NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
FRCC2018020720	PRC-005-6	R3.	Gainesville Regional Utilities (GRU)	NCR00032	11/24/2017	09/26/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible or confirmed noncompliance.)	On November 20, 2018, GRU submitted a Self-Report stating that, as a Distribution Provider, Generation Owner, and Transmission Owner, it was in violation of PRC-005-6 R3. This violation started on November 24, 2017, when the Entity did not complete one (1) component of the 18-month battery maintenance activities required for one (1) Vented Lead-Acid (VLA) battery bank of twenty-four (24) banks, and ended on September 26, 2018, when all maintenance activities were complete. During an internal review of battery maintenance records, it was discovered that the intercell/intracell testing for one (1) VLA battery bank had not been performed within the 18-month interval, as required by PRC-005-6 Table 1-4(a). The last recorded intercell/intracell test was conducted on May 23, 2016, making the next required test to be completed no later than November 23, 2017 (18 months). Prior to this discovery, the Entity had performed a complete test on September 26, 2018, or 28 months from the previous test (10 months beyond the maximum maintenance interval). An extent of condition review was conducted verifying there were no additional occurrences. The cause for this noncompliance was a lack of a uniform preventive maintenance (PM) schedule for the generating site batteries, which comprise eight (8) of the twenty-four (24) total PRC-005-6 batteries.
Risk Assessment	This violation posed a minimal risk and did not pose a serious or substantial risk to the reliability of the bulk power system. The risk is reduced because the Entity completed the monthly maintenance activities which included visual inspection of battery for cleanliness and corrosion, fluid level checks, measurement of cell specific gravities, electrolyte temperature, and terminal voltage. The Entity's failure to take intercell/intracell readings on the battery could result in a lack of awareness of battery deterioration, which could lead to battery failure. A battery failure could result in a misoperation of a BES system device, a local service interruption, and/or loss of ability to provide peaking support of up to 72.5 MW. Additionally, the Entity's total generation of 630 MWs is 1.25% of the Region. The Region determined that the Entity's compliance history (FRCC200900166, FRCC200900174, FRCC201000402) should not serve as a basis for applying a penalty due to different facts and circumstances. No harm is known to have occurred. The instant noncompliance is a repeat of FRCC2011008750 resulting in FFT treatment; however, FRCC2011008750 should not serve as an aggravating factor in applying a penalty.
Mitigation	To mitigate this violation, the Entity: 1) performed extent of condition review; 2) conducted root cause analysis; 3) established common battery PM schedules for all generation batteries; 4) revised the Protection System Maintenance Program to reflect changes in generation battery PMs; 5) created training materials; and 6) trained all applicable personnel on changes

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RFC2018018936	TOP-001-3	R9	Indianapolis Power & Light Company (IPL)	NCR00798	9/21/2017	1/4/2018	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On December 20, 2017, the entity submitted a Self-Report stating that, as a Transmission Operator, it was in noncompliance with TOP-001-3 R9. On September 21, 2017, the entity's Real-Time Assessment (RTA) did not converge for a timeframe greater than 30 minutes. (Specifically, the RTA was not converging for 8 hours and 10 minutes on September 21, 2017) The entity examined the issue and learned that potential (post-contingency) operating conditions were the only item not being met by the entity regarding the RTAs being performed. Operators in the Transmission Operations Control Center (TOCC) were monitoring the entity transmission system during this time. However, the entity did not notify MISO or its impacted interconnected utilities. (MISO did not notify the entity of any issues resulting from the Real-Time Contingency Analysis during the period of time that the entity was having issues with its RTAs.) Furthermore, after identifying the noncompliance, ReliabilityFirst and the entity verified that MISO's RTA and Contingency Analysis was fully functional on the date in question. The root cause of this noncompliance was the fact that the alarms operators received for non-converging State Estimator solutions did not provide enough information to the operators to easily determine when the 30 minute threshold was reached. This major contributing factor involves the management practice of grid operations, which includes maintaining situational awareness of operations and validating operations tools. This noncompliance started on September 21, 2017, when the entity's operators failed to make the requisite notification to MISO and ended on January 4, 2018, when ReliabilityFirst confirmed that the entity had actually made the requisite notification to MISO.
Risk Assessment	This noncompliance 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 involved in this noncompliance is a reduction in visibility of potential post-contingencies on the BPS. If these are not addressed and communicated properly, they could result in wider spread adverse impact on the BPS. This risk was mitigated in this case by the following factors. First, it was confirmed that MISO's RTA and Contingency Analysis was fully functional and operational on the date in question. Therefore, if an issue had occurred, MISO would have been aware of it independently from the entity's notification. Second, RTA is only one of many methods used to monitor the BPS and would not necessarily be the only indicator of a potential risk. For example, the entity's TOCC Operators were constantly monitoring the transmission system during the time of non-convergence. Other examples include Supervisory Control and Data Acquisition displays and energy management system alarms. ReliabilityFirst also notes that both the entity and MISO observed no BPS issues during the time of non-convergence. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) created and tested the alarm functionality. The entity implemented a new alarm notification; 2) created training based on the new alarm notification; and 3) provided training to the Transmission Operations Control Center Operators. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
RFC2017018693	VAR-002-4	R2	NRG Energy Services LLC - Morgantown (NRG Morgantown)	NCR11581	1/31/2016	9/7/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed noncompliance.)	On November 12, 2017, the entity submitted a Self-Report stating that, as a Generator Operator, it was in noncompliance with VAR-002-4 R2. During an internal compliance review, the entity discovered several failures to notify PJM, the Transmission Operator (TOP), through First Energy (FE), when the 30 minute voltage exceeded the assigned high voltage schedule, during select dates in 2016 and 2017. In total, the entity identified a total of 87 instances of noncompliance where it failed to notify its TOP. However, the majority of the voltage exceedances were only slightly higher than the high voltage limit. In fact, the average exceedance was .21% above the threshold, with the single highest exceedance being 1.12% above the threshold. Furthermore, FE informed the entity that there is a difference of minus .3 kV voltage at the substation, which, when taken into account, would reduce the number of exceedances by almost half. Additionally, the entity discovered that voltage monitoring and control is maintained at the generator step-up (GSU) transformer output with no visibility at the Interconnection point in violation of VAR-002-4 R2.3. Consequently, the entity had no methodology to convert the voltage measurement at the GUS transformer output to the voltage measurement at the point of Interconnection. The root cause of this noncompliance were (a) inadequate detective controls to notify operators to respond when nearing the voltage limit; and, (b) the fact that the entity did not have a methodology in place to convert the voltage at the GSU transformer output to the voltage level at the point of Interconnection. This noncompliance started on January 31, 2016, when the first voltage exceedance occurred, and ended on September 7, 2017, when the last voltage exceedance ended.
Risk Assessment	This noncompliance posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system based on the following factors. The risk posed by a Generator Operator failing to inform the TOP of a voltage or reactive power exceedance is that it could cause the TOP to be uncertain of what generator was creating or contributing to an abnormal voltage condition on the BPS. This uncertainty could impede the TOP's ability to take appropriate action. The risk posed by failing to accurately monitor and control the voltage at the point of Interconnection is that it could impede the generator's ability to automatically regulate the voltage to maintain the proper voltage. These risks are not minimal in this case because of the number of exceedances (i.e., 87) and the length of time over which they occurred. However, these risks are not serious in this case based on the following factors. First, the generating unit does not have enough reactive capability, due to its size (50 MWs), to make a significant change in the voltage level at the point of Interconnection. Second, the majority of the voltage exceedances were found only slightly higher than the high voltage limit (i.e., an average of 140.3 kV or .21% above the voltage threshold) with the single largest exception at 141.580 which is 1.12 % above the scheduled maximum level of 140kV. No harm is known to have occurred. ReliabilityFirst considered the entity's compliance history and determined there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, the entity: 1) instituted voltage data report from the distributed control system (DCS) at this site for exception reporting to be used as Catsweb quarterly control evidence; 2) changed entries in electronic log book to capture alarm limits and required response by operators; 3) created an advanced alarm for high voltage schedule set to initiate at 139.5 with a high-high alarm at 140 KV to provide adequate notification for operators to respond to when nearing the voltage limit; 4) created an advanced alarm for low voltage schedule set to initiate at 136.5 with a low-low alarm at 136 KV to provide adequate notification for operators to respond to when nearing the voltage limit; 5) instituted an alarm response procedure to include the new alarm limits and response requirements for the operators when this occurs; 6) monitored adherence to voltage schedule weekly until an automated or batch process of exception reported is developed; 7) trained all control board operators and Operations supervision on updated procedure and NRG OCC-VAR-002 Compliance procedure; 8) compared DCS voltage output with FE's voltage readings at Interconnection to determine correlation in voltage readings over load range and determine feasibility of retrieving PJUM and FE real time voltage profile for monitoring purposes; and 9) determined and implemented a means for definitive measurement or methodology of voltage monitoring at the Interconnection can be established. ReliabilityFirst has verified the completion of all mitigation activity.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2018019780	VAR-002-2b	R2	Carville Energy LLC (Carville)	NCR11479	7/3/2014	05/07/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On May 29, 2018, Carville submitted a Self-Report indicating that, as a Generator Operator, it was in noncompliance with VAR-002-3 R2. During an internal compliance review performed in August 2017, Carville determine that it had failed to meet the conditions of notification for deviations from the Voltage schedule provided by its TOP, Entergy Corporation. Entergy's Voltage Schedule Policy for Generating Facilities Interconnected to the Entergy Transmission System (Entergy Voltage Schedule) provides that during all times of the year, Carville is to maintain 232.3 kV with a tolerance band of +3 kV / -2 kV at its interconnection. Further Entergy's Voltage Schedule provides: Each plant should contact Entergy's operations control center immediately (within 30 minutes) upon meeting both of the following conditions: a. The discovery of a deviation from the prescribed schedule tolerance band. b. The plant has exhausted all means of controlling voltage or reactive power. Carville indicated that is has historically had difficulty maintaining the voltage schedule with all generators in automatic voltage control producing the respective reactive power during the summer months due to the increased system load demand during the summers. Further, Carville stated that until the internal compliance review, it believed it was in compliance with VAR-002-3 by following the terms of its January 2000 Interconnection and Operating Agreement (Operating Agreement) with Entergy. The Operating Agreement provides that "in the event that the voltage schedule is not being maintained, the Facility shall be operated (within the design limitations of the equipment in service at the time) to produce the maximum reactive power (MVAR) output available in an attempt to achieve the prescribed voltage schedule, provided that Entergy has requested other generators in the affective area (including but not limited to Entergy's generators) to produce maximum reactive power (MVAR) in an attempt to achieve the prescribed voltage." Carville estimated that during the months of June, July and August for the years 2015, 2016 and 2017, it deviated from the voltage schedule for 201 hours or 9% of the time in 2015, 429 hours or 19% of the time in 2016, and 884 hours or 40% of the time in 2017. The maximum Voltage schedule deviation experienced during these times was + 1.8 kV (.76%) / - 7.7 kV (3.3%). Carville indicated that it was not always operating at its maximum reactive power capability during the aforementioned times and did not always notify its TOP of the deviation from the Voltage schedule. The root cause of this noncompliance was Carville's incorrect assumption that complying with the terms of its Operating Agreement with Entergy was sufficient to achieve compliance with VAR-002-2b R2. This noncompliance started on July 3, 2014, the date of the first instance that Carville did not meet the conditions of notification for deviations from the Voltage schedule provided by its TOP, and ended on May 7, 2017, the last date Carville failed to meet the conditions of notification for deviations from the Voltage schedule provided by its TOP.
Risk Assessment	This noncompliance posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). Specifically, Carville is a 555 MW, 2x1 combined cycle generating facility that is interconnected to the BPS at 230 kV. Additionally, the noncompliance occurred over an extended period of time (two years and seven months) and during the summer months, a time the BPS is heavily loaded. Nevertheless, Carville indicated that it is rarely called upon by the TOP for voltage support and has always responded by providing the maximum reactive power available. No harm is known to have occurred. SERC determined that Carville's compliance history should not serve as a basis for applying a penalty. Carville has no relevant prior violations of VAR-002-3 R2 or any other standards that are similar in nature.
Mitigation	To mitigate this noncompliance, Carville: 1) trained operations personnel on the requirements of VAR-002-4; 2) requested and received a modification to the TOP's voltage schedule, providing for a more sustainable voltage schedule; 3) trained operations personnel and management on the new voltage schedule; and 4) implemented an alarm system to notify plant operators when plant voltage deviates from the voltage schedule.

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Violation Start Date	Violation End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2016016658	PRC-023-1	R1	Georgia Power Company (GPC)	NCR01247	7/1/2010	May 18, 2017	Self-Report	Completed

Description of the Violation (For purposes of this document, each violation at issue is described as a "violation," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On December 15, 2016, GPC submitted a Self-Report stating that, as a Transmission Owner, it was in noncompliance with PRC-023-1 R1. On April 27, 2016, during quarterly monitoring of internal controls by GPC Transmission Compliance, a GPC Control Center Support Engineer discovered an error with a relay setting for the Fortson – Tenaska 500 kV transmission line. Following the replacement of a 500 kV switch in 2015, which resulted in an increase in the line rating for the Fortson – Tenaska transmission line, GPC failed to adjust the protective relay setting to greater than 150% of the transmission line Facility Rating. As a result of the line rating increase, the protective relay limited the loadability of the Fortson – Tenaska transmission line to 147% of its highest seasonal Facility Rating (R1.1). Subsequent to the Self-Report submitted on December 15, 2016, GPC identified two additional instances of noncompliance with PRC-023-1 R1. In the first instance, as part of its mitigation plan for the December 15, 2016 self-reported instance, GPC reviewed all of its protective relays to ensure the protection relays were set above 150% of the highest seasonal Facility Rating of the associated transmission facility. The protective relays for the Big Shanty Bank A, Big Shanty Bank B, and Bowen Bank 10 autobank transformer facilities were set to limit the loadability of the autobank facilities to 149.85%, 149.85% and 149.91% of their respective highest seasonal Facility Rating (R1.11). In the second instance, on March 23, 2017, GPC identified a disparity between the Facility Rating information in its PRC-023 spreadsheet and the GPC Operations' Facility Ratings. Upon correcting the Facility Rating disparity, GPC discovered the protective relay for the McIntosh CC 1 - West McIntosh 230 kV transmission line limited the loadability of the transmission line to 140.4 % of its highest seasonal Facility Rating (R1.1). The root cause of this noncompliance was lack of a formal process for changing Facility Ratings and lack of managerial oversight. By not having a formal process for changing Facility Ratings, GPC utilized inexact hand calculations for the Low Side Back-up Over-Current relays in the autobank spreadsheet to calculate relay settings, which resulted in Facility Rating errors. Proper managerial oversight should have identified the undocumented process for changing Facility Ratings. This noncompliance started on July 1, 2010, the date PRC-023-1 became mandatory and enforceable and GPC failed to ensure the relay settings were set to limit the loadability, and ended on May 18, 2017, the date GPC corrected the relay settings for the relays that were not set to limit the loadability of the respective transmission facilities to greater than 150% of the highest seasonal Facility Rating.
Risk Assessment	This noncomplaince posed a moderate risk and did not pose a serious or substantial risk to the reliability of the bulk power system (BPS). GPC's failure to set protective relays so they did not operate at or below 150% of the highest seasonal Facility Rating of a transmission facility increased the risk that relays would unnecessary trip transmission facilities during system events that otherwise would not have caused a transmission facility outage. Notwithstanding, SERC determined that the risk to the BPS was mitigated because the incorrect 500 kV line relay settings would support at least 147% of the highest seasonal Facility Rating of the circuit. GPC operates its transmission system to withstand the loss of any single transmission facility without adversely affecting the continued operation of its transmission system The actual load on the 500 kV line during the period of non-compliance did not exceed 1084 amps, which is well below the original setting of 2,675 amps. Additionally, the improperly set protective relay errors were small – the largest error occurred for the McIntosh CC 1 – West McIntosh 230 kV transmission line where loadability of the transmission line was limited to 140.4 % of its highest seasonal rating. No harm is known to have occurred due to the incorrect relay settings. A Spreadsheet Notice of Penalty covering violation of PRC-023-1 R1 (SERC2011007157) for GPC was filed with FERC under NP12-27-000 on May 30, 2012. On June 29, 2012, FERC issued an order stating it would not engage in further review of the Notice of Penalty. GPC identified seven protection relays that were not set to operate above 150% of the highest seasonal Facility Rating of the associated transmission facilities. SERC determined that GPC's compliance history should not serve as a basis for applying a penalty. The current issue does not involve recurring conduct that was the same or similar to the conduct in the prior noncompliance. Whereas the prior violation resulted from omissions and a failure to follow approved change procedures, the instant violation is the result of incorrect relay settings due to mathematical errors. SERC determined that the repeat violation of PRC-023-1 does not represent a systemic problem with GPC's internal compliance program but is illustrative of lack of a formalized process and managerial oversight.
Mitigation	To mitigate this noncompliance, GPC: 1) changed the incorrect protective relay settings to comply with PRC-023-1; 2) implemented a formal process for changing Facility Ratings for GPC Operations; 3) created an informational user interface module in the GPC lines rating database to identify transmission line Facilities with pending changes in Ratings; 4) incorporated the calculations for Low Side Back-Up Over-Current (LSBUOC) load responsive relays into the autobank spreadsheet used to calculate relay settings; 5) removed the McIntosh circuit from service; 6) trained personnel in the use of the formal process for changing Facility Ratings for GPC Operations; and

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SERC2016016658	PRC-023-1	R1	Georgia Power Company (GPC)	NCR01247	7/1/2010	May 18, 2017	Self-Report	Completed
			7) completed a 100% review of PRC-023 relays.					

NERC Violation ID	Reliability Standard	Req.	Entity Name	NCR ID	Noncompliance Start Date	Noncompliance End Date	Method of Discovery	Future Expected Mitigation Completion Date
SERC2017018600	TOP-001-3	R13	Duke Energy Progress, LLC (DEP)	NCR01298	07/21/2017	07/21/2017	Self-Report	Completed

Description of the Noncompliance (For purposes of this document, each noncompliance at issue is described as a "noncompliance," regardless of its procedural posture and whether it was a possible, or confirmed violation.)	On November 7, 2017, Duke Energy Progress, LLC (DEP) submitted a Self-Report on behalf of Duke Energy Florida, LLC (DEF) stating that, as a Transmission Operator, DEF was noncompliant with TOP-001-3 R13. DEF did not perform a Real-time Assessment at least once every 30 minutes. DEP submitted the Self-Report under an existing Multi-regional Registered Entity Agreement. On July 21, 2017, the DEF Energy Control Center (ECC) performed a Backup Control Center (BUCC) functionality test. At 6:10 a.m., prior to initiating transfer of operations to the BUCC, DEF completed a Real-time Contingency Analysis (RTCA) assessment, i.e., Real-time Assessment. No contingencies were identified on DEF's transmission system by the RTCA assessment. Thereafter, DEF Energy Management System (EMS) Support Engineering initiated the EMS function at the primary ECC server to failover to the BUCC server. At 6:19 a.m., an RTCA assessment utilizing the BUCC EMS identified an unsupported number of contingencies. Notwithstanding the perceived problem with the BUCC EMS RTCA results, System Operators determined the DEF BUCC EMS was operational and providing valid real-time flows, generator output, frequency, and other EMS data. DEF System Operators subsequently determined that although the RTCA was solving, the results of the RTCA were not valid. At 6:47 a.m., System Operators attempted a manual RTCA assessment per DEF Standing Order TS115 using a parallel Study Contingency Analysis (STCA) program. System Operators determined the STCA assessment was also invalid. At 7:25 a.m., System Operators contacted EMS Support Engineering who began troubleshooting the RTCA application problem at 7:41 a.m. At 8:14 a.m., DEF completed a second STCA assessment utilizing modified 5:45 a.m. EMS data. Although, the STCA assessment did not utilize the most current EMS data, no contingencies were identified on DEF's transmission system. At 8:28 a.m., DEF informed its Reliability Coordinator (RC), Florida Reliability Coordinating Council that the DEF RTCA application was providing invalid solutions. The RC agreed to monitor its Real-time assessments to identify DEF contingencies until the DEF RTCA issue was resolved. At 8:30 a.m., DEF performed a third STCA utilizing modified EMS data from 8:14 a.m. No contingencies were identified on DEF's transmission system. At 8:45 a.m., DEF EMS Support Engineering restored normal operation of the BUCC RTCA application. It was determined that the RTCA application failure occurred because the EMS database at the BUCC was updated with incorrect generating unit data during the failover of the primary ECC server to the BUCC server. DEF's failure to ensure the performance of a Real-time Assessment within 30 minutes was attributed to: failure to stop and restart all process on all EMS servers following an EMS database update to ensure a relink of generating unit indexes in the EMS Transfer Manager; inadequate controls to verify that a Real-time Assessment occurred every 30 minutes; the RTCA application failure occurring concurrent with the BUCC functionality test; System Operator failure to implement protocols to mitigate the loss of the RTCA function; System Operator involvement in the investigation of the cause of the RTCA application failure; and System Operator confusion regarding the continued operation of the BUCC EMS, i.e., notwithstanding the erroneous contingencies generated by the RTCA application, the BUCC EMS continued to provide valid real-time flows, generator output, frequency, and other EMS data. This noncompliance started on July 21, 2017, at 6:40 a.m., the time by which DEF should have performed a Real-time Assessment following the, successful 6:10 a.m. Real-time Assessment, and ended on July 21, 2017, at 8:28 a.m., when the DEF RC began monitoring its Real-time Assessment for DEF contingences.

Risk Assessment	This noncompliance posed a moderate risk to the reliability of the bulk power system (BPS). The failure to ensure the performance of a Real-time Assessment of the transmission system every 30 minutes increases the risk that System Operators could be unaware of system conditions that would impact the reliability of the BPS. This lack of system awareness increases the risk that System Operators would not proactively mitigate system conditions that could result in instability, uncontrolled separation, or cascading outages. Here, DEF failed to perform a Real-time Assessment of its transmission system for one hour and forty-eight minutes. Additionally, DEF failed to timely report its inability to perform a Real-time Assessment to its RC and seek the RC's assistance in monitoring for contingencies on the DEF transmission system. SERC determined that this issue is appropriate for FFT disposition because: the failure to perform a Real-time Assessment occurred during morning hours when system conditions typically change, but change in a predictable manner; DEF continued to have Real-time EMS data available to monitor system status; the RC's Real-time Assessment capabilities were unaffected by the DEF RTCA failure; DEF employed the STCA process to provide near Real-time assessments; and neither DEF nor its RC identified pre-contingency or post-contingency conditions that required mitigating actions during the noncompliance. No harm is known to have occurred. SERC considered DEF's compliance history and determined that there were no relevant instances of noncompliance.
Mitigation	To mitigate this noncompliance, DEF: 1) ECC system operators implemented DEF Standing Order TS115 to run manual real-time assessments using STCA; 2) EMS support engineering troubleshot and then restarted the transfer manager application to relink the real-time EMS applications; 3) updated DEF Standing Order TS115 to include: a. actions to be taken when RTCA solves but results are invalid; b. notifying the FRCC RC; and c. pulling the last valid real-time savecase into EMS applications; 4) EMS support engineering updated failover procedures to include: a. pre-job brief with system operations prior to commencing; b. critical steps to notify system operations prior to performing; c. process to stop/start all servers after all database updates; d. EMS support engineering will be in a fixed location prior to any predetermined failovers; and e. opening a bridge line to be used for constant communication during failovers between system operations and EMS support engineering; 5) EMS support engineering provided a copy of the revised failover procedures to system operations; 6) updated EMS checklist for system operations to include RTCA contingency list after the failover coincides with the RTCA contingency list prior to the failover; and 7) provided system operations training on the following: a. the new failover procedures and EMS checklist; b. hands on demonstration using the DTS creating a save case and performing a manual real-time assessment; and c. communications protocols.