardized transmission protection system that not only enhances the management and security of the new CIP protection system devices, but the overall reliability of the system and associated Operations and Planning compliance. This above and beyond action is effectively a redesign and deployment of PNM’s protection system which is well beyond what would be considered a typical action of a similarly situated utility. The project was not undertaken as the result of a mitigation plan. Rather, it was the result of PNM’s systematic, post-event root cause analysis and corrective action planning program.

WECC considered PNM’s TOP-002-2.1b R19 compliance history. WECC determined that NERC Violation ID WECC200810312 should not serve as a basis for aggravating the penalty because the cause and the circumstance of the previous violation is different than the current issue.

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 6, 2017, PNM submitted a Self-Report stating, as a Transmission Operator, it had a potential noncompliance with TOP-004-2 R4.

On September 12, 2016 at 11:30 AM, a circuit breaker at one of PNM’s 345 kV switching stations faulted internally, due to a possible insulation failure internal to the breaker. The fault was within two separate zones of protection, one generator step-up transformer and one bus. However, only one of the protection devices operated, as the generator step-up transformer differential protection detected the fault and tripped open the 345 kV lines breakers to clear the fault. The second protective device did not operate due to a previously undetected short circuit in the associated current transformer (CT) cabling. As a result, the next line of protective devices operated to clear the fault for the elements that terminate at the 345 kV switching station, which caused the protective devices to trip locally or at the other end of the lines to clear the fault. The operation of the next line protection devices caused eight Bulk Electric System (BES) transmission lines and three generation units to trip off-line, creating an N-8 contingency.

PNM System Operators made multiple attempts to restore two specific 345 kV lines, which would have returned PNM’s system to a "known" operating state. However, efforts to restore those lines over 20-30 minutes proved unsuccessful due to the internally faulted breaker at the 345 kV Station. In tandem with System Operators’ efforts to restore the two lines, PNM Operations Engineers manually calculated a new “known” System Operating Limit (SOL) for the N-8 condition, and at approximately 12:08 PM the new SOL was substituted into the Energy Management System (EMS), approximately 38 minutes after the initial disturbance began.

PNM System Operators assumed the custom calculation for one of its Remedial Action Schemes (RAS) would add the RAS contribution to the manually inputted SOL. The custom calculation did not automatically add the RAS contribution, resulting in the SOL being understated by approximately 500 MW. The actual SOL should have been 800 MW + 500 MW (ICLSS RAS contribution in place at the time of the event), equaling 1,300 MW.

As a result, the incorrect value was transmitted to the Reliability Coordinator (RC) as a valid SOL. PNM’s Operators were operating above the erroneous 800 MW SOL at the time, and as a result of this error, the RC directed PNM to shed firm load in order to return the system to within what it thought was a valid SOL. PNM followed the directive and shed 100 MW of load at 12:24 PM to achieve the SOL without the RAS contribution, which returned the Facility to its correct SOL and the system to its “known” operating state and acceptable system operating limits.

The TOP-004-2 R4 violation began on September 12, 2016 at 12:01 PM, 30 minutes after the contingency N-8 event began and PNM had not yet restored the system and ended on September 12, 2016 at 12:24 PM when it restored the system, for a total of 24 minutes.

The root cause of the TOP-004-2 R4 violation was attributed to PNM’s topology processor providing an incorrect status indication regarding the bus, due to an incorrect breaker indication which prevented the System Operator from being able to identify where the fault occurred in a timely manner, leading to the re-energization of the faulted breaker in an attempt to restore the system to a known operating state.

Risk Assessment

WECC determined these violations (WECC2017016935 and WECC2017016936) posed a moderate risk and did not pose a serious and substantial risk to the reliability of the Bulk Power System (BPS). In these instances, PNM failed to restore operations to respect proven reliable power system limits within 30 minutes during an unknown operating state, when the N-8 contingency event began and PNM had not yet restored the system, as required by TOP-004-2 R4. The WECC Major Transfer Path was incorrectly showing an exceedance of the SOLs, though there was not an SOL exceedance, which led the RC to inaccurately issue the directive to shed the load. This load shed elevated the risk of the violation and increased the assessed penalty.

However, as compensation, PNM invoked contingency reserves from the Reserve Sharing Group, started all available load-side generation, and acquired emergency assistance. Lastly, PNM’s protection system devices successfully acted to clear the faulted equipment and PNM did not operate above SOLs during the event.

Mitigation

To mitigate this violation, PNM has:

1) returned the system to within “known” operating limits;
2) instituted internal controls to prevent and detect future issues including:
   i. developed lessons learned and best practice approaches for restoration from large outages and captured them in an updated Transmission Procedure;
   ii. performed training with key personnel on lessons learned, best practice and the updated Transmission Procedure, the causal factors of the instant issue and Human Performance Considerations. A procedure based on the lessons learned has been integrated in the initial training program required for all System Operators, and the lessons learned from the related event have been added to the annual protective relay training to ensure that operators are aware of the lessons learned from this event;
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3) pursued work with the EMS vendor to improve topology processing issues and improve situational awareness, specifically PNM:
   i. implemented local logic in an effort to improve situational awareness;
   ii. added the logic to the Energy Management System (EMS) for all remote terminal units (RTUs) such that a calculation detects when an RTU goes offline and it will flash a message to the Operator at the bus when the data was affected by going offline; and
4) created a breaker indicator alarm as an enhancement to its topology processor to improve PNM’s situational awareness.

Other Factors

WECC reviewed PNM’s internal compliance program (ICP) and considered it to be a mitigating factor in the penalty determination. PNM has an ICP which demonstrates a strong culture of compliance. PNM’s ICP has a well-established program including systematic preventive measures, operational level procedures, internal controls, and corporate policies.

WECC considered “above and beyond” actions and investments made by PNM in an effort to prevent recurrence of this issue and proactively address and reduce reliability and cyber security risk due to similar issues. PNM has initiated a System-Wide Transmission Protection Standardization and Upgrade Project in a multi-year effort that officially began in 2018 and is expected to be completed in 2023 at a total cost of over $50M. This significant project addresses issues associated with PNM’s aging and non-standardized transmission protection system that not only enhances the management and security of the new CIP protection system devices, but the overall reliability of the system and associated Operations and Planning compliance. This above and beyond action is effectively a redesign and deployment of PNM’s protection system which is well beyond what would be considered a typical action of a similarly situated utility. The project was not undertaken as the result of a mitigation plan. Rather, it was the result of PNM’s systematic, post-event root cause analysis and corrective action planning program.

WECC considered PNM’s compliance history and determined there were no relevant instances of noncompliance.
On October 26, 2016, PNM submitted a Self-Report stating, as a Generator Owner and Transmission Owner, it had a potential noncompliance with PRC-005-1.1b R2.

Specifically, PNM did not provide documentation for maintenance of its three valve-regulated lead-acid (VRLA) batteries, one vented-regulated lead-acid (VLA) battery, two transmission relays, eight battery chargers, and 155 instrument transformers within their maximum maintenance intervals defined in PNM’s Protection System Maintenance Program (PSMP), as required by PRC-005-1.1b R2. The root cause of the violation was attributed to ambiguous instructions related to documenting and retaining evidence of PSMP maintenance tasks. In addition, there was a lack of quality control or inspection of the protection system devices that required preventative maintenance. PNM’s PSMP during this time required visual inspections for the Protection System devices every four months, which are not required under the new version of the Standard. The missed maintenance activities for the 155 Instrument Transformers were missed visual inspections that would not have been required under PRC-005-6. In addition, the missed maintenance activities for the two transmission relays were four calendar-year requirements that, under PRC-005-6, would have only needed to be completed every six calendar years. The first Protection System device was not maintained starting January 1, 2015 and the last missing device was maintained on February 27, 2017.

PNM had weak preventative and detective controls. However, as compensation, PNM was following a stricter timeline for its maintenance and testing for its Protection System devices than is required by the current version of the Standard, reducing the risk by increasing the maintenance and testing activities. Specifically, the missed maintenance activities for the 155 Instrument Transformers were missed visual inspections that would not have been required under PRC-005-6. In addition, the missed maintenance activities for the two transmission relays mentioned above were four calendar-year requirements that, under the current version of the Standard, would have only needed to be completed every six calendar years.

WECC reviewed PNM’s internal compliance program (ICP) and considered it to be a mitigating factor in the penalty determination. PNM has an ICP which demonstrates a strong culture of compliance. PNM’s ICP has a well-established program including systematic preventive measures, operational level procedures, internal controls, and corporate policies.

WECC considered “above and beyond” actions and investments made by PNM in an effort to prevent recurrence of this issue and proactively address and reduce reliability and cyber security risk due to similar issues. PNM has initiated a System-Wide Transmission Protection Standardization and Upgrade Project in a multi-year effort that officially began in 2018 and is expected to be completed in 2023 at a total cost of over $50M. This significant project addresses issues associated with PNM’s aging and non-standardized transmission protection system that not only enhances the management and security of the new CIP protection system devices, but the overall reliability of the system and associated Operations and Planning compliance. This above and beyond action is effectively a redesign and deployment of PNM’s protection system which is well beyond what would be considered a typical action of a similarly situated utility. The project was not undertaken as the result of a mitigation plan. Rather, it was the result of PNM’s systematic, post-event root cause analysis and corrective action planning program.

WECC considered PNM’s PRC-005 compliance history in determining the penalty. WECC considered NERC Violation IDs: WECC2014013971, and WECC200810375 to be aggravating factors in the penalty determination.
On May 25, 2018, PNM submitted a Self-Report stating, as a Transmission Owner, it was in potential noncompliance with PRC-005-1.1b R2. PNM did not provide documentation of maintenance and testing for two microprocessor relays and one electromechanical relay at one substation with two 115 kV lines, within its PSMP. The microprocessor relay was not maintained according to its six-calendar-year interval with a one-year grace period, and the electromechanical relay was not maintained on a three-calendar-year interval with a one-year grace period. The two microprocessor relays were maintained in 2009 and were not maintained by the due date of December 31, 2015. The electromechanical relay was maintained in 2009 and was not maintained again by the due date of December 31, 2013. The root cause of the violation was attributed to a lack of internal controls to ensure accuracy. Specifically, the relays were not included in the prints and therefore the relay technician did not include them for testing and maintenance. This violation began on January 1, 2014, when PNM did not complete the required maintenance activities for two microprocessor relays and one electromechanical relays, and ended on March 15, 2018, when PNM performed maintenance on all the relays.

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, PNM failed to provide documentation for maintenance and testing for two microprocessor relays and one electromechanical relay at one substation with two 115 kV lines as part of its PSMP, as required by PRC-005-1.1b R2. However, as compensation, the two microprocessor relays serve as secondary (redundant) protection for two 115 kV lines that are not part of a WECC Major Transfer Path. Though a failure to maintain the microprocessor relay on the first 115 kV line could result in the trip of the 115 kV line, it would not result in a loss of load or system generation. In addition, if there were a failure of the second microprocessor relay in addition to the electromechanical relay on the second 115 kV line, it would result in a loss of less than 100 MW of load.

To mitigate this violation, PNM has:
1) completed the maintenance activities for two microprocessor relays and one electromechanical relay at one substation and two 115 kV lines;
2) updated prints to address lack of accurate protection system and controls drawings;
3) corrected errant Cascade entries;
4) established monthly meetings between Protection System and Controls and Technical Maintenance Management Department to discuss issues related to relays upgrades, maintenance evidence, change to existing set of relays, and Cascade updates;
5) developed and documented the processes for Maintenance Technicians, including contract labor;
6) developed and implemented training to all relevant personnel on the Maintenance Technicians process, focusing on the handoff between relay craft and other departments;
7) verified CIP device inventory matched with the protection system devices in Cascade;
8) completed listing individual relay records in Cascade and eliminated grouping of relays in Packages; this step included separation of 100% of all BES relay packages within Cascade; and
9) updated the protection and controls drawings for the protection system devices in scope.

WECC reviewed PNM’s internal compliance program (ICP) and considered it to be a mitigating factor in the penalty determination. PNM has an ICP which demonstrates a strong culture of compliance. PNM’s ICP has a well-established program including systematic preventive measures, operational level procedures, internal controls, and corporate policies.

WECC considered “above and beyond” actions and investments made by PNM in an effort to prevent recurrence of this issue and proactively address and reduce reliability and cyber security risk due to similar issues. PNM has initiated a System-Wide Transmission Protection Standardization and Upgrade Project in a multi-year effort that officially began in 2018 and is expected to be completed in 2023 at a total cost of over $50M. This significant project addresses issues associated with PNM’s aging and non-standardized transmission protection system that not only enhances the management and security of the new CIP protection system devices, but the overall reliability of the system and associated Operations and Planning compliance. This above and beyond action is effectively a redesign and deployment of PNM’s protection system which is well beyond what would be considered a typical action of a similarly situated utility. The project was not undertaken as the result of a mitigation plan. Rather, it was the result of PNM’s systematic, post-event root cause analysis and corrective action planning program.

WECC considered PNM’s PRC-005 compliance history in determining the penalty. WECC considered NERC Violation IDs: WECC2014013971, and WECC200810375 to be aggravating factors in the penalty determination.
**Bonneville Power Administration (BPA) – NCR05032**

**WECC Settlement Agreement O&P**

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<td>MOD-029-1a</td>
<td>R2, R2.6</td>
<td>Lower</td>
<td>Lower</td>
<td>5/15/2016 (when BPA did not correctly allocate the TTC for one ATC path)</td>
<td>5/15/2016 (when it corrected the TTC allocation for the ATC path)</td>
<td>Self-Report</td>
<td>8/31/2016</td>
<td>4/4/2017</td>
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**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 21, 2016 BPA submitted a Self-Report stating, as a Transmission Operator (TOP), it was in violation of MOD-029-1a R2, R2.6. Specifically, on May 15, 2016, BPA incorrectly allocated the Total Transmission Capability (TTC) for one Available Transmission Capability (ATC) path when incorporating an outage in the Western Interconnection. BPA had a contractual allocation agreement with another TOP that required the TTC to be shared pro-rata during an outage. However, BPA did not reduce the TTC for the ATC path, but instead took the entire reduction. According to the contractual allocation agreement, the entities were required to reduce pro-rata to account for the outage. BPA corrected the TTC allocation that same day. The root cause of this instance was attributed to the desk-level procedure not addressing governance of the allocation of the shared ownership in the ATC path. This violation began on May 15, 2016 when BPA did not correctly allocate the TTC for one ATC path, and ended on May 15, 2016 when it corrected the TTC allocation for the ATC path for a total of one day of noncompliance.

**Risk Assessment**

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, BPA failed to use the following process to determine TTC: where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path, as required by MOD-029-1a R2. In this instance, BPA did not reduce the TTC for the ATC path, instead it took the entire reduction. Such failure is a commercial operational issue and presents a negligible potential harm to the reliability of the BPS.

BPA implemented weak preventative controls to prevent the violation. As a compensation, MOD-029-2a is proposed for retirement due to its focus on commercial operations instead of the potential harm to the reliability of the BPS. In addition, the duration of the violation was one day, thus reducing the risk.

**Mitigation**

To mitigate this violation, BPA:

1. allocated the correct TTC;
2. conducted extensive training with staff on properly allocating TTCs in outage conditions across the ATC paths;
3. MOD-029-2a is proposed for retirement by NERC due to its emphasis on contractual agreements and minimal effects to reliability of the BPS;
4. tested different ways that real-timeSchedulers can access the screens where outage ownership is allocated to ensure that system functionality worked properly in all cases. BPA indicated no responses that indicated the Schedulers accessed the screens differently than the tests revealed;
5. tested systems to ensure that functionality to update ownership shares is working correctly based on how the outage ownership screen can be accessed;
6. clarified its desk-level procedure that covers governing the allocation of the shared ownership ATC path and addresses the identified process gap; and
7. required Real-Time staff to review the revised desk-level procedure and sign the sheet indicating they have reviewed and understand it.

**Other Factors**

WECC reviewed BPA's internal compliance program (ICP) and considered it to be a neutral factor.

On August 22, 2014, in Southwestern Power Administration (SWPA) v. Federal Energy Regulatory Commission (FERC), the United States Court of Appeals for the District of Columbia Circuit unanimously ruled that FERC, and by extension, the North American Electric Reliability Corporation (NERC) and the Regional Entities it oversees, such as WECC, could not impose monetary penalties against federal governmental entities such as SWPA. BPA is a federal governmental entity, and WECC is bound to follow SWPA v. FERC in the resolution of this matter. Therefore, WECC has assessed no monetary penalty for this violation.

WECC considered BPA’s MOD-029-1a R2 and MOD-029-2a R2 compliance history to be an aggravating factor in determining the disposition track specifically NERC Violation IDs WECC2015014760, WECC201102885 and WECC2015015334.
NERC Violation ID | Reliability Standard | Req. | Violation Risk Factor | Violation Severity Level | Violation Start Date | Violation End Date | Method of Discovery | Mitigation Completion Date | Date Regional Entity Verified Completion of Mitigation |
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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, 2018, BPA submitted a Self-Report stating, as a Transmission Operator (TOP), it was in violation of MOD-029-2a R2, R2.6. Specifically, on June 4, 2018, BPA correctly posted the TTC on one ATC path, but did not correctly allocate between affected Transmission Owners (TOs) while allocating a seasonal limit, as required by its contractual allocation agreement. BPA allocated an additional 16 MW for one entity and 16 MW below the requirement for another entity. Further, there were no curtailments during this time. However, BPA corrected the TTC allocation that same day. The root cause of this instance was attributed to the desk-level procedure not specifying how to allocate the TTC during a seasonal limit. This violation began on June 4, 2018, when BPA did not correctly allocate the TTC for one ATC path, and ended on June 4, 2018, when BPA corrected the TTC allocation for the ATC path for a total of one day of noncompliance.

Risk Assessment

This violation posed a minimal risk and did not pose a serious and substantial risk to the reliability of the BPS. In this instance, BPA failed to use the following process to determine TTC: where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path, as required by MOD-029-2a R2. In this instance, BPA correctly posted the TTC on one ATC path, but did not correctly allocate between the TOs while allocating a seasonal limit, as required by its contractual allocation agreement. Such failure is a commercial operational issue, and presents a negligible potential harm to the reliability of the BPS.

BPA implemented weak preventative controls to prevent the violation. However, BPA implemented strong detective controls; specifically, it implemented a process for conducting next day capacity checks that detected the instance on June 4, 2018 with MOD-029-2a R2. As compensation, MOD-029-2a is proposed for retirement due to its emphasis on commercial operations instead of the potential harm to the reliability of the BPS. In addition, the duration of each of the violation was one day, thus reducing the risk.

Mitigation

To mitigate this violation, BPA:

1) allocated the correct TTC;
2) MOD-029-2a is proposed for retirement by NERC due to its emphasis on contractual agreements and minimal affects to reliability of the BPS;
3) reinforced the training on the proper allocation for seasonal ratings; and
4) clarified the desk-level procedure to make the allocation of seasonal ratings across this path clearer and provided training on the update desk-level procedure to the Real-time schedulers.

Other Factors

WECC reviewed BPA’s internal compliance program (ICP) and considered it to be a neutral factor.

On August 22, 2014, in Southwestern Power Administration (SWPA) v. Federal Energy Regulatory Commission (FERC), the United States Court of Appeals for the District of Columbia Circuit unanimously ruled that FERC, and by extension, the North American Electric Reliability Corporation (NERC) and the Regional Entities it oversees, such as WECC, could not impose monetary penalties against federal governmental entities such as SWPA. BPA is a federal governmental entity, and WECC is bound to follow SWPA v. FERC in the resolution of this matter. Therefore, WECC has assessed no monetary penalty for this violation.

WECC considered BPA’s MOD-029-1a R2 and MOD-029-2a R2 compliance history to be an aggravating factor in determining the disposition track specifically NERC Violation IDs WECC2015014760, WECC201102885 and WECC2015015334.
On May 6, 2016, BPA submitted a Self-Report stating, as a Transmission Operator, it was in violation of MOD-029-1a R3. Specifically, on February 3, 2016, BPA implemented a 450 MW Transmission Reliability Margin (TRM) for one Available Transfer Capability (ATC) transmission path to account for uncertainties arising from simultaneous path interactions when the System Operating Limit (SOL) across the ATC transmission path is above 2,000 MW. TRM is the amount of transmission transfer capability needed to account for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. However, on three occasions, BPA set its TTC lower than the lowest provided SOL for the ATC transmission path for the implementation of the TRM. Effectively, this resulted in BPA not having a correct TRM methodology for calculating TRMs for 2,000 - 2,500 MW. The details of each occurrence are explained below.

On March 27, 2016, BPA’s SOL for the ATC transmission path was 2,500 MW for all hours. However, the joint owner for the ATC transmission path showed an SOL of 2,200 MW for one transmission line and 2,300 MW for another transmission line. BPA did not have a process to establish a TRM for the SOLs of 2,200 MW or 2,300 MW and yet it posted an SOL of 2,000 MW without TRM for all hours. Such failure could potentially delay the system restoration time of the neighboring entity or require the neighboring entity to shed load for a contingency. This instance of the violation occurred on March 27, 2016, when BPA did not establish the correct SOL for the ATC path, and ended on September 6, 2016, when BPA corrected its calculation for TRM for SOLs between 2000 MW and 2500 MW, for a total of 164 days of noncompliance.

On April 2, 2016, for the ATC transmission path mentioned previously, BPA’s SOL was 2,500 MW and again the joint owner’s SOL was 2,300 MW. Since BPA did not have a process for calculating TRM for an SOL of 2,300 MW, BPA posted an SOL of 2,000 MW for all hours. Such failure could potentially delay the system restoration time of the neighboring entity or require the neighboring entity to shed load for a contingency. This instance of the violation occurred on April 2, 2016, when BPA did not establish the correct SOL for the ATC path, and ended on September 6, 2016, when BPA corrected its calculation for TRM for SOLs between 2000 MW and 2500 MW, for a total of 158 days of noncompliance.

On April 8, 2016, at 4:14 PM, BPA received an increase to the SOL from 2,000 MW to 2,500 MW, from the joint owner of the ATC transmission path. BPA managed the transmission path scheduling every 15 minutes. However, BPA did not update the SOL for the two transmission lines, as was required, for the next scheduling increment; but instead only updated the SOL for one transmission line. This instance of the violation occurred on April 8, 2016, when BPA did not establish the correct SOL for the ATC transmission path, and ended on September 6, 2016, when BPA corrected its calculation for TRM for SOLs between 2000 MW and 2500 MW, for a total of 152 days of noncompliance.

The root cause was attributed gaps in the BPA’s process for calculating the correct TRM methodology for 2,000 - 2,500 MW, so BPA set its TTC lower than the lowest provided SOL for the ATC transmission path for the implementation of the TRM.

Risk Assessment

This violation posed a minimal risk and did not pose a serious and substantial risk to the reliability of the BPS. In these instances, BPA failed to establish the TTC at the lesser of the value calculated in R2 or any SOL for its ATC Path, as described above, pursuant to MOD-029-1a R3. Such failure is a commercial operational issue, rather than a risk to the reliability of the BPS. MOD-029-1a R3 was retired March 31, 2017.
<table>
<thead>
<tr>
<th>NERC Violation ID</th>
<th>Reliability Standard</th>
<th>Req.</th>
<th>Violation Risk Factor</th>
<th>Violation Severity Level</th>
<th>Violation Start Date</th>
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<th>Date Regional Entity Verified Completion of Mitigation</th>
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<td>WECC2016015730</td>
<td>MOD-029-1a</td>
<td>R3</td>
<td>Lower</td>
<td>Severe</td>
<td>3/27/2016 (when BPA did not establish the correct SOL for the ATC path)</td>
<td>9/6/2016 (when BPA corrected its calculation for TRM for SOLs between 2000 MW and 2500 MW)</td>
<td>Self-Report</td>
<td>10/30/2018</td>
<td>3/7/2019</td>
</tr>
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</table>

BPA had weak preventative controls to prevent the above noncompliance. However, BPA had effective detective controls to identify the noncompliance and upon doing so, remediated timely, thereby lessening the risk to the BPS. Specifically, the operations scheduling lead identified the noncompliance, during a compliance review. Further, as compensation, BPA posted a lower SOL across the ATC transmission path associated with this instant violation, which reduces risk of overloading the line or damaging equipment. No harm is known to have occurred.

### Mitigation

To mitigate this violation, BPA:

1. implemented a process that allowed the correct TTC for the ATC Path with a TRM for SOLs falling between 2,000 MW and 2,500 MW;
2. modified the NI SCADA screen to help prevent future user error;
3. sent an email reminder to Dispatch staff, reviewing the procedure for sending updated SOL's to Schedule;
4. completed functionality requirements to automate the TRM entry that is required to submit requirements to vendor;
5. reviewed system change order from vendor that incorporates the requirements and made any needed adjustments;
6. implemented functionality to production environment;
7. adjusted processes to account for the new functionality;
8. trained staff on the new functionality and processes; and
9. MOD-029-1a was retired March 31, 2017, and the successor requirement is proposed for retirement.

### Other Factors

WECC reviewed BPA's internal compliance program (ICP) and considered it to be a neutral factor.

On August 22, 2014, in Southwestern Power Administration (SWPA) v. Federal Energy Regulatory Commission (FERC), the United States Court of Appeals for the District of Columbia Circuit unanimously ruled that FERC, and by extension, the North American Electric Reliability Corporation (NERC) and the Regional Entities it oversees, such as WECC, could not impose monetary penalties against federal governmental entities such as SWPA. BPA is a federal governmental entity, and WECC is bound to follow SWPA v. FERC in the resolution of this matter. Therefore, WECC has assessed no monetary penalty for this violation.

WECC considered BPA’s MOD-029-1a compliance history to be an aggravating factor in determining the disposition track specifically NERC Violation IDs WECC2011008668 and WECC2013011728.
**Western Electricity Coordinating Council (WECC) Settlement Agreement O&P**

On August 22, 2014, in Southwestern Power Administration (SWPA) v. Federal Energy Regulatory Commission (FERC), the United States Court of Appeals for the District of Columbia Circuit unanimously ruled that FERC, and by extension, the North American Electric Reliability Corporation (NERC) and the Regional Entities it oversees, such as WECC, could not impose monetary penalties against federal governmental entities such as SWPA. BPA is a federal governmental entity, and WECC is bound to follow SWPA v. FERC in the resolution of this matter. Therefore, WECC has assessed no monetary penalty for this violation.

WECC considered BPA’s PRC-005-2(i) R3 compliance history to be an aggravating factor in determining the disposition track specifically NERC Violation IDs WECC2015015392, WECC2016016710, WECC201103045 and WECC2013012135.

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<tr>
<td>WECC2016016711</td>
<td>PRC-005-2(i)</td>
<td>R3</td>
<td>High</td>
<td>Lower</td>
<td>10/1/2015 (when BPA did not perform the required maintenance tasks for one VLA control battery)</td>
<td>12/20/2016 (when BPA completed the required maintenance tasks for one VLA control battery)</td>
<td>Self-Report</td>
<td>3/16/2017</td>
<td>4/25/2017</td>
</tr>
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</table>

**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 23, 2016, BPA submitted a Self-Report stating, as a Transmission Owner (TO), it was in violation of PRC-005-2(i) R3. Specifically, on December 19, 2016 during evidence gathering for a Self-Certification, BPA found one Vented Lead-Acid (VLA) control battery at one substation that was not inspected for unintentional grounds, per Table 1-4(a) of the Standard and Requirement. The required unintentional grounds inspections were not recorded for two reasons: first, BPA incorrectly thought that because the VLA control battery did not have automated ground detection equipment, the maintenance activities were not required; second, in July 2015, BPA had assessed that the substation subject to this violation did not support the BES elements, and therefore, the VLA control battery was not subject to the requirements of the Standard. However, in December 2016, BPA corrected its assumption because the VLA control battery at the substation supported distributed Under Frequency Load Shedding (UFLS), which qualified the VLA control battery as a BES element and subject to the requirements of PRC-005. As a result, BPA found one VLA control battery that did not have the required maintenance activities as far back as October 1, 2015 for its required four-month calendar intervals. This violation began on October 1, 2015, when BPA did not perform the required maintenance tasks for one VLA control battery, and ended on December 20, 2016, when BPA completed the required maintenance tasks for one VLA control battery, for a total of 447 days of noncompliance.

The root cause of this violation was attributed to BPA’s incorrect assumption regarding the requirements for Bulk Electric System (BES) elements, for one of its substations as well as an incorrect assumption about the lack of associated automated ground detection equipment, resulting in one VLA control battery not being included in the maintenance activities.

**Risk Assessment**

This violation posed a minimal risk and did not pose a serious and substantial risk to the reliability of the BPS. In this instance, BPA failed to maintain its Protection System Components that are included within the time-based maintenance program, for one VLA control battery in accordance with maximum maintenance intervals prescribed within Table 1-4(a) of PRC-005-2(i) R3. However, as a compensating measure, the VLA control battery subject to this violation did not require any settings changes, once the inspections were completed.

In addition, BPA’s substation operations group performed monthly inspections on all control batteries. Even though the maintenance was not performed, the battery had been inspected, thus reducing the potential harm to the BPS.

**Mitigation**

To mitigate this violation, BPA:

1. completed VLA control battery device inspection/maintenance;
2. confirmed the application of applicable inspection forms for all control batteries subject to the Standard;
3. reviewed and documented locations that support UFLS, utilizing the BES definition and confirmed that all control batteries at those locations were correctly identified;
4. reviewed and documented alignment of the “yes” BES Cascade indicator and PRC-005 subject equipment to ensure the applicable Control Batteries were marked;
5. updated Operations Inspection Standard language to clarify that locations with automated ground detection to alert staff that they will have manual readings completed until automated panels are installed;
6. updated substation maintenance control battery Subject Matter Expert document to outline feasibility of installing ground detection equipment at applicable locations; and
7. added the missing VLA control battery to the work management system as well as the voltage readings added to the other monthly readings.

**Other Factors**

WECC reviewed BPA’s internal compliance program (ICP) and considered it to be a neutral factor.

On August 22, 2014, in Southwestern Power Administration (SWPA) v. Federal Energy Regulatory Commission (FERC), the United States Court of Appeals for the District of Columbia Circuit unanimously ruled that FERC, and by extension, the North American Electric Reliability Corporation (NERC) and the Regional Entities it oversees, such as WECC, could not impose monetary penalties against federal governmental entities such as SWPA. BPA is a federal governmental entity, and WECC is bound to follow SWPA v. FERC in the resolution of this matter. Therefore, WECC has assessed no monetary penalty for this violation.

WECC considered BPA’s PRC-005-2(i) R3 compliance history to be an aggravating factor in determining the disposition track specifically NERC Violation IDs WECC2015015392, WECC2016016710, WECC201103045 and WECC2013012135.

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**Settlement Agreement O&P**

**Does Not Contest**
**Description of the Noncompliance**

For purposes of this 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 18, 2019, FirstLight Hydro Generating Company (the Entity) submitted a Self-Report stating that, as a Generator Owner (GO), it was in violation of FAC-008-3 R1. Based on additional information received from the Entity, NPCC has determined that FAC-008-1 R1 is more appropriate for processing this violation. During a periodic internal compliance review of the Cabot generating station Facility Rating documentation, the Entity hired an outside consultant to undertake a comprehensive evaluation of the ampacity rating methodology utilized for various transition equipment (e.g. short sections of cables, cable jumpers) in service from the collector bus up to the low side terminals of the main generator step-up transformer (GSU) at the Point of Interconnection (POI). The purpose of this assessment was to determine ampacity ratings using methods consistent with industry standards recommended by the standard/requirement (e.g. IEEE) with the aid of the Electrical Transient Analyzer Program (ETAP) computer software as opposed to the previous method of simply adopting the Original Equipment Manufacturer's (OEM) specifications and ratings. By implementing this improved methodology, new ampacity ratings were calculated for several components that had been designed and installed between 2001 and 2006, when the plant was owned by the local Transmission Owner (TO). The assessment, completed in July 2019, determined that the corrected ratings for a number of these components limit the Cabot generating station's rated capacity. The Entity determined that the Cabot generating station was the only facility impacted and the following elements were determined to be undersized: the cable spacing from the Switchgear through rooftop conduit penetration; the rooftop rectangular bar transition; the aluminum conductor steel-reinforced cable (ACSR) overhead conductors; the ACSR transition conductors to substation tubular bus; the open air tubular bus sections; and the transition from air tubular bus section to Transformer LV bushing.

NPCC determined the cause of the violation was a failure to detect the errors in the facility rating sheet. The contributing cause was that the station was upgraded between 2001 and 2006 when the plant was owned by the local TO (there have been three ownership changes since that time). The design work was done in 2000. During the station upgrade, new components were installed that have subsequently been identified as being undersized and/or improperly rated.

NPCC determined that this violation spans two versions of the Reliability Standard, as follows:

- FAC-008-1 R1, from August 23, 2007, when the Entity registered as a GO for the Cabot generating station until December 31, 2012 (the standard’s retirement date); and
- FAC-008-3 R1, from January 1, 2013 to July 11, 2019, when the Entity reduced the Cabot generating station maximum output by approximately 21.5 MVA to prevent overloading limiting electrical equipment.

NPCC further determined that, for purposes of this violation, there was no substantive change in the Entity’s compliance obligations under the two applicable Standard Requirements.

**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 (BPS).

Failure to install electrical equipment between a generator’s terminals and its GSU with adequate ampacity ratings that are consistent with established industry standards (e.g. ANSI and IEEE) may limit a generator’s output capacity. The Entity’s Cabot generating station is a conventional six-unit hydro-electric generating facility with an aggregate nameplate rating of 77.5 MVA and interconnected to the Entity’s host TO at a 115 kV substation. On July 11, 2019, after notifying its Reliability Coordinator (RC), ISO-NE, that several electrical components limit the Cabot generating station's rated capacity, the Entity reduced its output at the POI to 56 MVA and or/44.5 MW, the maximum power output allowed by the most limiting piece of equipment at the station. The Cabot generating station is continuously monitored via its SCADA system for real time operating data, alerts, alarms and trips. Historical data from June 1, 2016 through August 7, 2019 show that the current de-rated output capacity of 56 MVA has been exceeded 24 percent of the time with a maximum value of 69.54 MVA. However, the aforementioned engineering evaluation found no evidence of thermal stress on those electrical components that have been determined to have lower ampacity ratings than previously calculated. The Cabot generating station has a rated capacity that is approximately 3% of its RC's 2600 MW required Operating Reserves and has been operated at an average annual capacity factor of 54.4% in the period 2015-2018. Therefore, the Entity’s RC could have adequately compensated for a potential generation outage arising from this instance of noncompliance.

No harm is known to have occurred as a result of this violation.

**Mitigation**

To mitigate the violation, the Entity:

1. in coordination with its RC, ISO-NE, reduced the Cabot generating station maximum output in order to reflect the most limiting equipment in service at the station;
2. revised its Facility Rating Sheet to reflect the corrected ampacity ratings for the aforementioned electrical equipment; and
3. enhanced its existing procedure with language requiring:
   a. responsible staff to track, document, review, and approve any changes to Facility Rating Sheet(s); and
   b. designated personnel to receive training on this procedure as well as the most current version of the NERC Standard FAC-008.
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<td>NPCC2019021852</td>
<td>FAC-008-1</td>
<td>R1., R1.3</td>
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<td>Moderate</td>
<td>08/23/2007</td>
<td>07/11/2019</td>
<td>Self-Report</td>
<td>09/04/2019</td>
<td>09/19/2019</td>
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</table>

### Other Factors

NPCC reviewed the entity’s internal compliance program (ICP) and considered it to be a neutral factor in the penalty determination.

Although this violation posed a minimal risk to the reliability of the BPS, the violation was not appropriate for compliance exception processing. The entity’s Facility Rating was incorrect for a significant duration of time, and the entity needed to reduce the output of its generator Facility to reflect the most limiting equipment in series at the station.