GEN-2023-GR3

GENERATOR REPLACEMENT STUDY

By Aneden Consulting and SPP Generator Interconnection

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EXECUTIVE SUMMARY

Pursuant to the Southwest Power Pool (SPP) Open Access Transmission Tariff (SPP tariff) Attachment V section 3.9 and SPP Business Practice 7800, Interconnection Customers can submit replacement requests for its Existing Generating Facilities. The Interconnection Customer of an Existing Generating Facility (EGF) with a Point of Interconnection (POI) at the Norton 115 kV Substation requested to be studied in the SPP Generator Replacement process.

GEN-2023-GR3, the Replacement Generating Facility (RGF), will connect at the existing POI, the Norton 115 kV Substation in the Southwestern Public Service (SPS) area.

The EGF has 80 MW of available replacement capacity, based on the EGF Generation Interconnection Agreement (GIA). This Study has been requested to evaluate the replacement configuration of 20 x Vestas V150 4.5 MW wind turbines with a proportionally reduced dispatch of 82 MW as specified by the Interconnection Customer. This generating capacity for the RGF (90 MW), exceeds its requested Interconnection Service amount of 80 MW. The injection amount of the RGF must be limited to 80 MW at the POI. As a result, the customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount.

The Generator Replacement Process consists of two parts: a Reliability Assessment Study and a Replacement Impact Study. The Reliability Assessment Study identifies any system impacts between the removal of the EGF from service and the commission date of the RGF and system adjustments to mitigate those issues. The Replacement Impact Study identifies whether the RGF is a Material Modification.

Reliability Assessment Study

In the Reliability Assessment Study initial operational and planning pre-screening, SPP determined that additional detailed analysis would be needed to fully determine the impact of removing the EGF from service. Study scoping discussions with the Interconnection Customer and Transmission Owner determined that the scope would include a planning assessment consisting of steady state and stability analyses. Ultimately, **no issues requiring mitigation** were identified.

Replacement Impact Study

Aneden Consulting (Aneden) was retained by SPP to perform the Replacement Impact Study (Impact Study) for GEN-2023-GR3.

SPP determined that steady state analysis was not required because the requested capacity of the RGF does not exceed the previously studied EGF output of 80 MW. In addition, the EGF was previously studied at maximum Interconnection Service under all necessary reliability conditions. However, SPP determined that short circuit and dynamic stability analyses were required as the turbine changed from Mitsubishi to Vestas turbines. The scope of this Impact Study included reactive power analysis, short circuit analysis, and dynamic stability analysis.

The results of the Impact Study showed that the requested replacement did not have a material adverse impact on the SPP transmission system. The requested generator replacement of the EGF with GEN-2023-GR3 was determined **not a Material Modification**.

As the requested replacement generating capacity is higher than its Interconnection Service, the customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the requested Interconnection Service amount. The monitoring and control scheme may be reviewed by the Transmission Owner (TO) and documented in Appendix C of the RGF GIA.

In accordance with FERC Order No. 827, the generating facility will be required to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation.

It is likely that the customer may be required to reduce its generation output in real-time, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Nothing in this study should be construed as a guarantee of transmission service or delivery rights. Transfer of an existing resource designation from the EGF to the RGF can be achieved by submitting a transfer of designation request pursuant to Section 30.2.1 of the SPP tariff. If the customer would like to obtain new deliverability to final customers, a separate request for transmission service must be requested on Southwest Power Pool's OASIS by the customer.

SCOPE OF STUDY

Pursuant to SPP tariff Attachment V section 3.9 and SPP Business Practice 7800, Interconnection Customers can submit replacement requests for its Existing Generating Facilities. A Generator Replacement Impact Study is an interconnection study performed to evaluate the impacts of replacing existing generation with new generation. Two analyses covering different time frames are evaluated:

- Reliability Assessment Study – study performed to evaluate the performance of the Transmission System for the time period between the date that the Existing Generating Facility (EGF) ceases commercial operations and the Commercial Operation Date (COD) of the Replacement Generating Facility (RGF).
- Replacement Impact Study – study performed to evaluate if the RGF has a material adverse impact on the SPP Transmission System.

For any impacts to the system identified in the Reliability Assessment Study, non-transmission solutions such as redispatch, remedial action schemes, or reactive setting adjustments will be identified to mitigate issues originating after the removal of the EGF from service and before the commission of the RGF.

If the Replacement Impact Study identifies any materially adverse impact from operating the RGF when compared to the EGF, such impacts shall be deemed a Material Modification.

RELIABILITY ASSESSMENT STUDY

The Reliability Assessment Study evaluates regional transmission impacts from removing the EGF from service.

Based on the initial operational and planning pre-screening, SPP determined that additional detailed analysis would be needed to fully determine the impacts of removing the EGF from service. After a study scoping discussion with the Interconnection Customer, SPP determined that the scope of the Reliability Assessment Study would only include a Planning Analysis. The Planning Analysis consisted of steady state and stability analyses to determine whether system constraints exist with the removal of the EGF.

REPLACEMENT IMPACT STUDY

Aneden Consulting (Aneden) was retained by SPP to perform the Replacement Impact Study (Impact Study) for GEN-2023-GR3. All analyses were performed using Siemens PTI PSS/E version 34 software.

STEADY STATE ANALYSIS

To determine whether steady state analysis is required, SPP evaluates if all required reliability conditions were previously studied. This is done by comparing the current DISIS steady state requirements versus the steady state analysis previously performed on the EGF. SPP determined that since the EGF was previously studied at maximum Interconnection Service under all necessary reliability conditions, no steady state analysis for the RGF is required.

STABILITY AND SHORT CIRCUIT ANALYSES

To determine whether stability and short circuit analyses are required, SPP evaluates the difference between the stability models and corresponding parameters and, if needed, the collector system impedance between the existing configuration and the requested replacement. Dynamic stability analysis and short circuit analysis would be required if the differences listed above may result in a significant impact on the most recently performed DISIS stability analysis.

REACTIVE POWER ANALYSIS

A reactive power analysis was performed on the requested replacement configuration as it is a non-synchronous resource. The reactive power analysis determines the capacitive effect at the POI caused by the project's collector system and transmission line's capacitance. A shunt reactor size is determined in order to offset the capacitive effect and maintain zero (0) MVAr flow at the POI while the project's generators and capacitors (if any) are offline.

STUDY LIMITATIONS

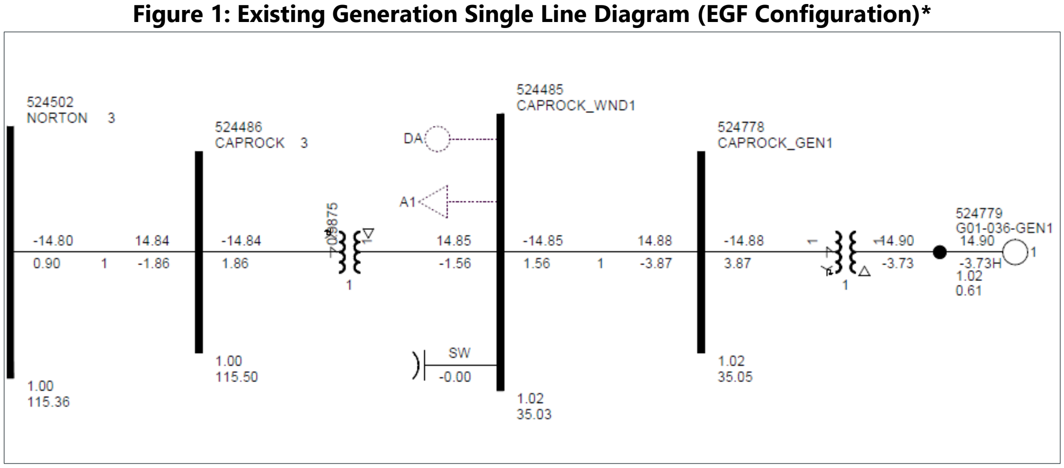
The assessments and conclusions provided in this report are based on assumptions and information provided to SPP/Aneden by others. While the assumptions and information provided may be appropriate for the purposes of this report, SPP/Aneden does not guarantee that those conditions assumed will occur. In addition, SPP/Aneden did not independently verify the accuracy or completeness of the information provided. As such, the conclusions and results presented in this report may vary depending on the extent to which actual future conditions differ from the assumptions made or information used herein.

PROJECT AND REPLACEMENT REQUEST

The GEN-2023-GR3 Interconnection Customer has requested a replacement to its EGF, a wind generating facility with a POI at the Norton 115 kV Substation and a requested retirement date of September 16, 2024. The Interconnection Service available for replacement is 80 MW, based on the EGF Generation Interconnection Agreement (GIA). Of the Interconnection Service available, the RGF Interconnection Customer has requested 80 MW of Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). The requested RGF is a wind farm consisting of 20 x Vestas V150 4.5 MW wind turbines with a proportionally reduced dispatch of 82 MW as specified by the Interconnection Customer. This generating capacity for the RGF (90 MW), exceeds its requested Interconnection Service amount of 80 MW. The injection amount of the RGF must be limited to 80 MW at the POI. As a result, the customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount. The RGF has a planned commercial operation date of December 31, 2024.

The POI of the EGF and RGF is at the Norton 115 kV Substation in the Southwestern Public Service (SPS) area, and the EGF and RGF are not expected to be operational simultaneously. Figure 1 and Figure 2 show the steady state model single-line diagram for the EGF and RGF configurations, respectively. Table 1 details the existing and replacement configurations for GEN-2023-GR3.

Figure 1: Existing Generation Single Line Diagram (EGF Configuration)*



*based on the DISIS-2017-002-1 25SP stability models

Figure 2: GEN-2023-GR3 Single Line Diagram (RGF Configuration)

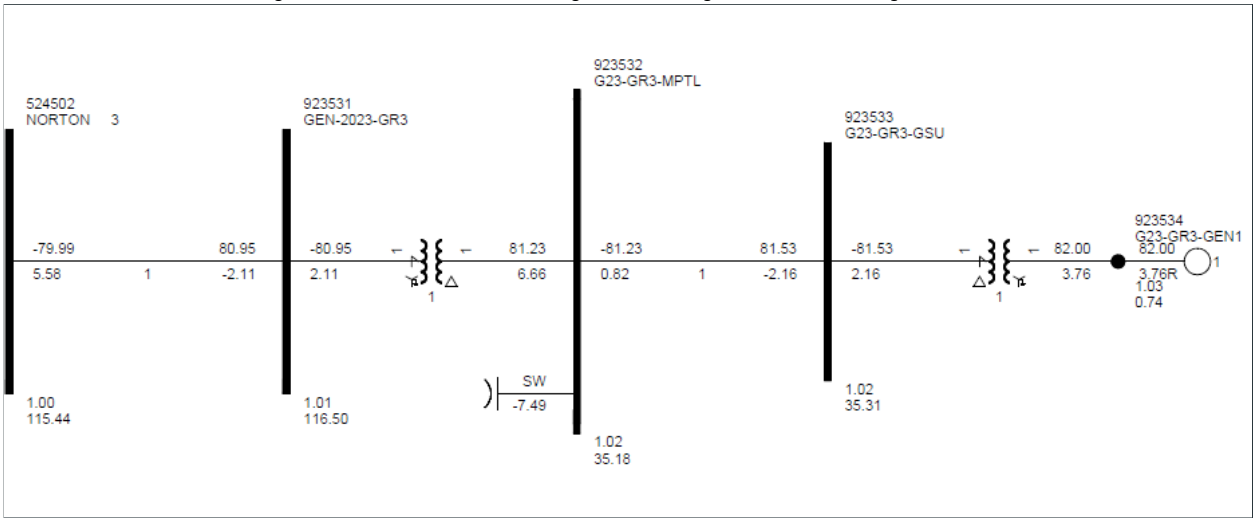


Table 1: EGF and RGF Configuration Details

Facility	Existing Generator Facility Configuration	Replacement Generator Facility Configuration
Point of Interconnection	Norton 115 kV Substation (524502)	Norton 115 kV Substation (524502)
Configuration/Capacity	80 x Mitsubishi 1.0 MW (wind) = 80 MW	20 x Vestas V150 4.5 MW (wind) = 90 MW [82 MW dispatch] PPC to limit GEN-2023-GR3 to 80 MW at the POI
Generation Interconnection Line	Length = 14.79 miles R = 0.015000 pu X = 0.072000 pu B = 0.011110 pu Rating MVA = 119.5 MVA	Length = 14.79 miles R = 0.015000 pu X = 0.072000 pu B = 0.011110 pu Rating MVA = 119.5 MVA
Main Substation Transformer	X^2 = 13.729%, R^2 = 0.413, Voltage = 34.5/115 kV (Delta/Wye Grounded), Taps Available = 33 Taps, ±10% Winding MVA = 100 MVA, Rating MVA = 90 MVA	X^1 = 7.413%, R^1 = 0.237%, Voltage = 34.5/115 kV (Delta/Wye Grounded), Taps Available = 33 Taps, ±10% Winding MVA = 54 MVA, Rating MVA = 90 MVA
Generator Step Up Transformer[1]	Gen 1 Equivalent Qty: 80 X = 6%, R = 0.98%, Voltage = 0.6/34.5 kV, Taps Available = 5 Taps, ±5% Winding MVA = 100 MVA, Rating MVA = 100 MVA	Gen 1 Equivalent Qty: 20 X = 9.869%, R = 0.789%, Voltage = 0.72/34.5 kV, Taps Available = 5 Taps, ±5% Winding MVA = 106 MVA, Rating MVA = 106 MVA
Equivalent Collector Line[3]	R = 0.014167 pu X = 0.050910 pu B = 0.023500 pu	R = 0.004740 pu X = 0.005374 pu B = 0.016046 pu
Generator Dynamic Model[4] & Power Factor	80 x Mitsubishi 1.0 MW (WT1G1)[4] Leading: 1.0 Lagging: 1.0	20 x Vestas V150 4.5 MW (REGCA1)[4] Leading: 0.942 Lagging: 0.87
Reactive Power Devices	9 x 3.6 MVAR 34.5 kV Capacitor Bank	2 x 3.6 MVAR 34.5 kV Capacitor Bank

1) X and R based on Winding MVA, 2) X and R based on System MVA, 3) All pu are on 100 MVA Base, 4) DYR stability model name

RELIABILITY ASSESSMENT STUDY

PLANNING ANALYSIS

Based on the initial operational and planning pre-screening, and a study scoping discussion with the Interconnection Customer, SPP determined that the scope of the Reliability Assessment Study would only include a Planning Analysis. The Planning Analysis consisted of steady state and stability analyses to determine whether system constraints exist with the removal of the EGF. The planning analysis was performed using the 2023 ITP Base Reliability models.

MODEL DEVELOPMENT

BASE CASE

The following 2023 TPL models were used as base cases for the steady state analysis:

- 2024 Light Load

The following 2023 TPL models were used as base cases for the stability analysis:

- 2024 Light Load

The 2024 Light Load model was selected based on the period of time between the EGF's requested retirement date of September 16, 2024 and the RGF's planned commercial operation date of December 31, 2024. The base cases have the EGF dispatched according to the TPL models, while SPP created change cases where the EGF was removed from the base cases to demonstrate the retirement of the EGF. SPP then compared the performance of both sets of cases to determine the impact of removing the EGF from service to the SPP transmission system.

ANALYSIS RESULTS

STEADY STATE ANALYSIS

Aneden was retained by SPP to perform the Planning Steady State Analysis portion of the Reliability Assessment Study (Assessment Study) for GEN-2023-GR3.

Aneden compared the base cases to the change cases by using PowerGEM TARA software to perform the steady state analysis and determine the impacts of removing the EGF from service.

The following assumptions were made for the steady state analysis:

- Monitored Elements
  - SPP facilities 69 kV and above
  - First-tier companies 100 kV and above
- Contingencies
  - P1, P2, P3, P4, P5, P6 and P7 events[1] within 5 buses of the EGF's POI for all models
- Impact Criteria
  - The system performance in the base and study cases were evaluated based on the SPP Planning Criteria[2] (Section 5.4.2).
  - Any new voltage violations or thermal violations were identified as new impacts

The results of the steady state analysis showed that there were some high voltage violations seen in the area around the Norton 115 kV POI bus due to reactive power being injected from the EGF topology. To resolve this, the EGF collector system, capacitor banks, and DVARs were taken offline.

In addition, there were some borderline high voltages around the Oasis 115 kV bus and the downstream 69 kV system. These high voltages were resolved by adjusting the capacitor bank on the TIERABLANCA3 115 kV bus to produce 0 MVAR.

Overall, there were no thermal or voltage impacts identified in the change cases due to the EGF retirement. As no impacts were observed in the study area, removing the EGF from service was determined to meet SPP Planning Criteria.

STABILITY ANALYSIS

SPP Staff performed the stability analysis portion of the Reliability Assessment Study (Assessment Study) for GEN-2023-GR3. SPP Staff utilized the transient stability contingencies that were developed during the 2023 Planning Assessment for the Southwest Public Service (SPS) Transmission Planning area.

A transient stability analysis using PSS/E was performed for these member-submitted events for the 2024 Light Load base and change cases. The contingencies included P1-P7 Planning and Extreme Events for a total of 155 events.

[1] NERC TPL-001 Standard Table 1
[2] SPP Planning Criteria Revision 4.3, November 6, 2023

The simulations were performed for 20 seconds, and the following parameters were monitored according to the SPP Disturbance Performance Requirements[3]:

- Rotor angle stability within the SPP Planning Coordinator (PC) Area
- Oscillation damping within the SPP PC Area
- Transient voltage stability within 10 buses of the fault bus

SPP Staff compared the post processed results from the base and change cases to determine the impact on the SPP Bulk Electric System (BES).

The results of the transient stability analysis showed that there were no rotor angle stability, oscillation damping, or transient voltage stability violations identified in the change cases due to the EGF retirement. As no impacts were observed in the study area, removing the EGF from service was determined to meet SPP Disturbance Performance Requirements and Planning Criteria.

[3] SPP Disturbance Performance Requirements:
https://www.spp.org/documents/28859/spp%20disturbance%20performance%20requirements%20(twg%20approved).pdf

REPLACEMENT IMPACT STUDY

Aneden was retained by SPP to perform the Replacement Impact Study (Impact Study) for GEN-2023-GR3.

EXISTING VS. REPLACEMENT COMPARISON

To determine which analyses are required for the Impact Study, the differences between the existing configuration and the requested replacement were evaluated. SPP performed this comparison and the resulting analyses using a set of modified study models developed based on the replacement request data and the DISIS-2017-002-1 study models.

STABILITY MODEL PARAMETERS COMPARISION

Because of the turbine change from Mitsubishi to Vestas turbines, SPP determined that short circuit and dynamic stability analyses were required. This is because the short-circuit contribution and stability responses of the existing configuration and the requested replacement's configuration may differ. The generator dynamic model for the RGF can be found in Appendix A.

As short-circuit and dynamic stability analyses were required, a stability model parameters comparison was not needed for the determination of the scope of the study.

EQUIVALENT IMPEDANCE COMPARISON CALCULATION

As the stability model change determined that short circuit and dynamic stability analyses were required, an equivalent impedance comparison was not needed for the determination of the scope of the study.

REACTIVE POWER ANALYSIS

Aneden performed a reactive power analysis for GEN-2023-GR3 to determine the capacitive charging effects under reduced generation conditions (unsuitable wind speeds, unsuitable solar irradiance, insufficient state of charge, idle conditions, curtailment, etc.) at the generation site and to size shunt reactors that would reduce the project reactive power contribution to the POI to approximately zero.

METHODOLOGY AND CRITERIA

The GEN-2023-GR3 generators and capacitor were switched out of service while other system elements remained in-service. A shunt reactor was tested at the project's collection substation 34.5 kV bus to set the MVAr flow into the POI to approximately zero. The size of the shunt reactor is equivalent to the charging current value at unity voltage and the compensation provided is proportional to the voltage effects on the charging current (i.e., for voltages above unity, reactive compensation is greater than the size of the reactor).

Aneden performed the reactive power analysis using the replacement request data based on the DISIS-2017-002-1 stability study 2025 Summer Peak (25SP) model.

RESULTS

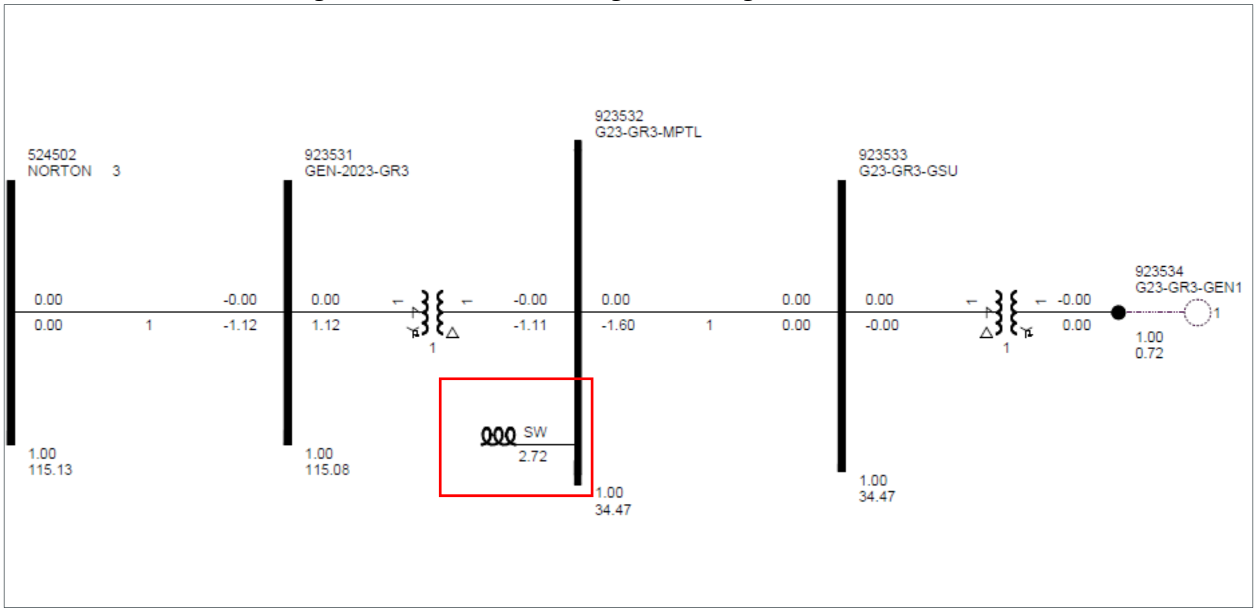
The results from the analysis showed that the GEN-2023-GR3 project needed approximately 2.72 MVAr of compensation at its collector substation, to reduce the POI MVAr to zero. Figure 3 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the replacement configuration. The final shunt reactor requirements for GEN-2023-GR3 are shown in Table 2.

The information gathered from the reactive power analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator (TOP). The applicable reactive power requirements will be further reviewed by the TO and/or TOP.

Table 2: Shunt Reactor Size for Reactive Power Analysis

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)
			25SP
GEN-2023-GR3	524502	NORTON 3	2.72

Figure 3: GEN-2023-GR3 Single Line Diagram (Shunt Sizes)



SHORT-CIRCUIT ANALYSIS

Aneden performed a short circuit study using the 25SP model to determine the maximum fault current requiring interruption by protective equipment with the RGF online for each bus in the relevant subsystem, and the amount of increase in maximum fault current due to the addition of the RGF. The detailed results of the short circuit analysis are provided in Appendix B.

METHODOLOGY

The short-circuit analysis included applying a three-phase fault on buses up to five levels away from the 115 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels in the transmission system with and without the GEN-2023-GR3 RGF online.

SPP created a short circuit model using the 25SP stability study model by adjusting the GEN-2023-GR3 short-circuit parameters consistent with the replacement data. The adjusted parameters are shown in Table 3 below.

Table 3: GEN-2023-GR3 Short-Circuit Parameters*

Parameter	Value by Generator Bus#
	923534
Machine MVA Base	106
R (pu)	0
X'' (pu)	0.93458

*pu values based on Machine MVA Base

RESULTS

The results of the short circuit analysis for the 25SP model are summarized in Table 4 and Table 5. The GEN-2023-GR3 POI bus (Norton 115 kV) fault current magnitude is provided in Table 4 showing a fault current of 2.52 kA with the RGF online. The addition of the RGF increased the POI bus fault current by 0.42 kA. Table 5 shows the maximum fault current magnitudes and fault current increases with the RGF project online.

The maximum fault current calculated within 5 buses of the POI was 27.37 kA for the 25SP model. The maximum contribution to three-phase fault currents due to the addition of the RGF was about 19.9% and 0.42 kA.

Table 4: POI Short-Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	kA Change	%Change
25SP	2.10	2.52	0.42	19.9%

Table 5: 25SP Short-Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	4.85	0.01	1.7%
115	10.63	0.42	19.9%
230	27.37	0.05	0.7%
345	11.07	0.01	0.1%
Max	**27.37**	**0.42**	**19.9%**

DYNAMIC STABILITY ANALYSIS

Aneden performed a dynamic stability analysis to identify the impact of the GEN-2023-GR3 project. The analysis was performed according to SPP's Disturbance Performance Requirements[4]. The replacement details are described in the Project and Replacement Request section and the dynamic modeling data is provided in Appendix A. The existing base case issues and simulation plots can be found in Appendix C.

METHODOLOGY AND CRITERIA

The dynamic stability analysis was performed using models developed with the requested RGF configuration of 20 x Vestas V150 4.5 MW (REGCA1). This stability analysis was performed using PTI's PSS/E version 34.8.0 software.

The RGF project details were used to create modified stability models for this impact study based on the DISIS-2017-002-1 stability study models:

- 2025 Summer Peak (25SP)
- 2025 Winter Peak (25WP)

The dynamic model data for the GEN-2023-GR3 project is provided in Appendix A. The modified power flow models and associated dynamics database were initialized (no-fault test) to confirm that there were no errors in the initial conditions of the system and the dynamic data.

The following system adjustments were made to address existing base case issues that are not attributed to the replacement request:

- The frequency protective relays at buses 761442, 761445, 761447, and 761449 were disabled after observing the generators tripping during initial three phase fault simulations. This frequency tripping issue is a known PSS/E limitation when calculating bus frequency as it relates to non-conventional type devices.
- The voltage protective relays at buses 761442, 761445, 761447, and 761449 were disabled to avoid generator tripping due to an instantaneous over voltage spike after fault clearing.
- The WTDTA1 drive train model was disabled at buses 560759 and 560762 to mitigate mechanical model driven SPD and active power high frequency oscillations and deviations (seen in the cases with and without the RGF).

[4] SPP Disturbance Performance Requirements: https://www.spp.org/documents/28859/spp%20disturbance%20performance%20requirements%20(twg%20approved).pdf

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for the EGF and SGF and other current and prior queued projects in Group 5[5]. In addition, voltages of five (5) buses away from the POI of the RGF were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas including 520 (AEPW), 524 (OKGE), 526 (SPS), and 652 (WAPA) were monitored. The voltages of all 100 kV and above buses within the study area were monitored as well.

FAULT DEFINITIONS

Aneden developed fault events as required to study the RGF. The new set of faults were simulated using the modified study models. The fault events included three-phase faults and single-line-to-ground stuck breaker faults. Single-line-to-ground faults are approximated by applying a fault impedance to bring the faulted bus positive sequence voltage to 0.6 pu. The simulated faults are listed and described in Table 6. These contingencies were applied to the modified 25SP and 25WP models.

Table 6: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT9001-3PH	P1	3 phase fault on the PLSNT_HILL3 (524768) to N_CLOVIS_TP3 (524776) 115 kV line CKT 1, near PLSNT_HILL3. a. Apply fault at the PLSNT_HILL3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	P1	3 phase fault on the PLSNT_HILL3 (524768) to E_CLOVIS 3 (524773) 115 kV line CKT 1, near PLSNT_HILL3. a. Apply fault at the PLSNT_HILL3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9003-3PH	P1	3 phase fault on the PLSNT_HILL3 (524768) to FE_HOLLAND 3 (524831) 115 kV line CKT 1, near PLSNT_HILL3. a. Apply fault at the PLSNT_HILL3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1	3 phase fault on the PLSNT_HILL 115 kV (524768) /230 kV (524770) /13.2 kV (524767) XFMR CKT 1, near CROSBY 3 115 kV. a. Apply fault at the PLSNT_HILL3 (524768) 115 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9006-3PH	P1	3 phase fault on the NORTON 3 (524502) to FE-TUCMCARI3 (524509) 115 kV line CKT 1, near NORTON 3. a. Apply fault at the NORTON 3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. Trip generators on bus A13-002-GEN1 (560759), QUAY_CNTY (524471) c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.

[5] Based on the DISIS-2017-002 Cluster Groups

Table 6 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9007-3PH	P1	3 phase fault on the FE-TUCMCARI3 (524509) to LOPEZ 3 (524472) 115 kV line CKT 1, near FE-TUCMCARI3. a. Apply fault at the FE-TUCMCARI3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. Trip generators on bus QUAY_CNTY (524471) c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	P1	3 phase fault on the N_CLOVIS_TP3 (524776) to N_CLOVIS 3 (524777) 115 kV line CKT 1, near N_CLOVIS_TP3. a. Apply fault at the N_CLOVIS_TP3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9009-3PH	P1	3 phase fault on the N_CLOVIS_TP3 (524776) to FE-CLVS_INT3 (524808) 115 kV line CKT 1, near N_CLOVIS_TP3. a. Apply fault at the N_CLOVIS_TP3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9010-3PH	P1	3 phase fault on the FE-CLVS_INT3 (524808) to W_CLOVIS 3 (524784) 115 kV line CKT 1, near FE-CLVS_INT3. a. Apply fault at the FE-CLVS_INT3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9011-3PH	P1	3 phase fault on the FE-CLVS_INT3 (524808) to A12-02&13-05 (583280) 115 kV line CKT 1, near FE-CLVS_INT3. a. Apply fault at the FE-CLVS_INT3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. **Trip generators on bus A13-003-GEN1 (560762) and A12021305GEN (583283)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9012-3PH	P1	3 phase fault on the E_CLOVIS 3 (524773) to CURRY 3 (524822) 115 kV line CKT 1, near E_CLOVIS 3. a. Apply fault at the E_CLOVIS 3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9013-3PH	P1	3 phase fault on the FE-HOLLAND 3 (524831) to FE-CLOVIS2 (524838) 115 kV line CKT 1, near FE-HOLLAND 3. a. Apply fault at the FE-HOLLAND 3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9014-3PH	P1	3 phase fault on the CURRY 115 kV (524822) /69 kV (524821) /13.2 kV (524819) XFMR CKT 1, near CURRY 3 115 kV. a. Apply fault at the CURRY 3 (524822) 115 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9015-3PH	P1	3 phase fault on the CURRY 3 (524822) to DS-#20 (524669) 115 kV line CKT 1, near CURRY 3. a. Apply fault at the CURRY 3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9016-3PH	P1	3 phase fault on the CURRY 3 (524822) to NORRIS_TP 3 (524764) 115 kV line CKT 1, near CURRY 3. a. Apply fault at the CURRY 3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.

Table 6 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9017-3PH	P1	3 phase fault on the CURRY 3 (524822) to BAILEYCO 3 (525028) 115 kV line CKT 1, near CURRY 3. a. Apply fault at the CURRY 3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9018-3PH	P1	3 phase fault on the CURRY 3 (524822) to ROOSEVELT 3 (524908) 115 kV line CKT 2, near CURRY 3. a. Apply fault at the CURRY 3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9019-3PH	P1	3 phase fault on the PLSNT_HILL 6 (524770) to ROOSEVELT 6 (524909) 230 kV line CKT 1, near PLSNT_HILL 6. a. Apply fault at the PLSNT_HILL 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9020-3PH	P1	3 phase fault on the PLSNT_HILL 6 (524770) to G17-116-TAP (761467) 230 kV line CKT 1, near PLSNT_HILL 6. a. Apply fault at the PLSNT_HILL 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9021-3PH	P1	3 phase fault on the ROOSEVELT 6 230 kV (524909) /115 kV (524908) /13.2 kV (524907) XFMR CKT 1, near ROOSEVELT 6 230 kV. a. Apply fault at the ROOSEVELT 6 (524909) 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9022-3PH	P1	3 phase fault on the ROOSEVELT 6 (524909) to TOLK 6 (525531) 230 kV line CKT 1, near ROOSEVELT 6. a. Apply fault at the ROOSEVELT 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9023-3PH	P1	3 phase fault on the ROOSEVELT 6 (524909) to OASIS 6 (524875) 230 kV line CKT 1, near ROOSEVELT 6. a. Apply fault at the ROOSEVELT 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9024-3PH	P1	3 phase fault on the G17-116-TAP (761467) to OASIS 6 (524875) 230 kV line CKT 1, near G17-116-TAP. a. Apply fault at the G17-116-TAP 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9025-3PH	P1	3 phase fault on the G17-116-TAP (761467) to GEN-2017-116 (761460) 230 kV line CKT 1, near G17-116-TAP. a. Apply fault at the G17-116-TAP 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. **Trip generators on bus G17-116-GEN1 (761463) and G17-116-GEN2 (761466)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9026-3PH	P1	3 phase fault on the OASIS 230 kV (524875) /115 kV (524874) /13.2 kV (524872) XFMR CKT 1, near OASIS 6 230 kV. a. Apply fault at the OASIS 6 (524875) 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.

Table 6 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9027-3PH	P1	3 phase fault on the OASIS 6 (524875) to SN_JUAN_TAP6 (524885) 230 kV line CKT 1, near OASIS 6. a. Apply fault at the OASIS 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9028-3PH	P1	3 phase fault on the TOLK 230 kV (525531) /24 kV (525561) XFMR CKT 1, near TOLK 6 230 kV. a. Apply fault at the TOLK 6 (525531) 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer. **Trip the generator on bus TOLK 1 (525561)**
FLT9029-3PH	P1	3 phase fault on the TOLK 230 kV (525531) /24 kV (525562) XFMR CKT 1, near TOLK 6 230 kV. a. Apply fault at the TOLK 6 (525531) 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer. **Trip the generator on bus TOLK 1 (525562)**
FLT9030-3PH	P1	3 phase fault on the TOLK 230 kV (525531) /345 kV (525549) /13.2 kV (525537) XFMR CKT 1, near OASIS 6 230 kV. a. Apply fault at the TOLK 6 (525531) 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9031-3PH	P1	3 phase fault on the TOLK 6 (525531) to GEN-2017-158 (762132) 230 kV line CKT 1, near TOLK 6. a. Apply fault at the TOLK 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. **Trip generators on bus G17-158GEN1 (762135) and G17-158GEN2 (762138)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9032-3PH	P1	3 phase fault on the TOLK 6 (525531) to NEEDMORE 6 (525586) 230 kV line CKT 1, near TOLK 6. a. Apply fault at the TOLK 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9033-3PH	P1	3 phase fault on the TOLK 6 (525531) to TUCO_INT 6 (525830) 230 kV line CKT 1, near TOLK 6. a. Apply fault at the TOLK 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9034-3PH	P1	3 phase fault on the TOLK 6 (525531) to LAMB_CNTY 6 (525637) 230 kV line CKT 1, near TOLK 6. a. Apply fault at the TOLK 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9035-3PH	P1	3 phase fault on the TOLK 6 (525531) to G17-218TAP (762174) 230 kV line CKT 1, near TOLK 6. a. Apply fault at the TOLK 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9036-3PH	P1	3 phase fault on the TOLK 7 (525549) to CROSSROADS 7 (527656) 345 kV line CKT 1, near TOLK 7. a. Apply fault at the TOLK 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.

Table 6 Continued

Fault ID	Planning Event	Fault Descriptions
FLT1001-SB	P4	**Stuck Breaker on at PLSNT_HILL 3 (524768) at 115kV** a. Apply single-phase fault at PLSNT_HILL 3 (524768) on the 115kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the PLSNT_HILL 115 kV (524768) /230 kV (524770) /13.2 kV (524767) XFMR CKT 1. d. Trip the PLSNT_HILL3 (524768) to N_CLOVIS_TP3 (524776) 115 kV line CKT 1.
FLT1002-SB	P4	**Stuck Breaker on at PLSNT_HILL 3 (524768) at 115kV** a. Apply single-phase fault at PLSNT_HILL 3 (524768) on the 115kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the PLSNT_HILL3 (524768) to E_CLOVIS 3 (524773) 115 kV line CKT 1. d. Trip the PLSNT_HILL3 (524768) to NORTON 3 (524502) 115 kV line CKT 1. Trip generators on bus CAPROCK_SLR1 (524491), A13-002-GEN1 (560759), QUAY_CNTY (524471),G23-GR3-GEN1 (923534)
FLT1003-SB	P4	**Stuck Breaker on at PLSNT_HILL 6 (524770) at 230kV** a. Apply single-phase fault at PLSNT_HILL 6 (524770) on the 230kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the whole bus PLSNT_HILL 6 (524770)
FLT1004-SB	P4	**Stuck Breaker on at NORTON 3 (524502) at 115kV** a. Apply single-phase fault at NORTON 3 (524502) on the 115kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the NORTON 115 kV (524502) /34.5 kV (524491) XFMR CKT 1. d. Trip the NORTON 3 (524502) to GEN-2023-GR3 (923531) 115 kV line CKT 1. Trip generators on bus CAPROCK_SLR1 (524491) and G01-036-GEN1 (923534)
FLT1005-SB	P4	**Stuck Breaker on at NORTON 3 (524502) at 115kV** a. Apply single-phase fault at NORTON 3 (524502) on the 115kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the NORTON 3 (524502) to PLSNT_HILL3 (524768) 115 kV line CKT 1. d. Trip the NORTON 3 (524502) to GEN-2023-GR3 (923531) 115 kV line CKT 1. Trip generators on bus CAPROCK_SLR1 (524491), A13-002-GEN1 (560759), QUAY_CNTY (524471),G23-GR3-GEN1 (923534)
FLT1006-SB	P4	**Stuck Breaker on at NORTON 3 (524502) at 115kV** a. Apply single-phase fault at NORTON 3 (524502) on the 115kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the NORTON 3 (524502) to PLSNT_HILL3 (524768) 115 kV line CKT 1. d. Trip the NORTON 3 (524502) to FE-TUCMCARI3 (524509) 115 kV line CKT 1. Trip generators on bus CAPROCK_SLR1 (524491), A13-002-GEN1 (560759), QUAY_CNTY (524471),G23-GR3-GEN1 (923534)
FLT1007-SB	P4	**Stuck Breaker on at NORTON 3 (524502) at 115kV** a. Apply single-phase fault at NORTON 3 (524502) on the 115kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the NORTON 115 kV (524502) /34.5 kV (524491) XFMR CKT 1. . d. Trip the NORTON 3 (524502) to FE-TUCMCARI3 (524509) 115 kV line CKT 1. Trip generators on bus CAPROCK_SLR1 (524491), A13-002-GEN1 (560759), QUAY_CNTY (524471)

RESULTS

Table 7 shows the relevant results of the fault events simulated for each of the modified cases. Existing DISIS base case issues are documented separately in Appendix C. The associated stability plots are also provided in Appendix C.

Table 7: Stability Analysis Results

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9027-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9028-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9029-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9030-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9031-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9032-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9033-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9034-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9035-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9036-3PH	Pass	Pass	Stable	Pass	Pass	Stable

Table 7 Continued

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable

The results of the dynamic stability analysis showed several existing base case issues that were found in both the original DISIS-2017-002-1 model and the model with GEN-2023-GR3 included. These issues were not attributed to the GEN-2023-GR3 replacement request and are detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2023-GR3 replacement request observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

INSTALLED CAPACITY EXCEEDS GIA CAPACITY

Under FERC Order 845, Interconnection Customers are allowed to request Interconnection Service that is lower than the full generating capacity of their planned generating facilities. The Interconnection Customers must install acceptable control and protection devices that prevent the injection above their requested Interconnection Service amount measured at the POI.

NECESSARY INTERCONNECTION FACILITIES

This study identified necessary Interconnection Facilities to accommodate GEN-2023-GR3 as shown in Table 8.

Table 8: Necessary Interconnection Facilities

Upgrade Name	Upgrade Description
Norton 115 kV GEN-2023-GR3 Interconnection (TOIF) (SPS)	Interconnection upgrades and cost estimates needed to interconnect the following Interconnection Customer facility, GEN-2023-GR3, into the POI at Norton 115 kV.
Norton 115 kV GEN-2023-GR3 Interconnection (Non-Shared NU) (SPS)	Interconnection upgrades and cost estimates needed to interconnect the following Interconnection Customer facility, GEN-2023-GR3, into the POI at Norton 115 kV.

Should the Interconnection Customer choose to move forward with this request, an Interconnection Facilities Study will be necessary to determine the full scope, cost, and time required to interconnect these upgrades. SPP will work with the TO(s) indicated for the Interconnection Facilities Study.

RESULTS

RELIABILITY ASSESSMENT STUDY

In accordance with Attachment V and Business Practice 7800, the Reliability Assessment Study for Generator Replacements evaluates regional transmission impacts from removing the EGF from service and any non-transmission mitigations necessary for those impacts.

Based on the findings of the Reliability Assessment Planning Analysis, **no mitigations will be necessary** due to the removal of the EGF from service.

REPLACEMENT IMPACT STUDY

In accordance with SPP tariff Attachment V, any material adverse impact from operating the RGF when compared to the EGF would be identified as a Material Modification. In the case that the Interconnection Customer chooses to move forward with the RGF, it must submit the RGF as a new Interconnection Request.

Because no material adverse impacts to the SPP Transmission System were identified, SPP determined the requested replacement is **not a Material Modification**. SPP determined that the requested replacement did not cause a materially adverse impact to the dynamic stability and short-circuit characteristics of the SPP system.

This determination implies that no new upgrades beyond those required for interconnection of the RGF are required, thus not resulting in a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date.

NEXT STEPS

As the requested replacement is determined to not be a Material Modification, pursuant to SPP tariff Attachment V section 3.9.3, the Interconnection Customer shall inform SPP within 30 Calendar Days after having received these study results of its election to proceed.

If the Interconnection Customer chooses to proceed with the studied replacement, SPP will initiate an Interconnection Facilities Study and subsequently tender a draft GIA. The Interconnection Customer shall withdraw any associated Attachment AB retirement requests of the EGF, if applicable, and complete the Attachment AE requirements for de-registration of the EGF and registration of the RGF, including transfer or termination of applicable existing transmission service. If the Interconnection Customer would like to obtain new deliverability to final customers, a separate request for transmission service must be requested on Southwest Power Pool's OASIS.

Failure by the Interconnection Customer to provide an election to proceed within 30 Calendar Days will result in withdrawal of the Interconnection Request pursuant to section 3.7 of SPP tariff Attachment V.