Report on

GEN-2023-SR15
Surplus Service Impact Study

Revision R1 June 26, 2023

Submitted to
Southwest Power Pool

SPP Southwest Power Pool

anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
6/26/2023	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-2023-SR15 to utilize the Surplus Interconnection Service being made available by the GEN-2017-023 at its existing Point of Interconnection (POI), the Hugo Power Plant 138 kV Substation in the Western Farmers Electric Cooperative (WFEC) control area.

GEN-2023-SR15, the proposed Surplus Generating Facility (SGF), will connect to the existing GEN-2017-023 main collection substation and share its main power transformer.

GEN-2017-023, the Existing Generating Facility (EGF), has an effective Generator Interconnection Agreement (GIA) with a POI capacity of 85 MW and is making 50 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 11 x Sungrow SC5000UD Battery Energy Storage System (BESS) inverters operating at 4.7345 MW for a total assumed dispatch of 52.08 MW. The inverters are rated at 5 MW, thus the generating capability of the SGF (55 MW) exceeds its requested Surplus Interconnection Service of 50 MW. The injection amount of the SGF must be limited to 50 MW at the POI. The combined generation from both the SGF and the EGF may not exceed 85 MW at the POI. GEN-2023-SR15 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-2023-SR15 (SGF)	50	Battery/Storage	Hugo Power Plant 138 kV Substation (520948)
GEN-2017-023 (EGF)	85	Solar	Hugo Power Plant 138 kV Substation (520948)

[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	Hugo Power Plant 138 kV Substation (520948)
Configuration/Capacity	11 x Sungrow SC5000UD 4.7345 MW (BESS) = 52.08 MW [dispatch] Units are rated at 5 MW, PPC to limit GEN-2023-SR15 to 50 MW at the POI and total POI injection w/ GEN-2017-023 to 85 MW
Generation Interconnection Line (Shared with the EGF and unchanged)	Length = 0.6 miles R = 0.000528 pu X = 0.002290 pu B = 0.000681 pu Rating MVA = 137 MVA
Main Substation Transformer[1] (Shared with the EGF and unchanged)	X = 8.996%, R = 0.279%, Winding MVA = 80 MVA, Rating MVA = 133.3 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 11 X = 5.706%, R = 0.71%, Winding MVA = 55 MVA, Rating MVA = 55 MVA
Equivalent Collector Line[2]	R = 0.001358 pu X = 0.001175 pu B = 0.000477 pu
Auxiliary Load	1.568 MW + 0.515 MVAr on 34.5 kV bus
Generator Dynamic Model[3] & Power Factor	11 x Sungrow SC5000UD 5 MVA (REGCAU1)[3] Leading: 0.947 Lagging: 0.947
Reactive Power Devices (Shared with the EGF and unchanged)	1 x 9 MVAR 34.5 kV Capacitor Bank

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

SPP determined that steady-state analysis was not required because the addition of the SGF does not increase the maximum POI output of 85 MW. In addition, the EGF was previously studied at maximum Interconnection Service under all necessary reliability conditions.

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-2017-002-1 study models:

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

Aneden reviewed Generation Interconnection Requests (GIRs) that shared the same POI, Hugo Power Plant 138 kV, and updated their models as applicable based on SPP's confirmation of the latest project configurations. As a result, Aneden updated the GEN-2017-023 (EGF) project configurations in the base models.

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 did not need a shunt reactor at the project substation to reduce the POI MVAr to zero when the EGF project had a shunt compensating for its charging effects. No additional compensation was necessary to offset the capacitive effect on the transmission network caused by the project 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.

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 0.24 kA. The maximum three-phase fault current level within 5 buses of the POI with the EGF and SGF generators online was below 41 kA for the 25SP model. There was a bus with a maximum three-phase fault current over 40 kA. This bus is 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. 62 events were simulated, which included three-phase faults and single-line-to-ground stuck breaker faults.

- Scenario 1: SGF at maximum assumed dispatch, 52.08 MW, and EGF disconnected.
- Scenario 2: SGF at maximum assumed dispatch, 52.08 MW, and EGF dispatched with the remaining 35.28 MW for a total combination of 87.36 MW (limited to 85 MW at the POI).

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 in the model with GEN-2023-SR15 included. These issues were not attributed to the GEN-2023-SR15 surplus request and are detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2023-SR15 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-2023-SR15 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-2023-SR15 may utilize the requested 50 MW of Surplus Interconnection Service being made available by the EGF. The combined generation from both the SGF and the EGF may not exceed 85 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

[2] Power System Simulator for Engineering

the POI does not exceed the Interconnection Service amount listed in the EGF's GIA. 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, both the SGF and EGF 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-2023-SR15, 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, and the EGF project had a shunt compensating for its charging effects.

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 GIA 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

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

Interconnection Service, both off-peak and peak analysis may need to be performed for the EGF associated with the request.

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-2023-SR15 Interconnection Customer has requested a Surplus Interconnection Service Impact Study (Study) for GEN-2023-SR15 to utilize the Surplus Interconnection Service being made available by GEN-2017-023 at its existing Point of Interconnection (POI), the Hugo Power Plant 138 kV Substation in the Western Farmers Electric Cooperative (WFEC) control area.

GEN-2023-SR15, the proposed SGF, will connect to the existing GEN-2017-023 main collection substation and share its main power transformer.

GEN-2017-023, the EGF, has an effective Generation Interconnection Agreement (GIA) with a POI capacity of 85 MW and is making 50 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, GEN-2017-023 (EGF) is an active existing generator at the same POI (Hugo Power Plant 138 kV Substation) with a queue status of "IA FULLY EXECUTED/ON SCHEDULE". GEN-2017-023 is a solar farm, has a maximum summer and winter queue capacity of 85 MW, and has Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). The EGF was originally studied in the DISIS-2017-001 cluster study. Figure 2-1 shows the power flow model single line diagram for the EGF configuration.

The proposed SGF configuration consists of 11 x Sungrow SC5000UD Battery Energy Storage System (BESS) inverters operating at 4.7345 MW for a total assumed dispatch of 52.08 MW. The inverters are rated at 5 MW, thus the generating capability of the SGF (55 MW) exceeds its requested Surplus Interconnection Service of 50 MW. The injection amount of the SGF must be limited to 50 MW at the POI. The combined generation from both the SGF and the EGF may not exceed 85 MW at the POI. GEN-2023-SR15 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.

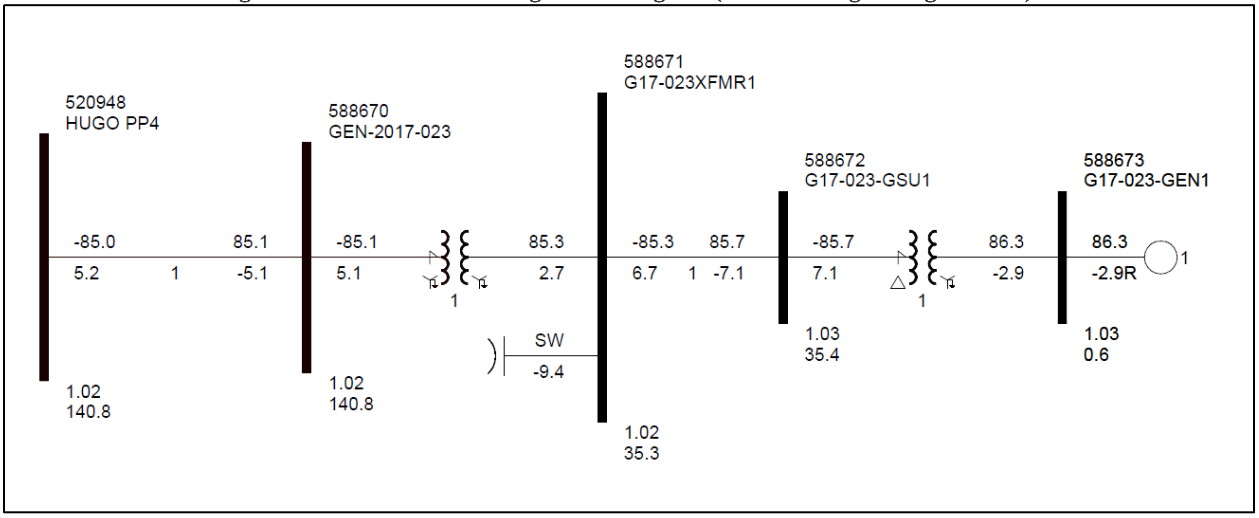
Table 2-1: EGF & SGF Configuration

Request	Interconnection Queue Capacity (MW)	Fuel Type	Point of Interconnection
GEN-2023-SR15 (SGF)	50	Battery/Storage	Hugo Power Plant 138 kV Substation (520948)
GEN-2017-023 (EGF)	85	Solar	Hugo Power Plant 138 kV Substation (520948)

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

Aneden reviewed Generation Interconnection Requests (GIRs) that shared the same POI, Hugo Power Plant 138 kV, and updated their models as applicable based on SPP's confirmation of the latest project configurations. As a result, Aneden updated the GEN-2017-023 (EGF) project configuration in the base models.

Figure 2-1: GEN-2017-023 Single Line Diagram (EGF Existing Configuration*)



*based on the DISIS-2017-002-1 25SP stability models with GEN-2017-023 modeling corrections

Figure 2-2: GEN-2017-023 & GEN-2023-SR15 Single Line Diagram (EGF & SGF Configuration)

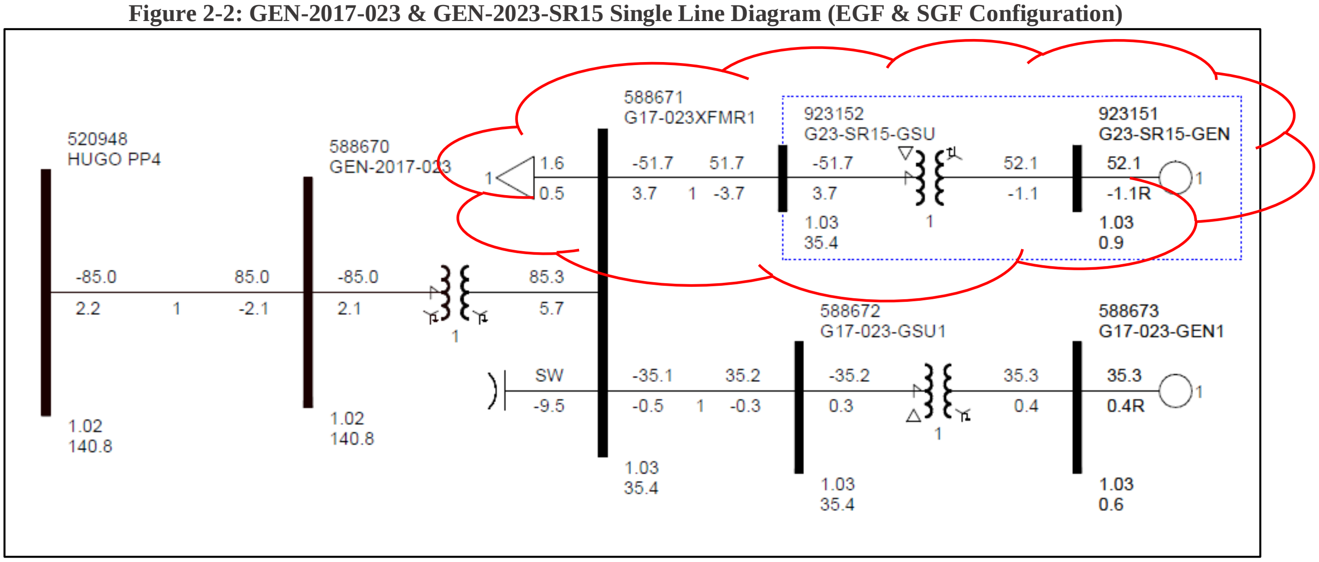


Table 2-2: SGF Interconnection Configuration

Facility	SGF Configuration
Point of Interconnection	Hugo Power Plant 138 kV Substation (520948)
Configuration/Capacity	11 x Sungrow SC5000UD 4.7345 MW (BESS) = 52.08 MW [dispatch] Units are rated at 5 MW, PPC to limit GEN-2023-SR15 to 50 MW at the POI and total POI injection w/ GEN-2017-023 to 85 MW
Generation Interconnection Line (Shared with the EGF and unchanged)	Length = 0.6 miles R = 0.000528 pu X = 0.002290 pu B = 0.000681 pu Rating MVA = 137 MVA
Main Substation Transformer[1] (Shared with the EGF and unchanged)	X = 8.996%, R = 0.279%, Winding MVA = 80 MVA, Rating MVA = 133.3 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 11 X = 5.706%, R = 0.71%, Winding MVA = 55 MVA, Rating MVA = 55 MVA
Equivalent Collector Line[2]	R = 0.001358 pu X = 0.001175 pu B = 0.000477 pu
Auxiliary Load	1.568 MW + 0.515 MVAr on 34.5 kV bus
Generator Dynamic Model[3] & Power Factor	11 x Sungrow SC5000UD 5 MVA (REGCAU1)[3] Leading: 0.947 Lagging: 0.947
Reactive Power Devices (Shared with the EGF and unchanged)	1 x 9 MVAR 34.5 kV Capacitor Bank

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

3.0 Reactive Power Analysis

The reactive power analysis was performed for GEN-2023-SR15 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

In order to determine the shunt reactor size required to compensate for the current charging attributed to the SGF collection system, the reactive power analysis for the EGF was determined first. Once the shunt size for the EGF was determined, the SGF incremental shunt reactor size was then calculated.

For each of the shunt reactor sizes calculated, all project generators, auxiliary/station service loads, and capacitors were switched offline while other collector system elements remained in-service. For the SGF reactor size calculation, the EGF generators were also switched offline. 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 SGF data based on the 25SP DISIS-2017-002-1 stability study model.

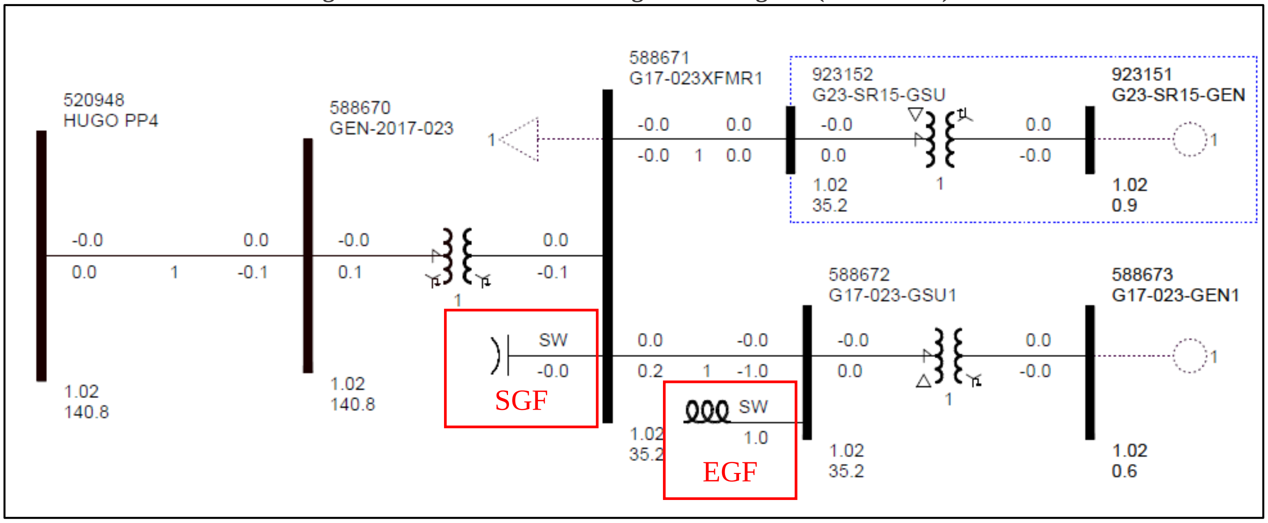
3.2 Results

Per the methodology described above, the shunt size was determined for the EGF prior to calculating the shunt reactor size for the SGF. The shunt size was found to be a 1.0 MVAr reactor for the EGF to reduce the POI MVAr to approximately zero. Note that the EGF shunt value is for the SGF reactive size determination only and not for sizing the predetermined EGF reactive requirements.

The results from the analysis showed that the SGF did not need a shunt reactor at the project substation to reduce the POI MVAr to zero with the pre-determined shunt for the EGF in-service. Figure 3-1 illustrates that no additional compensation was necessary to offset the capacitive effect on the transmission network caused by the project 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.

Figure 3-1: GEN-2023-SR15 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 138 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-2017-002-1 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#
	923151
Machine MVA Base	55
R (pu)	0.0
X'' (pu)	0.84111

*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-2023-SR15 POI bus (Hugo Power Plant 138 kV - 520948) fault current magnitudes for the comparison cases are provided in Table 4-2 showing a fault current of 22.62 kA with the EGF and SGF online. The addition of the SGF configuration increased the POI bus fault current by 0.24 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 less than 41 kA for the 25SP model. There was a bus with a maximum three-phase fault current over 40 kA. This bus is highlighted in Appendix B. The maximum contribution to three-phase fault currents due to the addition of the SGF was about 1.1% and 0.24 kA.

Table 4-2: POI Short Circuit Comparison Results

Case	EGF Only Current (kA)	SGF & EGF Current (kA)	Max kA Change	Max %Change
25SP	22.38	22.62	0.24	1.1%

Table 4-3: 25SP Short Circuit Comparison Results

Voltage (kV)	Max. Current (EGF & SGF) (kA)	Max kA Change	Max %Change
69	7.3	0.00	0.1%
138	40.8	0.24	1.1%
345	28.7	0.04	0.4%
Max	**40.8**	**0.24**	**1.1%**

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 11 x Sungrow SC5000UD operating at 4.7345 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-2017-002-1. The first scenario (Scenario 1) was comprised of the SGF online at 100% of the assumed dispatch (SGF = 52.08 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 = 52.08 MW) while the EGF generator picked up the remaining EGF capacity with the POI injection not exceeding 85 MW (EGF = 35.28 MW). The study scenarios are shown in Table 5-1.

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

Scenario	GEN-2017-023 EGF (MW)	GEN-2023-SR15 SGF (MW)	EGF + SGF (MW)
1	0 (Offline)	52.08	52.08
2	35.28	52.08	87.36

The GEN-2023-SR15 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)

Aneden reviewed the GIRs that shared the same POI, Hugo Power Plant 138 kV, and updated as applicable based on SPP's confirmation of the latest project configurations. As a result, Aneden updated the GEN-2017-023 (EGF) project configuration in the base models.

The dynamic model data for the GEN-2023-SR15 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 599117, 515551, 599119, 599120, 515882, 515883, 515664, & 515665 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.

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

- The voltage protective relays at buses 515969, 515968, 515967, 515986, 515985, 515984, 587953, 587953, 539852, 539853, 539845, 539846, 539847, 539848, 515664, 515665, 588713, 588714, 588715, & 588716 were disabled to avoid generator tripping due to an instantaneous over voltage spike after fault clearing.
- The fault simulation file acceleration factor was reduced as needed to resolve stability 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 their cluster group[6]. 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 330 (AECI), 515 (SWPA), 520 (AEPW), 523 (GRDA), 524 (OKGE), 525 (WFEC), 527 (OMPA), and 534 (SUNC) 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 and simulated 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
FLT9001-3PH	P1	3 phase fault on the HUGO PP4 (520948) to SAWYER4 (520411) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV 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 HUGO PP4 (520948) to FROGVIL4 (520918) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV 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 YNd1 138kV (520948) / 23.4kV (520947) XFMR CKT 1, near HUGO PP4 (520948) 138kV. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted transformer. Trip the generator HUGO1 (520947).
FLT9004-3PH	P1	3 phase fault on the HUGO PP4 (520948) to VALLANT4 (521079) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV 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.

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

Table 5-2 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9005-3PH	P1	3 phase fault on the HUGO PP4 (520948) to HUGOITC4 (520560) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV 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.
FLT9006-3PH	P1	3 phase fault on the HUGO PP4 (520948) to VALIANT4 (510918) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV 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.
FLT9007-3PH	P1	3 phase fault on the HUGO 1 138kV (520560) / 345 kV (521157)/ 13.8 kV (521189) XFMR CKT 1, near HUGOITC4 (520560) 138kV. a. Apply fault at the HUGOITC4 138kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9008-3PH	P1	3 phase fault on the SAWYER4 (520411) to RATTAN 4 (521036) 138kV line CKT 1, near SAWYER4. a. Apply fault at the SAWYER4 138kV 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 FROGVIL4 (520918) to WSBNKTP4 (521098)138kV line CKT 1, near FROGVIL4. a. Apply fault at the FROGVIL4 138kV 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 RATTAN 4 (521036) to DARWIN 4 (520874) 138kV line CKT 1, near RATTAN 4. a. Apply fault at the RATTAN 4 138kV 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 WSBNKTP4 (521098) to UNGER 4 (521077) 138kV line CKT 1, near WSBNKTP4. a. Apply fault at the WSBNKTP4 138kV 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.
FLT9012-3PH	P1	3 phase fault on the VALLANT4 (521079) to GARVIN4 (520419) 138kV line CKT 1, near VALLANT4. a. Apply fault at the VALLANT4 138kV 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 GARVIN4 (520419) to IDABEL 4 (520953) 138kV line CKT 1, near GARVIN4. a. Apply fault at the GARVIN4 138kV 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 HUGO 7 (521157) to G16-063-TAP (560088) 345 kV line CKT 1, near HUGO 7. a. Apply fault at the HUGO 7 138kV 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 HUGO 7 (521157) to VALIANT7 (510911) 345 kV line CKT 1, near HUGO 7. a. Apply fault at the HUGO 7 138kV 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 VALIANT3 138kV (510918) / 345 kV (510911)/ 13.8 kV (510939) XFMR CKT 1, near VALIANT4 (510918) 138kV. a. Apply fault at the VALIANT4 138kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.

Table 5-2 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9017-3PH	P1	3 phase fault on the VALIANT2 138kV (510918) / 69 kV (510910)/ 13.8 kV (510937) XFMR CKT 1, near VALIANT4 (510918) 138kV. a. Apply fault at the VALIANT4 138kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9018-3PH	P1	3 phase fault on the VALIANT4 (510918) to V-WEYCO4 (510866) 138kV line CKT 1, near VALIANT4. a. Apply fault at the VALIANT4 138kV 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 VALIANT4 (510918) to IDABEL-4 (510886) 138kV line CKT 1, near VALIANT4. a. Apply fault at the VALIANT4 138kV 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 VALIANT4 (510918) to HUGO-4 (510901) 138kV line CKT 1, near VALIANT4. a. Apply fault at the VALIANT4 138kV 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 IDABEL-4 (510886) to B.BOWTP4 (510888) 138kV line CKT 1, near IDABEL-4. a. Apply fault at the IDABEL-4 138kV 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.
FLT9022-3PH	P1	3 phase fault on the HUGO 138kV (510901) /69 kV (510893)/ 13.8 kV (510859) XFMR CKT 1, near VALIANT4 (510918) 138kV. a. Apply fault at the VALIANT4 138kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9023-3PH	P1	3 phase fault on the G16-063-TAP (560088) to GEN-2017-075 (589130) 345 kV line CKT 1, near G16-063-TAP. a. Apply fault at the G16-063-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip the generator G17-075-GEN1 (589133).** 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.
FLT9024-3PH	P1	3 phase fault on the G16-063-TAP (560088) to GEN-2016-063 (587430) 345 kV line CKT 1, near G16-063-TAP. a. Apply fault at the G16-063-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip the generators G16-063-GEN1 (587433), G16-063-GEN2 (587436).** 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.
FLT9025-3PH	P1	3 phase fault on the G16-063-TAP (560088) to SUNNYSD7 (515136) 345 kV line CKT 1, near G16-063-TAP. a. Apply fault at the G16-063-TAP 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.
FLT9026-3PH	P1	3 phase fault on the VALIANT7 (510911) to PITTSB-7 (510907) 345 kV line CKT 1, near VALIANT7. a. Apply fault at the VALIANT7 138kV 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.
FLT9027-3PH	P1	3 phase fault on the VALIANT7 (510911) to NWTXARK7 (508072) 345 kV line CKT 1, near VALIANT7. a. Apply fault at the VALIANT7 138kV 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
FLT9028-3PH	P1	3 phase fault on the VALIANT7 (510911) to LYDIA 7 (508298) 345 kV line CKT 1, near VALIANT7. a. Apply fault at the VALIANT7 138kV 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.
FLT9029-3PH	P1	3 phase fault on the LYDIA 7 (508298) to NWTXARK7 (508072) 345 kV line CKT 1, near LYDIA 7. a. Apply fault at the LYDIA 7 138kV 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.
FLT9030-3PH	P1	3 phase fault on the LYDIA 7 (508298) to WELSH 7 (508359) 345 kV line CKT 1, near LYDIA 7. a. Apply fault at the LYDIA 7 138kV 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.
FLT9031-3PH	P1	3 phase fault on the SUNNYSD2 345 kV (515136) /138kV (515135)/ 13.8 kV (515405) XFMR CKT 1, near SUNNYSD7 (515136) 345 kV. a. Apply fault at the SUNNYSD7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9032-3PH	P1	3 phase fault on the SUNNYSD2 345 kV (515136) /138kV (515135)/ 13.8 kV (515762) XFMR CKT 1, near SUNNYSD7 (515136) 345 kV. a. Apply fault at the SUNNYSD7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9033-3PH	P1	3 phase fault on the SUNNYSD7 (515136) to TERRYRD7 (511568) 345 kV line CKT 1, near SUNNYSD7. a. Apply fault at the SUNNYSD7 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.
FLT9034-3PH	P1	3 phase fault on the SUNNYSD7 (515136) to JOHNCO 7 (514809) 345 kV line CKT 1, near SUNNYSD7. a. Apply fault at the SUNNYSD7 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.
FLT9035-3PH	P1	3 phase fault on the JOHNCO 7 (514809) to PITTSB-7 (510907) 345 kV line CKT 1, near JOHNCO 7. a. Apply fault at the JOHNCO 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.
FLT9036-3PH	P1	3 phase fault on the JOHNCO 345 kV (514809) /138kV (514808)/ 13.8 kV (514810) XFMR CKT 1, near JOHNCO 7 (514809) 345 kV. a. Apply fault at the JOHNCO 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9037-3PH	P1	3 phase fault on the PITTSB-7 (510907) to SEMINOL7 (515045) 345 kV line CKT 1, near PITTSB-7. a. Apply fault at the PITTSB-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.
FLT9038-3PH	P1	3 phase fault on the PITTSB-7 (510907) to C-RIVER7 (515422) 345 kV line CKT 1, near PITTSB-7. a. Apply fault at the PITTSB-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.
FLT9039-3PH	P1	3 phase fault on the NWTCARK1 345 kV (508072) /138kV (508071)/ 13.8 kV (508100) XFMR CKT 1, near NWTXARK7 (508072) 345 kV. a. Apply fault at the NWTXARK7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.

Table 5-2 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9040-3PH	P1	3 phase fault on the NWTXARK7 (508072) to TURK 7 (507455) 345 kV line CKT 1, near NWTXARK7. a. Apply fault at the NWTXARK7 138kV 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.
FLT9041-3PH	P1	3 phase fault on the WELSH 7 (508359) to NWTXARK7 (508072) 345 kV line CKT 1, near WELSH 7. a. Apply fault at the WELSH 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.
FLT9042-3PH	P1	3 phase fault on the WELSH 7 (508359) to DIANA 7 (508832) 345 kV line CKT 1, near WELSH 7. a. Apply fault at the WELSH 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.
FLT9043-3PH	P1	3 phase fault on the WELSH 7 (508359) to WILKES 7 (508841) 345 kV line CKT 1, near WELSH 7. a. Apply fault at the WELSH 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.
FLT9044-3PH	P1	3 phase fault on the WELSH 3 345kV (508359) / 18kV (509406) XFMR CKT 1, near WELSH 7 (508359) 345kV. a. Apply fault at the WELSH 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted transformer. Trip the generator HUGO1 (509406).
FLT9045-3PH	P1	3 phase fault on the JOHNCO 7 (514809) to GEN-2017-149 (760830) 345 kV line CKT 1, near JOHNCO 7. a. Apply fault at the JOHNCO 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip the generator G17-154GEN1 (760854), G17-149GEN1 (760833). 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.
FLT9046-3PH	P1	3 phase fault on the JOHNCO 7 (514809) to DMNDSPG7 (516006) 345 kV line CKT 1, near JOHNCO 7. a. Apply fault at the JOHNCO 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip the generator DMNDSG11 (516000), DMNDSG21 (516001). 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.
FLT1001-SB	P4	**Stuck Breaker on VALIANT7 (510911) 345kV bus.** a. Apply single-phase fault at VALIANT7 (510911) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT3 138kV (510918) / 345 kV (510911)/ 13.8 kV (510939) XFMR CKT 1. d. Trip the VALIANT3 138kV (510918) / 345 kV (510911)/ 13.8 kV (510938) XFMR CKT 2.
FLT1002-SB	P4	**Stuck Breaker on VALIANT7 (510911) 345kV bus.** a. Apply single-phase fault at VALIANT7 (510911) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT3 138kV (510918) / 345 kV (510911)/ 13.8 kV (510939) XFMR CKT 1. d. Trip the VALIANT7 (510911) to PITTSB-7 (510907) 345 kV line CKT 1.
FLT1003-SB	P4	**Stuck Breaker on VALIANT7 (510911) 345kV bus.** a. Apply single-phase fault at VALIANT7 (510911) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT7 (510911) to LYDIA 7 (508298) 345 kV line CKT 1. d. Trip the VALIANT7 (510911) to PITTSB-7 (510907) 345 kV line CKT 1.
FLT1004-SB	P4	**Stuck Breaker on VALIANT7 (510911) 345kV bus.** a. Apply single-phase fault at VALIANT7 (510911) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT7 (510911) to LYDIA 7 (508298) 345 kV line CKT 1. d. Trip the VALIANT7 (510911) to HUGO 7 (521157) 345 kV line CKT 1.

Table 5-2 Continued

Fault ID	Planning Event	Fault Descriptions
FLT1005-SB	P4	**Stuck Breaker on VALIANT7 (510911) 345kV bus.** a. Apply single-phase fault at VALIANT7 (510911) on the 345kV bus. b. Wait 16 cycles and remove fault. d. Trip the VALIANT7 (510911) to HUGO 7 (521157) 345 kV line CKT 1. d. Trip the VALIANT7 (510911) to NWTXARK7 (508072) 345 kV line CKT 1.
FLT1006-SB	P4	**Stuck Breaker on VALIANT7 (510911) 345kV bus.** a. Apply single-phase fault at VALIANT7 (510911) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT3 138kV (510918) / 345 kV (510911)/ 13.8 kV (510938) XFMR CKT 2. d. Trip the VALIANT7 (510911) to NWTXARK7 (508072) 345 kV line CKT 1.
FLT1007-SB	P4	**Stuck Breaker on VALIANT4 (510918) 138kV bus.** a. Apply single-phase fault at VALIANT4 (510918) on the 138kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT4 (510918) to HUGO PP4 (520948) 138kV line CKT 1. d. Trip the VALIANT2 138kV (510918) / 69 kV (510910)/ 13.8 kV (510937) XFMR CKT 1.
FLT1008-SB	P4	**Stuck Breaker on VALIANT4 (510918) 138kV bus.** a. Apply single-phase fault at VALIANT4 (510918) on the 138kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT4 (510918) to HUGO PP4 (520948) 138kV line CKT 1. d. Trip the VALIANT3 138kV (510918) / 345 kV (510911)/ 13.8 kV (510939) XFMR CKT 1.
FLT1009-SB	P4	**Stuck Breaker on VALIANT4 (510918) 138kV bus.** a. Apply single-phase fault at VALIANT4 (510918) on the 138kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT4 (510918) to V-WEYCO4 (510866) 138kV line CKT 1. d. Trip the VALIANT3 138kV (510918) / 345 kV (510911)/ 13.8 kV (510939) XFMR CKT 1.
FLT1010-SB	P4	**Stuck Breaker on VALIANT4 (510918) 138kV bus.** a. Apply single-phase fault at VALIANT4 (510918) on the 138kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT4 (510918) to V-WEYCO4 (510866) 138kV line CKT 1. d. Trip the VALIANT4 (510918) to HUGO-4 (510901) 138kV line CKT 1.
FLT1011-SB	P4	**Stuck Breaker on VALIANT4 (510918) 138kV bus.** a. Apply single-phase fault at VALIANT4 (510918) on the 138kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT3 138kV (510918) / 345 kV (510911)/ 13.8 kV (510938) XFMR CKT 2. d. Trip the VALIANT4 (510918) to HUGO-4 (510901) 138kV line CKT 1. e. Trip the VALIANT4 (510918) to IDABEL-4 (510886) 138kV line CKT 1.
FLT1012-SB	P4	**Stuck Breaker on VALIANT4 (510918) 138kV bus.** a. Apply single-phase fault at VALIANT4 (510918) on the 138kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT3 138kV (510918) / 345 kV (510911)/ 13.8 kV (510938) XFMR CKT 2. d. Trip the VALIANT2 138kV (510918) / 69 kV (510910)/ 13.8 kV (510937) XFMR CKT 1. e. Trip the VALIANT4 (510918) to IDABEL-4 (510886) 138kV line CKT 1.
FLT1013-SB	P4	**Stuck Breaker on at HUGO 7 (521157) at 345kV bus.** a. Apply single-phase fault at HUGO 7 (521157) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the Bus HUGO 7 (521157).
FLT1014-SB	P4	**Stuck Breaker on at HUGO PP4 (520948) at 138kV bus.** a. Apply single-phase fault at HUGO PP4 (520948) on the 138kV bus. b. After 16 cycles, trip the following elements c. Trip the HUGO PP4 (520948) to SAWYER4 (520411) 138kV line CKT 1. d. Trip the HUGO PP4 (520948) to FROGVIL4 (520918) 138kV line CKT 1.
FLT1015-SB	P4	**Stuck Breaker on at HUGO PP4 (520948) at 138kV bus.** a. Apply single-phase fault at HUGO PP4 (520948) on the 138kV bus. b. After 16 cycles, trip the following elements c. Trip the YNd1 138kV (520948) / 23.4kV (520947) XFMR CKT 1 d. Trip the HUGO PP4 (520948) to VALLANT4 (521079) 138kV line CKT 1. Trip the generator HUGO1 (520947).

Table 5-2 Continued

Fault ID	Planning Event	Fault Descriptions
FLT1016-SB	P4	**Stuck Breaker on at HUGO PP4 (520948) at 138kV bus.** a. Apply single-phase fault at HUGO PP4 (520948) on the 138kV bus. b. After 16 cycles, trip the following elements c. Trip the HUGO PP4 (520948) to VALIANT4 (510918) 138kV line CKT 1. d. Trip the HUGO PP4 (520948) to GEN-2017-023 (588670) 138kV line CKT 1. Trip the generator G17-023-GEN1 (588673).

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 = 52.08 MW)

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
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
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

Table 5-3 continued

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	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
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

The results of the Scenario 1 dynamic stability showed several existing base case issues that were found in both the original DISIS-2017-002-1 model and the model with GEN-2023-SR15 included. These issues were not attributed to the GEN-2023-SR15 surplus request and detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2023-SR15 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

Table 5-4 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 = 35.28 MW, SGF = 52.08 MW)

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
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
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

Table 5-4 continued

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	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
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

The results of the Scenario 2 dynamic stability showed several existing base case issues that were found in both the original DISIS-2017-002-1 model and the model with GEN-2023-SR15 included. These issues were not attributed to the GEN-2023-SR15 surplus request and detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2023-SR15 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.

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-2023-SR15 may utilize the requested 50 MW of Surplus Interconnection Service being made available by GEN-2017-023.

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 85 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 Interconnection Service amount listed in the EGF's GIA. 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.