Report on

GEN-2024-SR1
Surplus Service Impact Study

Revision R1 September 18, 2024

Submitted to
Southwest Power Pool

anedenconsulting.com

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPENDICES

Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
9/18/2024	Aneden Consulting	Initial Report Issued

Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Surplus Interconnection Service Impact Study (Study) for GEN-2024-SR1 to utilize the Surplus Interconnection Service being made available by the legacy unit GREC 2 at its existing Point of Interconnection (POI), the GRDA1 345 kV Substation in the Grand River Dam Authority (GRDA) control area.

GEN-2024-SR1, the proposed Surplus Generating Facility (SGF), will connect to the GREC 2 POI bus (GRDA1 345 kV) via a separate bay connection.

GREC 2, the Existing Generating Facility (EGF), has a nameplate POI capacity of 524.8 MW and is making 84 MW of Surplus Interconnection Service available at its POI. Per the SPP Open Access Transmission Tariff (SPP Tariff), the amount of Surplus Interconnection Service available to the SGF is limited by the amount of Interconnection Service granted to the EGF at the same POI. In addition, the Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring Network Upgrades except those specified in the SPP Tariff[1].

The proposed SGF configuration consists of 23 x Sungrow SG4400UD-MV solar inverters operating at 3.635 MW for a total assumed dispatch of 83.605 MW. The inverters are rated at 4.4 MVA, thus the generating capability of the SGF exceeds its requested Surplus Interconnection Service of 84 MW. The injection amount of the SGF must be limited to 84 MW at the POI. The combined generation from both the SGF and the EGF may not exceed 524.8 MW at the POI. GEN-2024-SR1 includes the use of a Power Plant Controller (PPC) to limit the power injection as required. The SGF and EGF information is shown in Table ES-1 below.

The detailed SGF configuration is captured in Table ES-2 below.

Table ES-1: EGF & SGF Configuration

Request	Interconnection Queue Capacity (MW)	Fuel Type	Point of Interconnection
GEN-2024-SR1 (SGF)	84	Solar	GRDA1 345 kV (512650)
GREC 2 (EGF)	524.8	Conventional	GRDA1 345 kV (512650)

[1] Allowed Network Upgrades detailed in SPP Open Access Transmission Tariff Attachment V Section 3.3

Table ES-2: SGF Interconnection Configuration

Facility	SGF Configuration
Point of Interconnection	GRDA1 345 kV (512650)
Configuration/Capacity	23 x Sungrow SG4400UD-MV 3.635 MW (solar) = 83.605 MW [dispatch] Units are rated at 4.4 MVA, PPC to limit GEN-2024-SR1 to 84 MW at the POI and total POI injection w/ GREC 2 to 524.8 MW
Generation Interconnection Line	N/A
Main Substation Transformer[1]	X = 8.998%, R = 0.18%, Winding MVA = 132 MVA, Rating MVA = 220 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 23 X = 7.949%, R = 0.9%, Winding MVA = 92.889 MVA, Rating MVA[2] = 92.9 MVA
Equivalent Collector Line[3]	R = 0.005320 pu X = 0.003930 pu B = 0.009728 pu
Generator Dynamic Model[5] & Power Factor	23 x Sungrow SG4400UD-MV 4.03865 MVA[4] (REGCAU1)[5] Leading: 0.9 Lagging: 0.9

1) X and R based on Winding MVA, 2) Rating rounded in PSS/E, 3) All pu are on 100 MVA Base, equivalent based on average derated MVA base provided by IC, 4) Average aggregated MVA provided by IC, 5) DYR stability model name

SPP determined that steady-state analysis was not required because the addition of the SGF does not increase the maximum active power output of 524.8 MW. In addition, the EGF is a Legacy unit and as such was not subject to a DISIS steady-state analysis.

The scope of this study included reactive power analysis, short circuit analysis, and dynamic stability analysis.

Aneden performed the analyses using the study data provided for the SGF and the DISIS-2018-002/2019-001 study models:

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

All analyses were performed using the Siemens PTI PSS/E[2] version 34 software and the results are summarized below.

The results of the reactive power analysis using the 25SP model showed that the SGF project needed a 1.0 MVAr shunt reactor at the project substation to reduce the POI MVAr to zero. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during reduced generation conditions. 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.

[2] Power System Simulator for Engineering

The short circuit analysis was performed using the 25SP stability model modified for short circuit analysis. The results from the short circuit analysis compared the 25SP model with the EGF online and SGF not connected to the SGF study model (EGF and SGF online). The maximum contribution to three-phase fault currents in the immediate transmission systems due to the addition of the SGF was not greater than 0.2 kA. The maximum three-phase fault current level within 5 buses of the POI with the EGF and SGF generators online was 44.134 kA for the 25SP model. There were several buses with a maximum three-phase fault current over 40 kA. These buses are highlighted in Appendix B.

The dynamic stability analysis was performed using Siemens PTI PSS/E version 34.8.0 software for the two modified study models: 25SP and 25WP, each with two dispatch scenarios. 88 fault events were simulated, which included three-phase faults and single-line-to-ground stuck breaker faults.

- Scenario 1: SGF at maximum assumed dispatch, 83.605 MW, and EGF disconnected.
- Scenario 2: SGF at maximum assumed dispatch, 83.605 MW, and EGF dispatched with the remaining 442.3 MW for a total POI injection of 524.8 MW.

The results of the dynamic stability analysis showed several existing base case issues that were found in both the original DISIS-2018-002/2019-001 model and in the model with GEN-2024-SR1 included. These issues were not attributed to the GEN-2024-SR1 surplus request and are detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2024-SR1 surplus 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.

The results of the study showed that the Surplus Interconnection Service Request by GEN-2024-SR1 did not negatively impact the reliability of the Transmission System. There were no additional Interconnection Facilities or Network Upgrades identified by the analyses.

SPP has determined that GEN-2024-SR1 may utilize the requested 84 MW of Surplus Interconnection Service being made available by the EGF. The combined generation from both the SGF and the EGF may not exceed 524.8 MW at the POI.

The customer must install monitoring and control equipment as needed to ensure that the SGF does not exceed the granted surplus amount and to ensure that combination of the SGF and EGF power injected at the POI does not exceed the EGF's Interconnection Service amount. The monitoring and control scheme may be reviewed by the TO and documented in Appendix C of the SGF GIA.

In accordance with FERC Order No. 827, the SGF 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 to 0 MW 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. If the customer wishes to obtain deliverability to final customers, a separate request for transmission service must be requested on Southwest Power Pool's OASIS by the customer.

1.0 Scope of Study

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Surplus Service Impact Study (Study) for GEN-2024-SR1, the Surplus Generating Facility (SGF). A Surplus Service Impact Study is performed to identify the impact of the Surplus Interconnection Service on the transmission system reliability and any additional Interconnection Facilities necessary pursuant to the SPP Generator Interconnection Procedures ("GIP") contained in Attachment V Section 3.3 of the SPP Open Access Transmission Tariff (SPP Tariff). The amount of Surplus Interconnection Service available to the SGF is limited by the amount of Interconnection Service granted to the existing interconnection customer for the Existing Generating Facility (EGF) at the same POI. The Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades except those specified in the SPP Tariff[3]. The required scope of the study is dependent upon the EGF and SGF specifications. The criteria sections below include the basis of the analyses included in the scope of study.

All analyses were performed using the Siemens PTI PSS/E version 34 software. The results of each analysis are presented in the following sections.

1.1 Reactive Power Analysis

SPP requires that a reactive power analysis be performed on the requested configuration if it is a non-synchronous resource. The reactive power analysis determines the added capacitive effect at the POI caused by the project's collection system and transmission line's capacitance. A shunt reactor size was determined for the SGF to offset the capacitive effect and maintain zero (0) MVAr injection at the POI while the plant's generators and capacitors were offline.

1.2 Short Circuit Analysis

SPP requires that a short circuit analysis be performed to determine the maximum available fault current requiring interruption by protective equipment with both the SGF and EGF online, along with the amount of increase in maximum fault current due to the addition of the SGF. The analysis was performed on two scenarios, with the EGF in service and SGF offline, and the modified model with both EGF and SGF in service.

1.3 Stability Analysis

SPP requires that a dynamic stability analysis be performed to determine whether the SGF, EGF, and the transmission system will remain stable and within applicable criteria. Dynamic stability analysis was performed on two dispatch scenarios, the first where the SGF was online at 100% of the assumed dispatch with the EGF offline and disconnected, and the second where the SGF was online at 100% of the assumed dispatch and the EGF was picking up the remaining EGF capacity. The stability analyses will identify any additional Interconnection Facilities and Network Upgrades necessary.

1.4 Steady-State Analysis

The steady-state (thermal/voltage) analyses may be performed as necessary to ensure that all required reliability conditions are studied. If the EGF was not studied under off-peak conditions, off-peak steady state analyses shall be performed to the required level necessary to demonstrate reliable operation of the Surplus Interconnection Service. If the original system impact study is not available for the Interconnection Service, both off-peak and peak analysis may need to be performed for the EGF associated with the request.

[3] Allowed Network Upgrades detailed in SPP Open Access Transmission Tariff Attachment V Section 3.3

An SGF that includes a fuel type (synchronous/non-synchronous) different from the EGF may require a steady-state analysis to study impacts resultant from changes in dispatch to all equal and lower queued requests. The steady-state analyses will identify any additional Interconnection Facilities and Network Upgrades necessary.

1.5 Necessary Interconnection Facilities & Network Upgrades

The SPP Tariff[4] states that the reactive power, short circuit/fault duty, stability, and steady-state analyses (where applicable) for the Surplus Interconnection Service will identify any additional Interconnection Facilities necessary. In addition, the analyses will determine if any Network Upgrades are required for mitigation. The Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades unless (a) those additional Network Upgrades are either (1) located at the Point of Interconnection substation and at the same voltage level as the Generating Facility with an effective GIA, or (2) are System Protection Facilities; and (b) there are no material adverse impacts on the cost or timing of any Interconnection Requests pending at the time the Surplus Interconnection Service request is submitted.

1.6 Study Limitations

The assessments and conclusions provided in this report are based on assumptions and information provided to Aneden by others. While the assumptions and information provided may be appropriate for the purposes of this report, Aneden does not guarantee that those conditions assumed will occur. In addition, 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.

[4] SPP Open Access Transmission Tariff Section 3.3.4.1

2.0 Surplus Interconnection Service Request

The GEN-2024-SR1 Interconnection Customer has requested a Surplus Interconnection Service Impact Study (Study) for GEN-2024-SR1 to utilize the Surplus Interconnection Service being made available by the legacy unit GREC 2 at its existing Point of Interconnection (POI), the GRDA1 345 kV Substation in the Grand River Dam Authority (GRDA) control area.

GEN-2024-SR1, the proposed Surplus Generating Facility (SGF), will connect to the GREC 2 POI bus (GRDA1 345 kV) via a separate bay connection.

GREC 2, the EGF, has a nameplate POI capacity of 524.8 MW and is making 84 MW of Surplus Interconnection Service available at its POI. Per the SPP Tariff the amount of Surplus Interconnection Service available to the SGF is limited by the amount of Interconnection Service granted to the EGF at the same POI. In addition, the Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades except those specified in the SPP Tariff.

At the time of the posting of this report, GREC 2 (EGF) is a legacy generator at the same POI (GRDA1 345 kV) that predates GRDA's membership in SPP and as such does not have a Generation Interconnection Agreement (GIA). Figure 2-1 shows the power flow model single line diagram for the EGF configuration. The existing EGF configuration in the DISIS-2018-002/2019-001 model has a maximum generator output of 520 MW, which is slightly lower than the attested 524.8 MW. The scenarios being studied for this surplus request did not require the EGF to be dispatched above the modeled 520 MW, so the EGF modeling was not altered for this study.

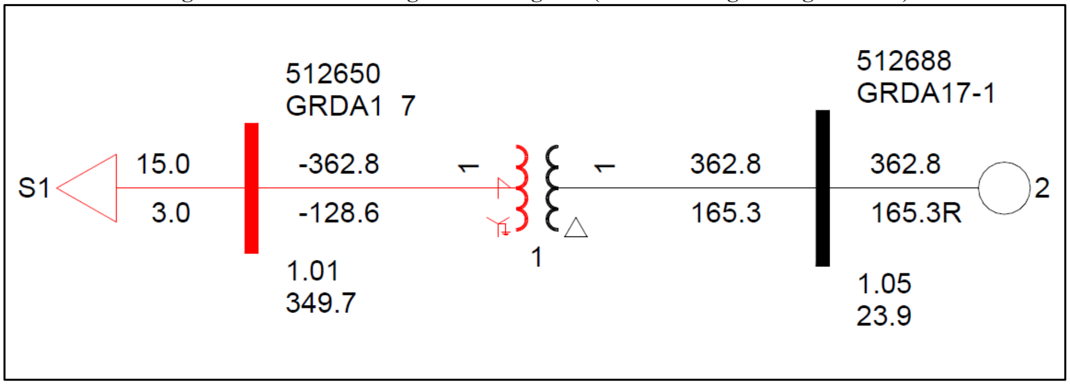
The proposed SGF configuration consists of 23 x Sungrow SG4400UD-MV solar inverters operating at 3.635 MW for a total assumed dispatch of 83.605 MW. The inverters are rated at 4.4 MVA, thus the generating capability of the SGF exceeds its requested Surplus Interconnection Service of 84 MW. The injection amount of the SGF must be limited to 84 MW at the POI. The combined generation from both the SGF and the EGF may not exceed 524.8 MW at the POI. GEN-2024-SR1 includes the use of a Power Plant Controller (PPC) to limit the power injection as required. The SGF and EGF information is shown in Table 2-1 below.

Table 2-1: EGF & SGF Configuration

Request	Interconnection Queue Capacity (MW)	Fuel Type	Point of Interconnection
GEN-2024-SR1 (SGF)	84	Solar	GRDA1 345 kV (512650)
GREC 2 (EGF)	524.8	Conventional	GRDA1 345 kV (512650)

The proposed detailed SGF configuration is captured in Figure 2-2 and Table 2-2 below.

Figure 2-1: GREC 2 Single Line Diagram (EGF Existing Configuration*)



*based on the DISIS-2018-002/2019-001 25SP stability models

Figure 2-2: GREC 2 & GEN-2024-SR1 Single Line Diagram (EGF & SGF Configuration)

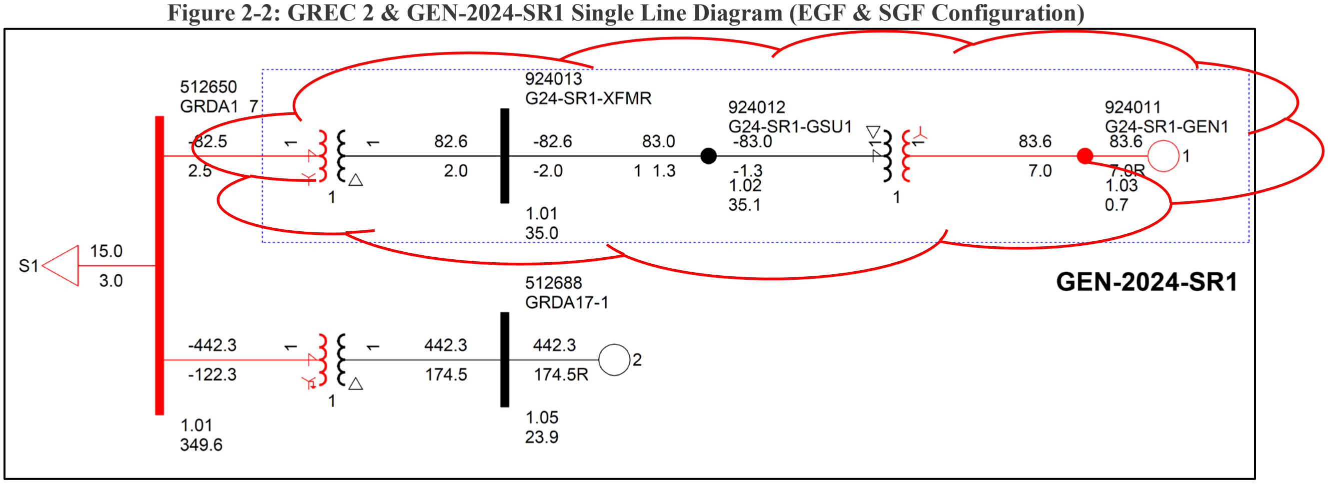


Table 2-2: SGF Interconnection Configuration

Facility	SGF Configuration
Point of Interconnection	GRDA1 345 kV (512650)
Configuration/Capacity	23 x Sungrow SG4400UD-MV 3.635 MW (solar) = 83.605 MW [dispatch] Units are rated at 4.4 MVA, PPC to limit GEN-2024-SR1 to 84 MW at the POI and total POI injection w/ GREC 2 to 524.8 MW
Generation Interconnection Line	N/A
Main Substation Transformer[1]	X = 8.998%, R = 0.18%, Winding MVA = 132 MVA, Rating MVA = 220 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 23 X = 7.949%, R = 0.9%, Winding MVA = 92.889 MVA, Rating MVA[2] = 92.9 MVA
Equivalent Collector Line[3]	R = 0.005320 pu X = 0.003930 pu B = 0.009728 pu
Generator Dynamic Model[5] & Power Factor	23 x Sungrow SG4400UD-MV 4.03865 MVA[4] (REGCAU1)[5] Leading: 0.9 Lagging: 0.9

1) X and R based on Winding MVA, 2) Rating rounded in PSS/E, 3) All pu are on 100 MVA Base, equivalent based on average derated MVA base provided by IC, 4) Average aggregated MVA provided by IC, 5) DYR stability model name

3.0 Reactive Power Analysis

The reactive power analysis was performed for GEN-2024-SR1 to determine the capacitive charging effects due to the SGF during 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.

3.1 Methodology and Criteria

To determine the shunt reactor size required to compensate for the current charging attributed to the SGF collection system all project generators were switched offline while other collector system elements remained in-service. A shunt reactor was tested at the project's collection substation 34.5 kV bus to reduce the MVAr injection at the POI to 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 SGF data based on the 25SP DISIS-2018-002/2019-001 stability study model.

3.2 Results

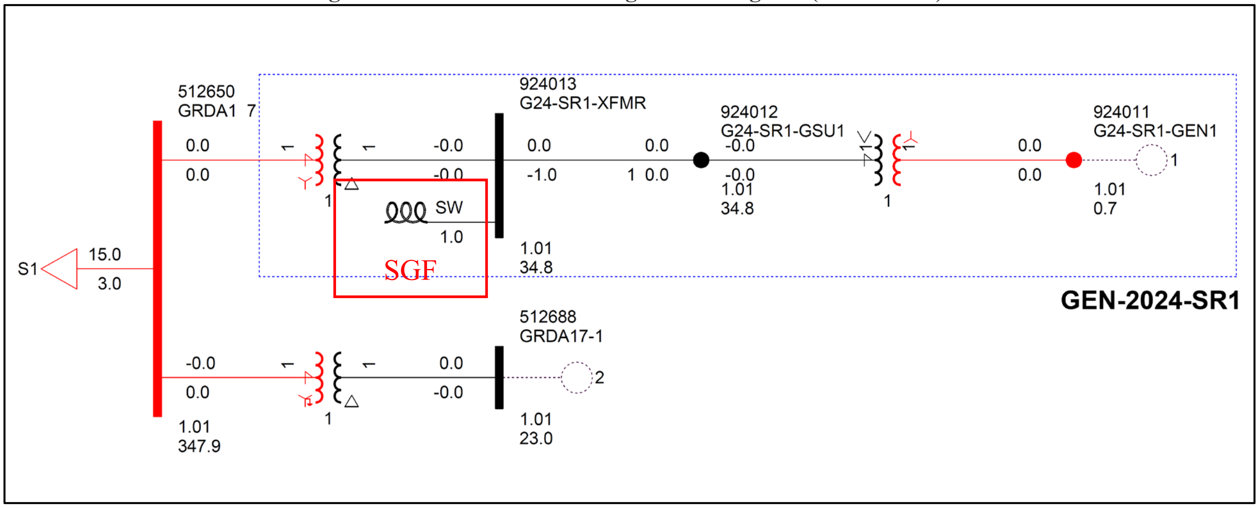
The results from the analysis showed that the SGF needed an approximately 1.0 MVAr shunt reactor at the SGF substation, to reduce the MVAr injection at the POI to zero. The final shunt reactor requirements are shown in Table 3-1. Figure 3-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero.

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 3-1: Shunt Reactor Size for Reactive Power Analysis

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)
			25SP
GEN-2024-SR1 (SGF)	512650	GRDA1 7	1.0

Figure 3-1: GEN-2024-SR1 Single Line Diagram (Shunt Sizes)



4.0 Short Circuit Analysis

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

4.1 Methodology

The short circuit analysis included applying a 3-phase fault on buses up to 5 levels away from the 345 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 SGF online. The first scenario was studied with both the SGF and EGF in service. In the second scenario the SGF was disconnected while the EGF was online to determine the impact of the SGF.

Aneden created a short circuit model using the 25SP DISIS-2018-002/2019-001 stability study model by adjusting the SGF short circuit parameters consistent with the submitted data. The adjusted parameters used in the short circuit analysis are shown in Table 4-1 below. No other changes were made to the model.

Table 4-1: Short Circuit Model Parameters*

Parameter	Value by Generator Bus#
	512650
Machine MVA Base	92.89
R (pu)	0.000
X'' (pu)	0.6147

*pu values based on Machine MVA Base

4.2 Results

The results of the short circuit analysis compared the 25SP model with the EGF online and SGF not connected to the stability Scenario 2 dispatch model with both the EGF and SGF in service as described in Section 5.1. The GEN-2024-SR1 POI bus (GRDA1 345 kV) fault current magnitudes for the comparison cases are provided in Table 4-2 showing a fault current of 26.27 kA with the EGF and SGF online. The addition of the SGF configuration increased the POI bus fault current by 0.2 kA. Table 4-3 shows the maximum fault current magnitudes and fault current increases with the SGF project online.

The maximum fault current calculated within 5 buses of the POI was 44.134 kA for the 25SP model. There were several buses with a maximum three-phase fault current over 40 kA. These buses are highlighted in Appendix B. The maximum contribution to three-phase fault currents due to the addition of the SGF was about 0.8% and 0.2 kA.

Table 4-2: POI Short Circuit Comparison Results

Case	EGF Only Current (kA)	SGF & EGF Current (kA)	kA Change	%Change
25SP	26.06	26.27	0.20	0.8%

Table 4-3: 25SP Short Circuit Comparison Results

Voltage (kV)	Max. Current (EGF & SGF) (kA)	Max kA Change	Max %Change
69	22.7	0.00	0.0%
115	17.4	0.01	0.0%
138	35.5	0.01	0.0%
161	44.1	0.11	0.3%
345	29.2	0.20	0.8%
Max	**44.1**	**0.20**	**0.8%**

5.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the SGF project. The analysis was performed according to SPP's Disturbance Performance Requirements[5]. The project details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix A. The existing base case issues and simulation plots can be found in Appendix C.

5.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested 23 x Sungrow SG4400UD-MV operating at 3.635 MW (REGCAU1) SGF generating facility configuration included in the models. This stability analysis was performed using Siemens PTI's PSS/E version 34.8.0 software.

Two stability model scenarios were developed using the models from DISIS-2018-002/2019-001. The first scenario (Scenario 1) was comprised of the SGF online at 100% of the assumed dispatch (SGF = 83.605 MW) while the EGF generator was offline and disconnected.

The second scenario (Scenario 2) was comprised of the SGF at 100% of the assumed dispatch (SGF = 83.605 MW) while the EGF generator picked up the remaining EGF capacity (EGF = 442.3 MW). The study scenarios are shown in Table 5-1.

Table 5-1: Study Scenarios (Generator Dispatch MW)

Scenario	GREC 2 EGF (MW)	GEN-2024-SR1 SGF (MW)	EGF + SGF (MW)
1	0 (Offline)	83.605	83.605
2	442.3	83.605	525.905

The GEN-2024-SR1 project details were used to create modified stability models for this impact study based on the DISIS-2018-002/2019-001 stability study models:

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

The existing EGF configuration in the DISIS-2018-002/2019-001 model has a maximum generator output of 520 MW, which is slightly lower than the attested 524.8 MW. The scenarios being studied for this surplus request did not require the EGF to be dispatched above the modeled 520 MW, so the EGF modeling was not altered for this study.

The dynamic model data for the GEN-2024-SR1 project is provided in Appendix A. The power flow models and associated dynamic 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 surplus request:

- The frequency protective relays at buses 763002, 763002, & 763475 were disabled after observing the generators tripping during initial three phase fault simulations. This frequency

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

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 bus 763002 was disabled to avoid generator tripping due to an instantaneous over voltage spike after fault clearing.
- The PSSE dynamic simulation iterations and acceleration factor were adjusted as needed to resolve PSSE dynamic simulation crashes.

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 4. In addition, voltages of five (5) buses away from the POI of the SGF were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas including 327 (EES-EAI), 330 (AECI), 351 (EES), 356 (AMMO), 502 (CLEC), 515 (SWPA), 520 (AEPW), 523 (GRDA), 524 (OKGE), 525 (WFEC), 526 (SPS), 527 (OMPA), 534 (SUNC), 536 (WERE), 544 (EMDE), and 546 (SPRM) were monitored. The voltages of all 100 kV and above buses within the study area were monitored as well.

5.2 Fault Definitions

Aneden developed fault events as required to study the SGF. The new set of faults was 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 5-2 below. These contingencies were applied to the modified 25SP and 25WP models.

Table 5-2: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT0037-3PH	P1	3 phase fault on the FLINTCK2 345 kV (506935) /161 kV (506934) /13.8 kV (506920) XFMR CKT 2, near FLINTCR7 345 kV. a. Apply fault at the FLINTCR7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT0125-3PH	P1	3 phase fault on the GRDA1 7 (512650) to GREC TAP5 (512865) 345 kV line CKT 1, near GRDA1 7. a. Apply fault at the GRDA1 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.
FLT0152-3PH	P1	3 phase fault on the TONECE7 7 (512750) to GRDA1 7 (512650) 345 kV line CKT 1, near TONECE7 7. a. Apply fault at the TONECE7 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.
FLT0167-3PH	P1	3 phase fault on the IGLOOAUTO1 345 kV (513596) /161 kV (513593) /13.8 kV (513592) XFMR CKT 1, near IGLOOV 7 345 kV. a. Apply fault at the IGLOOV 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9001-3PH	P1	3 phase fault on the GREC TAP5 (512865) to GRDA1 7 (512650) 345 kV line CKT 1, near GREC TAP5. a. Apply fault at the GREC TAP5 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.
FLT9002-3PH	P1	3 phase fault on the GREC TAP5 (512865) to IGLOOV7 (513596) 345 kV line CKT 1, near GREC TAP5. a. Apply fault at the GREC TAP5 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.
FLT9003-3PH	P1	3 phase fault on the GRDA1 7 (512650) to TONECE7 7 (512750) 345 kV line CKT 1, near GRDA1 7. a. Apply fault at the GRDA1 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.
FLT9004-3PH	P1	3 phase fault on the GRDA1 7 (512650) to 7SPORTSMAN (300740) 345 kV line CKT 1, near GRDA1 7. a. Apply fault at the GRDA1 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.
FLT9005-3PH	P1	3 phase fault on the GRDAUTO1 345 kV (512650) /161 kV (512656) /13.8 kV (512821) XFMR CKT 1, near GRDA1 7 345 kV. a. Apply fault at the GRDA1 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9006-3PH	P1	3 phase fault on the GRDA2 345 kV (512650) /22.8 kV (512688) XFMR CKT 1, near GRDA1 7 345 kV. a. Apply fault at the GRDA1 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer. Trip the generator on bus GRDA17-1 (512688)

Table 5-2 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9007-3PH	P1	3 phase fault on the IGLOOV 7 (513596) to T.NO.--7 (509852) 345 kV line CKT 1, near IGLOOV 7. a. Apply fault at the IGLOOV 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.
FLT9008-3PH	P1	3 phase fault on the T.NO.--7 (509852) to CLEVLND7 (512694) 345 kV line CKT 1, near T.NO.--7. a. Apply fault at the T.NO.--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.
FLT9009-3PH	P1	3 phase fault on the T.NO.--7 (509852) to WEKIWA-7 (509755) 345 kV line CKT 1, near T.NO.--7. a. Apply fault at the T.NO.--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.
FLT9010-3PH	P1	3 phase fault on the T.NO.--7 (509852) to N.E.S.-7 (510406) 345 kV line CKT 1, near T.NO.--7. a. Apply fault at the T.NO.--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.
FLT9011-3PH	P1	3 phase fault on the TULSA N 2 345 kV (509852) /138 kV (509895) / 34.5 (509894) XFMR CKT 1, near T.NO.--7 345 kV. a. Apply fault at the T.NO.--7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9012-3PH	P1	3 phase fault on the TONECE7 (512750) to FLINTCR7 (506935) 345 kV line CKT 1, near TONECE7. a. Apply fault at the TONECE7 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.
FLT9013-3PH	P1	3 phase fault on the TONNEC345 345 kV (512750) /161 kV (512751) / 13.2 (512752) XFMR CKT 1, near TONECE7 345 kV. a. Apply fault at the TONECE7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9014-3PH	P1	3 phase fault on the FLINTCR7 (506935) to SHIPERD7 (506979) 345 kV line CKT 1, near FLINTCR7. a. Apply fault at the FLINTCR7 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.
FLT9015-3PH	P1	3 phase fault on the FLINTCR7 (506935) to BROOKLINE 7 (549984) 345 kV line CKT 1, near FLINTCR7. a. Apply fault at the FLINTCR7 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.
FLT9016-3PH	P1	3 phase fault on the 7SPORTSMAN (300740) to 7BLACKBERRY (300739) 345 kV line CKT 1, near 7SPORTSMAN. a. Apply fault at the 7SPORTSMAN 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.
FLT9017-3PH	P1	3 phase fault on the SPORTSMAN1 345 kV (300740) /161 kV (300741) XFMR CKT 1, near 7SPORTSMAN 345 kV. a. Apply fault at the 7SPORTSMAN 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9018-3PH	P1	3 phase fault on the 7BLACKBERRY (300739) to 7JASPER (300949) 345 kV line CKT 1, near 7BLACKBERRY. a. Apply fault at the 7BLACKBERRY 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 5-2 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9019-3PH	P1	3 phase fault on the 7BLACKBERRY (300739) to WOLFCRK7 (532797) 345 kV line CKT 1, near 7BLACKBERRY. a. Apply fault at the 7BLACKBERRY 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.
FLT9020-3PH	P1	3 phase fault on the 7BLACKBERRY (300739) to NEOSHO 7 (532793) 345 kV line CKT 1, near 7BLACKBERRY. a. Apply fault at the 7BLACKBERRY 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.
FLT9021-3PH	P1	3 phase fault on the CTG GSU 345 kV (512865) /20 kV (512614) XFMR CKT 1, near GREC TAP5 345 kV. a. Apply fault at the GREC TAP5 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer. Trip the generator on bus GRECCTG_1 (512614)
FLT9022-3PH	P1	3 phase fault on the STG GSU 345 kV (512865) /21 kV (512615) XFMR CKT 1, near GREC TAP5 345 kV. a. Apply fault at the GREC TAP5 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer. Trip the generator on bus GRECSTG_1 (512615)
FLT9023-3PH	P1	3 Phase fault on 5SPORTSMAN (300741) 161 kV Bus to 5CHOTEAU2 (301348) line CKT 1, near 5SPORTSMAN (300741) 161 kV. a. Apply fault at the 5SPORTSMAN (300741) 161 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 5CHOTEAU2 161 kV (301348) /16 kV (300020) XFMR CKT 21, near 5CHOTEAU2 (301348) 161 kV. a. Apply fault at the 5CHOTEAU2 (301348) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer. Trip generator on the Bus 1CHOTCT4 (300020) 16 kV
FLT9025-3PH	P1	3 Phase fault on 5CHOTEAU2 (301348) 161 kV Bus to 5CHOTEAU1 (300069) 161 kV line CKT Z1, near 5CHOTEAU2 (301348) 161 kV. a. Apply fault at the 5CHOTEAU2 (301348) 161 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.
FLT9026-3PH	P1	3 Phase fault on 5CHOTEAU1 (300069) 161 kV Bus to MAID 5 (512648) 161 kV line CKT 1, near 5CHOTEAU1 (300069) 161 kV. a. Apply fault at the 5CHOTEAU1 (300069) 161 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.
FLT9027-3PH	P1	3 Phase fault on TONECE5 (512751) 161 kV Bus to SILMCTY5 (512643) 161 kV line CKT 1, near TONECE5 (512751) 161 kV. a. Apply fault at the TONECE5 (512751) 161 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 TONECE5 161 kV (512751) /69 kV (512753) /13.2 kV (512754) XFMR CKT 1 , near TONECE5 (512751) 161 kV. a. Apply fault at the TONECE5 (512751) 161 kV Bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9029-3PH	P1	3 Phase fault on SILMCTY5 (512643) 161 kV Bus to SILOAM 5 (506948) 161 kV line CKT 1, near SILMCTY5 (512643) 161 kV. a. Apply fault at the SILMCTY5 (512643) 161 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 5-2 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9030-3PH	P1	3 Phase fault on SILMCTY5 (512643) 161 kV Bus to SILSPWW5 (512642) 161 kV line CKT 1, near SILMCTY5 (512643) 161 kV. a. Apply fault at the SILMCTY5 (512643) 161 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.
FLT9031-3PH	P1	3 Phase fault on SILMCTY5 161 kV (512643) /69 kV (512820) /13.8 kV (512849) XFMR CKT 1, near SILMCTY5 (512643) 161 kV. a. Apply fault at the SILMCTY5 (512643) 161 kV Bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9032-3PH	P1	3 Phase fault on FLINTCR5 161 kV (506934) /22 kV (509394) XFMR CKT 21, near FLINTCR5 (506934) 161 kV. a. Apply fault at the FLINTCR5 (506934) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer. Trip generator on the Bus FLINTCR1 (509394) 22 kV.
FLT9033-3PH	P1	3 Phase fault on FLINTCR5 (506934) 161 kV Bus to SILOAMSP 5 (504202) 161 kV line CKT 1, near FLINTCR5 (506934) 161 kV. a. Apply fault at the FLINTCR5 (506934) 161 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 FLINTCR5 (506934) 161 kV Bus to TONTITN5 (506957) 161 kV line CKT 1, near FLINTCR5 (506934) 161 kV. a. Apply fault at the FLINTCR5 (506934) 161 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 FLINTCR5 (506934) 161 kV Bus to GENTRY 5 (504201) 161 kV line CKT 1, near FLINTCR5 (506934) 161 kV. a. Apply fault at the FLINTCR5 (506934) 161 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 FLINTCR5 (506934) 161 kV Bus to DEC392 5 (547484) 161 kV line CKT 1, near FLINTCR5 (506934) 161 kV. a. Apply fault at the FLINTCR5 (506934) 161 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.
FLT9037-3PH	P1	3 Phase fault on FLINTCR5 (506934) 161 kV Bus to SILOAM 5 (506948) 161 kV line CKT 1, near FLINTCR5 (506934) 161 kV. a. Apply fault at the FLINTCR5 (506934) 161 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.
FLT9038-3PH	P1	3 Phase fault on GRDA1 5 (512656) 161 kV Bus to CLARMR 5 (512651) 161 kV line CKT 1, near GRDA1 5 (512656) 161 kV. a. Apply fault at the GRDA1 5 (512656) 161 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.
FLT9039-3PH	P1	3 Phase fault on GRDA1 5 (512656) 161 kV Bus to WMAIN ST5 (512742) 161 kV line CKT 1, near GRDA1 5 (512656) 161 kV. a. Apply fault at the GRDA1 5 (512656) 161 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.
FLT9040-3PH	P1	3 Phase fault on GRDA1 5 (512656) 161 kV Bus to WAGNOR 5 (512700) 161 kV line CKT 1, near GRDA1 5 (512656) 161 kV. a. Apply fault at the GRDA1 5 (512656) 161 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 5-2 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9041-3PH	P1	3 Phase fault on GRDA1 5 (512656) 161 kV Bus to MAID 5 (512648) 161 kV line CKT 1, near GRDA1 5 (512656) 161 kV. a. Apply fault at the GRDA1 5 (512656) 161 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.
FLT9042-3PH	P1	3 Phase fault on GRDA1 5 161 kV (512656) /69 kV (512727) /13.8 kV (512816) XFMR CKT 1, near GRDA1 5 (512656) 161 kV. a. Apply fault at the GRDA1 5 (512656) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
FLT9043-3PH	P1	3 Phase fault on CLARMR 5 161 kV (512651) /69 kV (512679) /13.8 kV (512814) XFMR CKT 1, near CLARMR 5 (512651) 161 kV. a. Apply fault at the CLARMR 5 (512651) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
FLT9044-3PH	P1	3 Phase fault on CLARMR 161 kV (512651) /69 kV (512813) /13.8 kV (512707) XFMR CKT 1, near CLARMR 5 (512651) 161 kV. a. Apply fault at the CLARMR 5 (512651) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
FLT9045-3PH	P1	3 Phase fault on CLARMR 5 (512651) 161 kV Bus to 5KETONVL (300997) 161 kV line CKT 1, near CLARMR 5 (512651) 161 kV. a. Apply fault at the CLARMR 5 (512651) 161 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.
FLT9046-3PH	P1	3 Phase fault on 5KETONVL (300997) 161 kV Bus to COLINS 5 (512627) 161 kV line CKT 1, near 5KETONVL (300997) 161 kV. a. Apply fault at the 5KETONVL (300997) 161 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.
FLT9047-3PH	P1	3 Phase fault on WMAIN ST5 (512742) 161 kV Bus to GEN-2017-061 (588990) 161 kV line CKT 1, near WMAIN ST5 (512742) 161 kV. a. Apply fault at the WMAIN ST5 (512742) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. Trip generator on the Bus G17-061-GEN1 (588993) 0.7 kV 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.
FLT9048-3PH	P1	3 Phase fault on WMAIN ST5 (512742) 161 kV Bus to NWMAID5 (512757) 161 kV line CKT 1, near WMAIN ST5 (512742) 161 kV. a. Apply fault at the WMAIN ST5 (512742) 161 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.
FLT9049-3PH	P1	3 Phase fault on NWMAID5 (512757) 161 kV Bus to GERALDGAY5 (512760) 161 kV line CKT 1, near NWMAID5 (512757) 161 kV. a. Apply fault at the NWMAID5 (512757) 161 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.
FLT9050-3PH	P1	3 Phase fault on WAGNOR 5 (512700) 161 kV Bus to OKAYGR 5 (512640) 161 kV line CKT 1, near WAGNOR 5 (512700) 161 kV. a. Apply fault at the WAGNOR 5 (512700) 161 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.
FLT9051-3PH	P1	3 Phase fault on WAGNOR 5 161 kV (512700) /69 kV (512697) /13.8 kV (512818) XFMR CKT 1, near WAGNOR 5 (512700) 161 kV. a. Apply fault at the WAGNOR 5 (512700) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.

Table 5-2 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9052-3PH	P1	3 Phase fault on OKAYGR 5 (512640) 161 kV Bus to FT GIB 5 (505560) 69 kV line CKT 1, near OKAYGR 5 (512640) 161 kV. a. Apply fault at the OKAYGR 5 (512640) 161 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.
FLT9053-3PH	P1	3 Phase fault on OKAYGR 5 161 kV (512640) /69 kV (512646) /13.8 kV (512848) XFMR CKT 1, near OKAYGR 5 (512640) 161 kV. a. Apply fault at the OKAYGR 5 (512640) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
FLT9054-3PH	P1	3 Phase fault on MAID 5 (512648) 161 kV Bus to CATSAGR5 (512638) 161 kV line CKT 1, near MAID 5 (512648) 161 kV. a. Apply fault at the MAID 5 (512648) 161 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.
FLT9055-3PH	P1	3 Phase fault on MAID 5 161 kV (512648) /69 kV (512626) /13.8 kV (512836) XFMR CKT 1, near MAID 5 (512648) 161 kV. a. Apply fault at the MAID 5 (512648) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
FLT9056-3PH	P1	3 Phase fault on MAID 5 (512648) 161 kV Bus to DRYGULCH5 (512629) 161 kV line CKT 1, near MAID 5 (512648) 161 kV. a. Apply fault at the MAID 5 (512648) 161 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.
FLT9057-3PH	P1	3 Phase fault on MAID 5 (512648) 161 kV Bus to KERR GR5 (512635) 161 kV line CKT 1, near MAID 5 (512648) 161 kV. a. Apply fault at the MAID 5 (512648) 161 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.
FLT9058-3PH	P1	3 Phase fault on MAID 5 (512648) 161 kV Bus to GEN-2019-002 (763472) 161 kV line CKT 1, near MAID 5 (512648) 161 kV. a. Apply fault at the MAID 5 (512648) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. Trip generator on the Bus G19-002-GEN1 (763475) 0.7 kV 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.
FLT9059-3PH	P1	3 Phase fault on MAID 5 (512648) 161 kV Bus to LOCSTGVKM 5 (513050) 161 kV line CKT 1, near MAID 5 (512648) 161 kV. a. Apply fault at the MAID 5 (512648) 161 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.
FLT9060-3PH	P1	3 Phase fault on LOCSTGVKM 5 (513050) 161 kV Bus to 5CDRCRST (301344) 161 kV line CKT 1, near LOCSTGVKM 5 (513050) 161 kV. a. Apply fault at the LOCSTGVKM 5 (513050) 161 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.
FLT9061-3PH	P1	3 Phase fault on CATSAGR5 (512638) 161 kV Bus to 5ELMCRK (300993) 161 kV line CKT 1, near CATSAGR5 (512638) 161 kV. a. Apply fault at the CATSAGR5 (512638) 161 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.
FLT9062-3PH	P1	3 Phase fault on CATSAGR5 161 kV (512638) /69 kV (509790) /13.8 kV (512833) XFMR CKT 1, near CATSAGR5 (512638) 161 kV. a. Apply fault at the CATSAGR5 (512638) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.

Table 5-2 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9063-3PH	P1	3 Phase fault on KERR GR5 (512635) 161 kV Bus to PENSA 5 (512654) 161 kV line CKT 1, near KERR GR5 (512635) 161 kV. a. Apply fault at the KERR GR5 (512635) 161 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.
FLT9064-3PH	P1	3 Phase fault on KERR GR5 (512635) 161 kV Bus to 412SUB 5 (512637) 161 kV line CKT 1, near KERR GR5 (512635) 161 kV. a. Apply fault at the KERR GR5 (512635) 161 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.
FLT9065-3PH	P1	3 Phase fault on KERR GR5 (512635) 161 kV Bus to SALNCRK5 (512805) 161 kV line CKT 1, near KERR GR5 (512635) 161 kV. a. Apply fault at the KERR GR5 (512635) 161 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.
FLT9066-3PH	P1	3 Phase fault on KERR GR5 (512635) 161 kV Bus to KERR BRK1 5 (512770) 161 kV line CKT Z0, near KERR GR5 (512635) 161 kV. a. Apply fault at the KERR GR5 (512635) 161 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.
FLT9067-3PH	P1	3 Phase fault on KERR BRK1 5 161 kV (512770) /69 kV (512634) /13.8 kV (512846) XFMR CKT 1, near KERR BRK1 5 (512770) 161 kV. a. Apply fault at the KERR BRK1 5 (512770) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
FLT1001-SB	P4	**Stuck Breaker at GRDA1 7 (512650) 345 kV bus** a. Apply single phase fault at GRDA1 7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the GRDA1 7 (512650) to TONECE7 7 (512750) 345 kV line CKT 1. d. Trip the GRDAUTO1 345 kV (512650) /161 kV (512656) /13.8 kV (512821) XFMR CKT 1.
FLT1002-SB	P4	**Stuck Breaker at GRDA1 7 (512650) 345 kV bus** a. Apply single phase fault at GRDA1 7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the GRDA1 7 (512650) to TONECE7 7 (512750) 345 kV line CKT 1. d. Trip the GRDAUTO1 345 kV (512650) /161 kV (512656) /13.8 kV (512826) XFMR CKT 2.
FLT1003-SB	P4	**Stuck Breaker at GRDA1 7 (512650) 345 kV bus** a. Apply single phase fault at GRDA1 7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the GRDA1 7 (512650) to 7SPORTSMAN (300740) 345 kV line CKT 1. d. Trip the GRDAUTO1 345 kV (512650) /161 kV (512656) /13.8 kV (512821) XFMR CKT 1.
FLT1004-SB	P4	**Stuck Breaker at GRDA1 7 (512650) 345 kV bus** a. Apply single phase fault at GRDA1 7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the GRDA1 7 (512650) to 7SPORTSMAN (300740) 345 kV line CKT 1. d. Trip the GRDAUTO1 345 kV (512650) /161 kV (512656) /13.8 kV (512826) XFMR CKT 2.
FLT1005-SB	P4	**Stuck Breaker at GRDA1 7 (512650) 345 kV bus** a. Apply single phase fault at GRDA1 7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the GRDA1 7 (512650) to GREC TAP5 (512865) 345 kV line CKT 1. d. Trip the GRDAUTO1 345 kV (512650) /161 kV (512656) /13.8 kV (512821) XFMR CKT 1.
FLT1006-SB	P4	Stuck Breaker at GRDA1 7 (512650) 345 kV bus a. Apply single phase fault at GRDA1 7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the GRDA2 345 kV (512650) /22.8 kV (512688) XFMR CKT 1. d. Trip the GRDAUTO1 345 kV (512650) /161 kV (512656) /13.8 kV (512826) XFMR CKT 2. Trip the generator on bus GRDA17-1 (512688)

Table 5-2 Continued

Fault ID	Planning Event	Fault Descriptions
FLT1007-SB	P4	Stuck Breaker at GRDA1 7 (512650) 345 kV bus a. Apply single phase fault at GRDA1 7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the GRDA2 345 kV (512650) /22.8 kV (512688) XFMR CKT 1. d. Trip the GRDA1 7 (512650) to GREC TAP5 (512865) 345 kV line CKT 1. Trip the generator on bus GRDA17-1 (512688)
FLT1008-SB	P4	Stuck Breaker at IGLOOV7 (513596) 345 kV bus a. Apply single phase fault at IGLOOV7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the IGLOOV7 (513596) to GREC TAP5 (512865) 345 kV line CKT 1. d. Trip the IGLOOAUTO1 345 kV (513596) /161 kV (513593) /13.8 kV (513592) XFMR CKT 1.
FLT1009-SB	P4	**Stuck Breaker at IGLOOV7 (513596) 345 kV bus** a. Apply single phase fault at IGLOOV7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the IGLOOV 7 (513596) to T.NO.--7 (509852) 345 kV line CKT 1. d. Trip the IGLOOAUTO1 345 kV (513596) /161 kV (513593) /13.8 kV (513592) XFMR CKT 1.
FLT1010-SB	P4	**Stuck Breaker at IGLOOV7 (513596) 345 kV bus** a. Apply single phase fault at IGLOOV7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the IGLOOV7 (513596) to GREC TAP5 (512865) 345 kV line CKT 1. d. Trip the IGLOOAUTO1 345 kV (513596) /161 kV (513595) /13.8 kV (513594) XFMR CKT 2.
FLT1011-SB	P4	**Stuck Breaker at IGLOOV7 (513596) 345 kV bus** a. Apply single phase fault at IGLOOV7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the IGLOOV 7 (513596) to T.NO.--7 (509852) 345 kV line CKT 1. d. Trip the IGLOOAUTO1 345 kV (513596) /161 kV (513595) /13.8 kV (513594) XFMR CKT 2.
FLT1012-SB	P4	**Stuck Breaker at TONECE7 (512750) 345 kV bus** a. Apply single phase fault at TONECE7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the bus TONECE7 (512750)
FLT1013-SB	P4	**Stuck Breaker at GREC TAP5 (512865) 345 kV bus** a. Apply single phase fault at GREC TAP5 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the GREC TAP5 (512865) to IGLOOV7 (513596) 345 kV line CKT 1. d. Trip the CTG GSU 345 kV (512865) /20 kV (512614) XFMR CKT 1. e. Trip the STG GSU 345 kV (512865) /21 kV (512615) XFMR CKT 1. Trip the generator on bus GRECCTG_1 (512614) Trip the generator on bus GRECSTG_1 (512615)
FLT1014-SB	P4	**Stuck Breaker at 7SPORTSMAN (300740) 345 kV bus** a. Apply single phase fault at 7SPORTSMAN bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the 7SPORTSMAN (300740) to 7BLACKBERRY (300739) 345 kV line CKT 1. d. Trip the SPORTSMAN1 345 kV (300740) /161 kV (300741) XFMR CKT 1.
FLT1015-SB	P4	**Stuck Breaker at 7SPORTSMAN (300740) 345 kV bus** a. Apply single phase fault at 7SPORTSMAN bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the 7SPORTSMAN (300740) to GRDA1 7 (512650) 345 kV line CKT 1. d. Trip the SPORTSMAN1 345 kV (300740) /161 kV (300741) XFMR CKT 1.
FLT1016-SB	P4	**Stuck Breaker at 7SPORTSMAN (300740) 345 kV bus** a. Apply single phase fault at 7SPORTSMAN bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the 7SPORTSMAN (300740) to GRDA1 7 (512650) 345 kV line CKT 1. d. Trip the SPORTSMAN1 345 kV (300740) /161 kV (300741) XFMR CKT 2.
FLT1017-SB	P4	**Stuck Breaker at 7SPORTSMAN (300740) 345 kV bus** a. Apply single phase fault at 7SPORTSMAN bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the 7SPORTSMAN (300740) to 7BLACKBERRY (300739) 345 kV line CKT 1. d. Trip the SPORTSMAN1 345 kV (300740) /161 kV (300741) XFMR CKT 2.

5.3 Scenario 1 Results

Table 5-3 shows the relevant results of the fault events simulated for each of the modified models in Scenario 1. Existing DISIS base case issues are documented separately in Appendix C. The associated stability plots are also provided in Appendix C.

Table 5-3: Scenario 1 Dynamic Stability Results (EGF = 0 MW, SGF = 83.605 MW)

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT0037-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT0125-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT0152-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT0167-3PH	Pass	Pass	Stable	Pass	Pass	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
FLT9004-3PH	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

Table 5-3 Continued

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	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
FLT9037-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9038-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9039-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9040-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9041-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9042-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9043-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9044-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9045-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9046-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9047-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9048-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9049-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9050-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9051-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9052-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9053-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9054-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9055-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9056-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9057-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9058-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9059-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9060-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9061-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9062-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9063-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9064-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9065-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9066-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9067-3PH	Pass	Pass	Stable	Pass	Pass	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

Table 5-3 Continued

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	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
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1011-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1012-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1013-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1014-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1015-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1016-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1017-SB	Pass	Pass	Stable	Pass	Pass	Stable

The results of the Scenario 1 dynamic stability showed several existing base case issues that were found in both the original DISIS-2018-002/2019-001 model and the model with GEN-2024-SR1 included. These issues were not attributed to the GEN-2024-SR1 surplus request and detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2024-SR1 surplus 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.

5.4 Scenario 2 Results

shows the relevant results of the fault events simulated for each of the modified models in Scenario 2. Existing DISIS base case issues are documented separately in Appendix C. The associated stability plots are also provided in Appendix C.

Table 5-4: Scenario 2 Dynamic Stability Results (EGF = 442.3 MW, SGF = 83.605 MW)

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT0037-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT0125-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT0152-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT0167-3PH	Pass	Pass	Stable	Pass	Pass	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
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable

Table 5-4 Continued

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	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
FLT9037-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9038-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9039-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9040-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9041-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9042-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9043-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9044-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9045-3PH	Pass	Pass	Stable	Pass	Pass	Stable

Table 5-4 Continued

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT9046-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9047-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9048-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9049-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9050-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9051-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9052-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9053-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9054-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9055-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9056-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9057-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9058-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9059-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9060-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9061-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9062-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9063-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9064-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9065-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9066-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9067-3PH	Pass	Pass	Stable	Pass	Pass	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
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1011-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1012-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1013-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1014-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1015-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1016-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1017-SB	Pass	Pass	Stable	Pass	Pass	Stable

The results of the Scenario 2 dynamic stability showed several existing base case issues that were found in both the original DISIS-2018-002/2019-001 model and the model with GEN-2024-SR1 included. These issues were not attributed to the GEN-2024-SR1 surplus request and detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2024-SR1 surplus 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.

6.0 Necessary Interconnection Facilities and Network Upgrades

This study identified the impact of the Surplus Interconnection Service on the transmission system reliability and any additional Interconnection Facilities or Network Upgrades necessary. The Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades unless (a) those additional Network Upgrades are either (1) located at the Point of Interconnection substation and at the same voltage level as the Generating Facility with an effective GIA, or (2) are System Protection Facilities; and (b) there are no material adverse impacts on the cost or timing of any Interconnection Requests pending at the time the Surplus Interconnection Service request is submitted.

6.1 Interconnection Facilities

This study did not identify any additional Interconnection Facilities required by the addition of the SGF. SPP will reach out to the TO and/or TOP to determine if there are any additional Interconnection Facilities required.

6.2 Network Upgrades

This study did not identify any Network Upgrades required by the addition of the SGF. SPP will reach out to the TO and/or TOP to determine if there are any additional Network Upgrades that are either (1) located at the Point of Interconnection substation and at the same voltage level as the Generating Facility with an effective GIA, or (2) are System Protection Facilities.

7.0 Surplus Interconnection Service Determination and Requirements

In accordance with Attachment V of the SPP Tariff, SPP shall evaluate the request for Surplus Interconnection Service and inform the Interconnection Customer in writing of whether the Surplus Interconnection Service can be utilized without negatively impacting the reliability of the Transmission System and without any additional Network Upgrades necessary except those specified in the SPP Tariff.

7.1 Surplus Service Determination

SPP determined the request for Surplus Interconnection Service does not negatively impact the reliability of the Transmission System and no required Network Upgrades or Interconnection Facilities were identified by this Surplus Interconnection Service Impact Study performed by Aneden. Aneden evaluated the impact of the requested Surplus Interconnection Service on the prior study results and determined that the requested Surplus Interconnection Service resulted in similar dynamic stability and short circuit analyses and that the prior study steady-state results are not negatively impacted.

SPP has determined that GEN-2024-SR1 may utilize the requested 84 MW of Surplus Interconnection Service being made available by GREC 2.

7.2 Surplus Service Requirements

The amount of Surplus Interconnection Service available to be used is limited by the amount of Interconnection Service granted to the existing interconnection customer at the same POI. The combined generation from both the SGF and the EGF may not exceed 524.8 MW at the POI, which is the total Interconnection Service amount currently granted to the EGF.

The customer must install monitoring and control equipment as needed to ensure that the SGF does not exceed the granted surplus amount and to ensure that combination of the SGF and EGF power injected at the POI does not exceed the EGF’s Interconnection Service amount. The monitoring and control scheme may be reviewed by the TO and documented in Appendix C of the SGF GIA.

SPP will reach out to the TO and/or TOP to determine if there are any additional Network Upgrades that are either (1) located at the Point of Interconnection substation and at the same voltage level as the Generating Facility with an effective GIA, or (2) are System Protection Facilities.