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Southwest Power Pool

Southwest Power Pool

Report On

GEN-2021-SR9
Surplus Service Impact Study

Revision R2

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anedenconsulting.com

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DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
12/14/2021	Aneden Consulting	Initial Report Issued.
2/15/2022	Aneden Consulting	Removed Battery Reference

Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Surplus Interconnection Service Impact Study (Study) for GEN-2021-SR9 to utilize the Surplus Interconnection Service provided by the Hawthorn Power Plant Unit 8 at its existing point of interconnection (POI), the Levee 161 kV substation in the Kansas City Power & Light (KCPL) control area.

GEN-2021-SR9, the proposed Surplus Generating Facility (SGF), will be located at the existing main collection substation used by Hawthorn Power Plant Unit 8, the Existing Generating Facility (EGF).

The EGF project has provided an Attestation of Existing Generator Interconnection Service Capacity (Attestation) showing a POI capacity of 96.75 MW and is making 10 MW of Surplus Interconnection Service available at its point of interconnection. Per the SPP Open Access Transmission Tariff (OATT), the amount of Surplus Interconnection Service available to be used by the SGF is limited by the amount of Interconnection Service granted to the EGF at the same POI. In this case, the EGF is limited by its nameplate maximum output at unity power factor per the Attestation. In addition, the Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades.

The proposed SGF configuration consists of 3 x Power Electronics FS3670K 3.8 MW solar inverters for a total capacity of 11.4 MW as shown in Table ES-1 below along with the EGF details. As the requested Surplus Interconnection Service is for 10 MW, the injection amount of the SGF must be limited to 10 MW at the POI. The combined generation from both the SGF and the EGF may not exceed 96.75 MW at the POI. GEN-2021-SR9 includes the use of a Power Plant Controller (PPC) to limit the power injection as required.

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

Table ES-1: EGF & SGF Configuration

Request	Capacity (MW)	Generator Configuration	Point of Interconnection
GEN-2021-SR9 (SGF)	10	3 x Power Electronics FS3670K 3.8 MW =11.4 MW PPC to limit generator output to 10 MW	Levee 161 kV (542976)
Hawthorn Power Plant Unit 8 (EGF)	96.75	Combustion Turbine	Levee 161 kV (542976)

Table ES-2: SGF Interconnection Configuration

Facility	GEN-2021-SR9
Point of Interconnection	LEVEE 161 kV (542976) at Hawthorn Power Plant
Configuration/Capacity	3 x Power Electronics FS3670K 3.8 MW = 11.4 MW (PPC to limit generator output to 10 MW) Total POI injection w/ Hawthorn Unit 8 limited to 96.75 MW
Generation Interconnection Line	N/A
Main Substation Transformer[1] (shared with EGF and unchanged)	X = 7.708%, R = 0.15%, Winding MVA = 60 MVA, Rating MVA = 100 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 3 (REGCAU1) X = 5.721%, R = 0.572%, Winding MVA = 11.4 MVA, Rating MVA = 11.4 MVA
Equivalent Collector Line[2]	R = 0.032022 pu X = 0.065202 pu B = 0.000841 pu

1) X/R based on Winding MVA, 2) all pu are on 100 MVA Base

SPP determined that power flow analysis was not required because the addition of the SGF does not increase the maximum active power output of 96.75 MW. In addition, with the improved EGF + SGF reactive capability at the maximum MW output, the combined facility can still maintain the original EGF reactive power injection at the POI.

The scope of this study included a charging current compensation analysis, a short circuit analysis, and a dynamic stability analysis.

Aneden performed the analyses using the study data provided by the SGF based on the DISIS-2017-001 study models:

1. 2019 Winter Peak (2019WP),
2. 2021 Light Load (2021LL),
3. 2021 Summer Peak (2021SP),
4. 2028 Summer Peak (2028SP)

All analyses were performed using the PTI PSS/E version 33 software and the results are summarized below.

The results of the charging current compensation analysis performed using the 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak models showed that the SGF project needed an approximately 0.08 MVAr shunt reactor at the project substation, to reduce the POI

MVAr to zero when the EGF project has a shunt compensating its charging effects. 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 charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

The results from the short circuit analysis compared the 2021SP and 2028SP models with the EGF online and SGF not connected to the SGF study case (EGF and SGF online) 2021SP and 2028SP models. The maximum contribution to three-phase fault currents in the immediate transmission systems due to the addition of the SGF was not greater than 0.06 kA. All three-phase fault current levels within 5 buses of the POI with the EGF and SGF generators online were below 53 kA for the 2021SP models and 2028SP models.

The dynamic stability analysis was performed using PTI PSS/E version 33.10 software and the four modified study models 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak with two dispatch scenarios. In the first scenario, the SGF was online at 10 MW while the EGF was disconnected. The second scenario included a combination of the SGF dispatched to maximum at 10 MW and the EGF picking up the remaining 86.75 MW for a total combination of 96.75 MW. Up to 85 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

The results of the dynamic stability analysis showed that there were numerous existing base case issues that were not attributed to the SGF project.

There were no damping or voltage recovery violations attributed to the GEN-2021-SR9 project 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-2021-SR9 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-2021-SR9 may utilize the requested 10 MW of Surplus Interconnection Service provided by the EGF. The combined generation from both the SGF and the EGF may not exceed 96.75 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 nameplate maximum output amount listed in the EGF's Attestation. The monitoring and control scheme will need to be reviewed by SPP and the TO and documented in Appendix C of the SGF Generation Interconnection Agreement (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-2021-SR9, 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 (OATT). The amount of Surplus Interconnection Service available to be used by 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. In this case, the EGF is limited by its nameplate maximum output at unity power factor per the Attestation. The Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades. 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 PTI PSS/E version 33 software. The results of each analysis are presented in the following sections.

1.1 Charging Current Compensation Analysis

SPP requires that a charging current compensation analysis be performed on the requested configuration as it is a non-synchronous resource. The charging current compensation 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 is 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 are 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 is performed on two scenarios, with the EGF dispatched and SGF offline, and the modified cases with both EGF and SGF dispatched.

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 is performed on two dispatch scenarios, the first where the SGF is dispatched to 100% with the EGF offline and disconnected, and the second where the EGF dispatch is reduced by the amount of Surplus Interconnection Service and the SGF is dispatched to 100%. Any mitigations, if required to address any stability issues, will be classified according to type of need, Interconnection Facility, Network Upgrade or Contingent Facility.

1.4 Power Flow

The power flow (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 may need to 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.

An SGF that includes a fuel type (synchronous/non-synchronous) different from the EGF may require a power flow analysis to study impacts resultant from changes in dispatch to all equal and lower queued requests. Any mitigations, if required to address any thermal or voltage violations, will be evaluated to determine if they are Interconnection Facility, Network Upgrade or Contingent Facility needs.

In addition, the reactive power capability of the combined (EGF + SGF) facility should be considered when determining the need for a power flow analysis.

1.5 Necessary Interconnection Facilities & Network Upgrades

The SPP OATT[1] 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.

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.

[1] SPP Open Access Transmission Tariff Section 3.34.1

2.0 Surplus Interconnection Service Request

The GEN-2021-SR9 Interconnection Customer has requested a Surplus Interconnection Service Impact Study (Study) for GEN-2021-SR9 to utilize the Surplus Interconnection Service provided by Hawthorn Power Plant Unit 8 at its existing point of interconnection (POI), the Levee 161 kV substation in the Kansas City Power & Light (KCPL) control area.

GEN-2021-SR9, the proposed SGF, will be located at the existing main collection substation used by Hawthorn Power Plant Unit 8, the EGF.

The EGF project has provided an Attestation of Existing Generator Interconnection Service Capacity (Attestation) with a POI capacity of 96.75 MW and is making 10 MW of Surplus Interconnection Service available at its point of interconnection. Per the SPP OATT the amount of Surplus Interconnection Service available to be used by the SGF is limited by the amount of Interconnection Service granted to the EGF at the same POI. In this case, the EGF is limited by its nameplate maximum output at unity power factor per the Attestation. In addition, the Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades.

At the time of the posting of this report, Hawthorn Power Plant Unit 8 (EGF) is an active existing generator at the same POI (Levee 161 kV) that pre-dates the SPP queue. Figure 2-1 shows the power flow model single line diagram for the EGF configuration.

The proposed SGF configuration consists of 3 x Power Electronics FS3670K 3.8 MW solar inverters for a total capacity of 11.4 MW as shown in Table 2-1 below along with the EGF details. As the requested Surplus Interconnection Service is for 10 MW, the injection amount of the SGF must be limited to 10 MW at the POI. The combined generation from both the SGF and the EGF may not exceed 96.75 MW at the POI. GEN-2021-SR9 includes the use of a Power Plant Controller (PPC) to limit the power injection as required. The proposed SGF configuration is captured in Figure 2-2 and Table 2-2 below.

Table 2-1: EGF & SGF Configuration

Request	Capacity (MW)	Generator Configuration	Point of Interconnection
GEN-2021-SR9 (SGF)	10	3 x Power Electronics FS3670K 3.8 MW =11.4 MW PPC to limit generator output to 10 MW	Levee 161 kV (542976)
Hawthorn Power Plant Unit 8 (EGF)	96.75	Combustion Turbine	Levee 161 kV (542976)

Figure 2-1: Hawthorn Power Plant Unit 8 Single Line Diagram (EGF Existing Configuration)

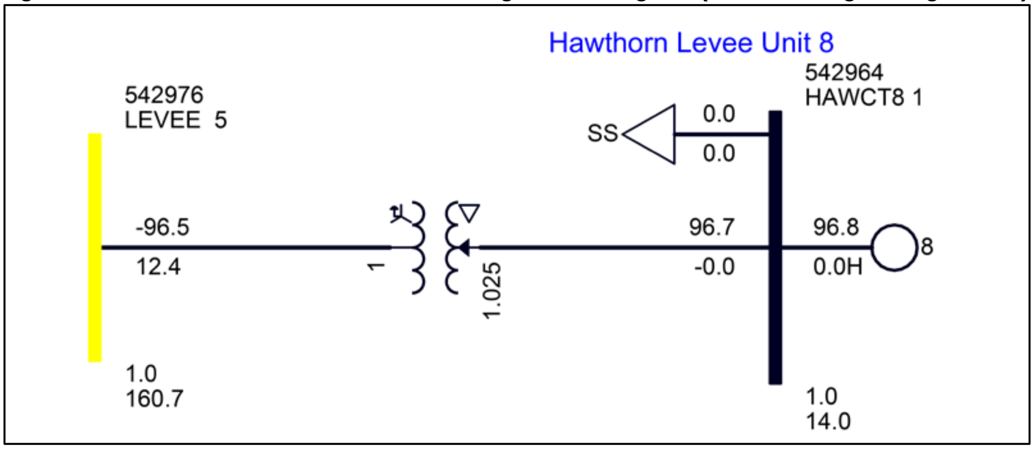


Figure 2-2: Hawthorn Power Plant Unit 8 & GEN-2021-SR9 Single Line Diagram (EGF & SGF Configuration)

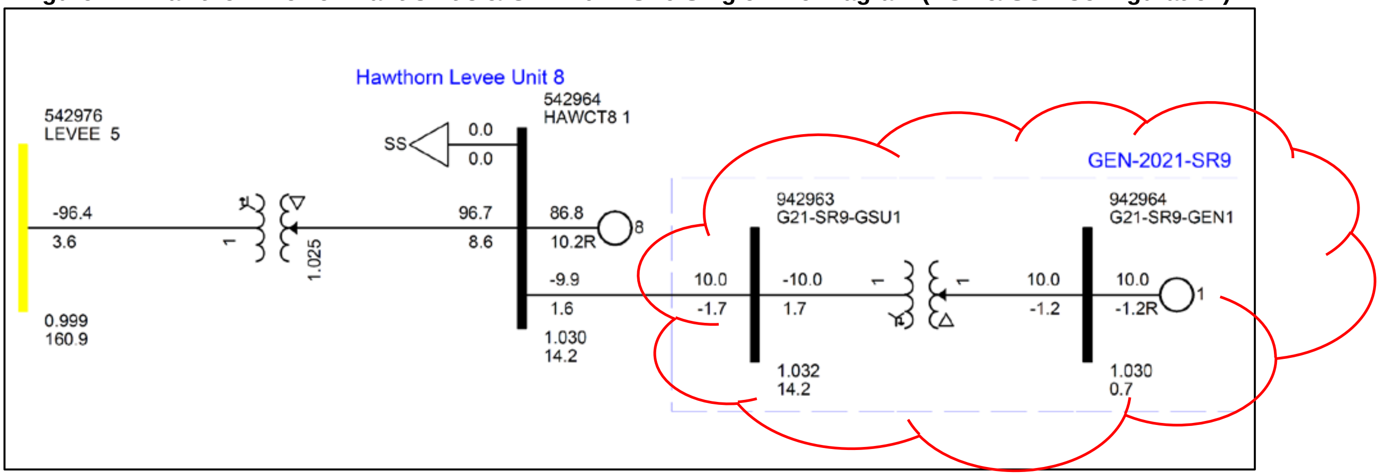


Table 2-2: SGF Interconnection Configuration

Facility	GEN-2021-SR9
Point of Interconnection	LEVEE 161 kV (542976) at Hawthorn Power Plant
Configuration/Capacity	3 x Power Electronics FS3670K 3.8 MW = 11.4 MW (PPC to limit generator output to 10 MW) Total POI injection w/ Hawthorn Unit 8 limited to 96.75 MW
Generation Interconnection Line	N/A
Main Substation Transformer[1] (shared with EGF and unchanged)	X = 7.708%, R = 0.15%, Winding MVA = 60 MVA, Rating MVA = 100 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 3 (REGCAU1) X = 5.721%, R = 0.572%, Winding MVA = 11.4 MVA, Rating MVA = 11.4 MVA
Equivalent Collector Line[2]	R = 0.032022 pu X = 0.065202 pu B = 0.000841 pu

1) X/R based on Winding MVA, 2) all pu are on 100 MVA Base

2.1 POI MW Injection Comparison

The real power injection at the POI was measured in PSS/E for the EGF configuration alone and for the EGF + SGF configuration with a total generator output of 96.75 MW. The difference in the POI injection was then compared for information.

There was an insignificant change (decrease of 0.07%) in the real power output at the POI between the EGF configuration and EGF + SGF configuration as shown in Table 2-3.

Table 2-3: POI Injection Comparison

Interconnection Request	EGF POI Injection (MW)	EGF + SGF POI Injection (MW)	POI Injection Difference %
GEN-2021-SR9	96.50	96.43	-0.07%

2.2 POI Injection Reactive Capability Comparison

The reactive power capability analysis was performed in PSS/E for the EGF configuration alone and for the EGF + SGF configuration to determine if the addition of the SGF would cause a deficiency in the reactive power capability and adversely impact the reliability conditions of the nearby system. As seen in Table 2-4, the EGF alone has a reactive capability of [-12.36 MVAr, -12.36 MVAr] ([Qmin, Qmax]) with the EGF is at its maximum generator active power output according to the EGF MOD-026 test report. On the other hand, the combined EGF + SGF configuration has a reactive capability of [-51.86 MVAr, 35.31 MVAr] at the POI. With the improved EGF + SGF reactive capability at the maximum MW output, the combined facility can still maintain the original EGF reactive power injection at the POI.

Table 2-4: POI Injection Reactive Capability Comparison

Scenario	EGF Output @ Generator (MW)	EGF Reactive Capability @ MW Output (MVAr)	SGF Output @ Generator (MW)	SGF Reactive Capability @ MW Output (MVAr)	POI Injection (MW)	POI Capability @ MW Output (MVAr)
EGF Alone	96.75	0.00	N/A	N/A	96.50	-12.36
EGF & SGF (Qmax)	86.75	44.00	10.00	5.48	96.40	35.31
EGF & SGF (Qmin)	86.75	-30.00	10.00	-5.48	96.25	-51.86

3.0 Charging Current Compensation Analysis

The charging current compensation analysis was performed for GEN-2021-SR9 to determine the capacitive charging effects required 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 required shunt reactor the SGF would need to compensate for the current charging attributed to its collection system, the charging current compensation 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 and reactive devices were switched offline while other collector system elements remained in-service as required. 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).

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 0.15 MVAr capacitor for the EGF to reduce the POI MVAr to approximately zero.

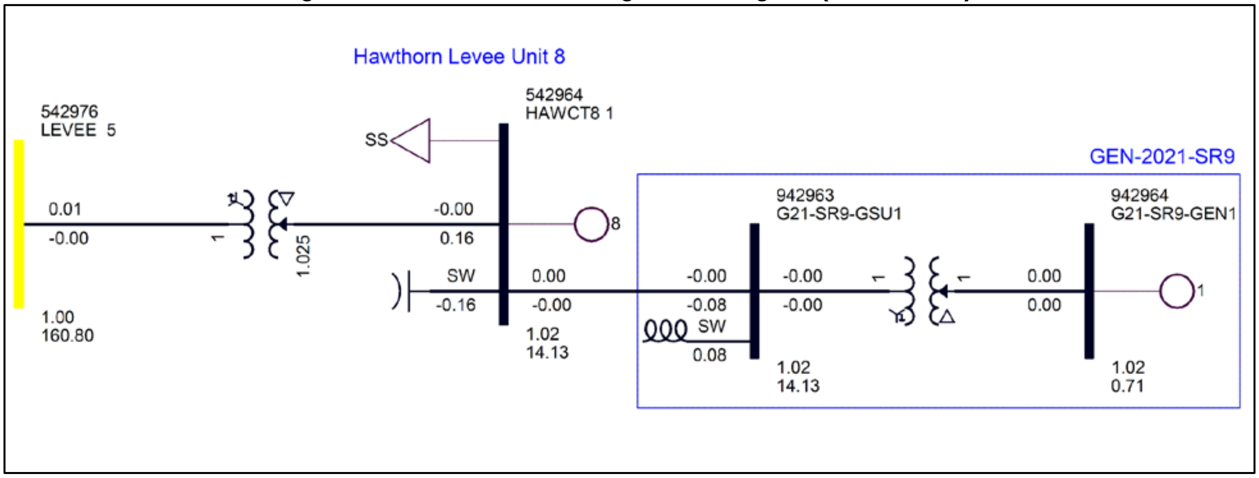
The results from the analysis showed that the SGF needed an approximately 0.08 MVAr shunt reactor at the SGF substation, to reduce the POI MVAr to zero with the pre-determined shunt for the EGF in-service. Figure 3-1 illustrates the shunt sizes needed to reduce the POI MVAr to approximately zero. The final shunt reactor requirements for the SGF are shown in Table 3-1.

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

Table 3-1: Shunt Reactor Size for Reduced Generation Study

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)			
			19WP	21LL	21SP	28SP
GEN-2021-SR9 (SGF)	542976	Levee 161 kV	0.08	0.08	0.08	0.08

Figure 3-1: GEN-2021-SR9 Single Line Diagram (Shunt Sizes)



4.0 Short Circuit Analysis

A short circuit study was performed using the 2021SP and 2028SP models 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 161 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 the EGF dispatch reduced by the amount of Surplus Interconnection Service and the SGF dispatched to 100% of its allowed capacity. In the second scenario the SGF was disconnected while the EGF stayed online at its full allowed capacity in order to determine the impact of the SGF.

4.2 Results

The results of the short circuit analysis compare the 2021SP and 2028SP models with the EGF online and SGF not connected (EGF = 96.75 MW, SGF disconnected) to the selected dispatch case (EGF = 86.75 MW, SGF = 10 MW) 2021SP and 2028SP models in Table 4-1 through Table 4-3. The POI bus fault current magnitudes are provided in Table 4-1 showing a maximum fault current of 46.56 kA with the EGF and SGF online. The addition of the SGF configuration increased the POI bus fault current by 0.06 kA.

The maximum fault current calculated within 5 buses of the POI was less than 53 kA for the 2021SP and 2028SP models respectively. The maximum contribution to three-phase fault currents due to the addition of the SGF was about 0.12% and 0.06 kA.

Table 4-1: POI Short Circuit Comparison Results

Case	EGF Only Current (kA)	SGF & EGF Current (kA)	Max kA Change	Max %Change
2021SP	46.49	46.55	0.06	0.12%
2028SP	46.52	46.56	0.05	0.10%

Table 4-2: 2021SP Short Circuit Comparison Results

Voltage (kV)	Max. Current (EGF & SGF) (kA)	Max kA Change	Max %Change
69	26.11	0.01	0.06%
161	52.21	0.06	0.12%
345	27.58	0.01	0.06%
Max	**52.21**	**0.06**	**0.12%**

Table 4-3: 2028SP Short Circuit Comparison Results

Voltage (kV)	Max. Current (EGF & SGF) (kA)	Max kA Change	Max %Change
69	26.5	0.01	0.05%
161	52.2	0.05	0.10%
345	27.5	0.01	0.05%
Max	**52.2**	**0.05**	**0.10%**

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 shown in Appendix C. The project details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix A. The simulation plots can be found in Appendix D.

5.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested 3 x Power Electronics FS3670K 3.8 MW = 11.4 MW (REGCAU1) SGF generating facility configuration included in the cases. The requested project configuration included the use of a PPC (REGCAU1). This stability analysis was performed using PTI's PSS/E version 33.10 software.

Two stability model scenarios were developed using the models from DISIS-2017-001. The first scenario (Scenario 1) was comprised of the SGF online and dispatched to maximum capacity (SGF = 10 MW) while the EGF generator was offline and disconnected. The second scenario (Scenario 2) was comprised of the SGF online and dispatched to maximum capacity (SGF = 10 MW) while the EGF generator dispatch was reduced by the amount of Surplus Interconnection Service (EGF = 86.75 MW). The study scenarios are shown in Table 5-1.

Table 5-1: Study Scenarios

Scenario	Hawthorn Power Plant Unit 8 EGF (MW)	GEN-2021-SR9 SGF (MW)	EGF + SGF (MW)
1	0	10	10
2	86.75	10	96.75

The following system adjustment was made to address existing base case issues that are not attributed to the Surplus Interconnection Request:

1. The instantaneous frequency and voltage trip relays were disabled for the Farmer City generator (635020)
2. Reduced the reactor from 300 MVAR to 200 MVAR at the GEN-2017-030 345 kV bus (588734)
3. GNET the equivalent DUMONT generator (243206) to avoid high frequency oscillations introduced by this generator.

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

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for the EGF and SGF and other equally and prior queued projects in Group 13[2]. 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

[2] Based on the DISIS-2017-001 Cluster Groups

asynchronous machines within this study area including 330 (AECI), 356 (AMMO), 536 (WERE), 540 (GMO), 541 (KCPL), 542 (KACY), 545 (INDN), 635 (MEC), 640 (NPPD), 645 (OPPD), 650 (LES), and 652 (WAPA) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

5.2 Fault Definitions

Aneden developed fault events as required in order to study the SGF. The new set of faults were simulated using the modified study models from both scenarios. The fault events included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers. The simulated faults are listed and described in Table 5-2 below. These contingencies were applied to the modified 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and the 2028 Summer Peak models.

Table 5-2: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT9001-3PH	P1	3 phase fault on the HAWTHN5 (543665) to BLUEVLY5 (543000) 161 kV line circuit 1, near HAWTHN5. a. Apply fault at the HAWTHN5 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.
FLT9002-3PH	P1	3 phase fault on the HAWTHORN20 161 kV (543665) /345 kV (542972) /13.8 kV (543644) transformer circuit 20, near HAWTHN5 161kV. a. Apply fault at the HAWTHN5 161 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9003-3PH	P1	3 phase fault on the HAWTHN5 (543665) to RANDLPH5 (543027) 161 kV line circuit 1, near HAWTHN5. a. Apply fault at the HAWTHN5 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.
FLT9004-3PH	P1	3 phase fault on the HAWTHN5 (543665) to CHOUTEU5 (543011) 161 kV line circuit 1, near HAWTHN5. a. Apply fault at the HAWTHN5 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.
FLT9005-3PH	P1	3 phase fault on the LEVEE 5 (542976) to HAWTHN5 (543665) 161 kV line circuit 1, near LEVEE 5. a. Apply fault at the LEVEE 5 161 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.
FLT9006-3PH	P1	3 phase fault on the HAWTHS5 (542973) to BRMGHAM5 (543020) 161 kV line circuit 1, near HAWTHS5. a. Apply fault at the HAWTHS5 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.
FLT9007-3PH	P1	3 phase fault on the HAWTHS5 (542973) to LEEDS 5 (542997) 161 kV line circuit 1, near HAWTHS5. a. Apply fault at the HAWTHS5 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.
FLT9008-3PH	P1	3 phase fault on the HAWTHS5 (542973) to SUB M-161 (548814) 161 kV line circuit 1, near HAWTHS5. a. Apply fault at the HAWTHS5 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.
FLT9009-3PH	P1	3 phase fault on the RANDLPH5 (543027) to AVONDAL5 (543015) 161 kV line circuit 1, near RANDLPH5. a. Apply fault at the RANDLPH5 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.
FLT9010-3PH	P1	3 phase fault on the NEASTS5 (542985) to CHOUTEU5 (543011) 161 kV line circuit 1, near NEASTS5. a. Apply fault at the NEASTS5 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.
FLT9011-3PH	P1	3 phase fault on the LEVEE 5 (542976) to NEASTN5 (543666) 161 kV line circuit 1, near LEVEE 5. a. Apply fault at the LEVEE 5 161 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
FLT9012-3PH	P1	3 phase fault on the BRMGHAM5 (543020) to LBRTYST5 (541248) 161 kV line circuit 1, near BRMGHAM5. a. Apply fault at the BRMGHAM5 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.
FLT9013-3PH	P1	3 phase fault on the BRMGHAM5 (543020) to LBRTYST5 (541248) 161 kV line circuit 1, near BRMGHAM5. a. Apply fault at the BRMGHAM5 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.
FLT9014-3PH	P1	3 phase fault on the LEEDS 5 (542997) to MIDTOWN5 (542996) 161 kV line circuit 1, near LEEDS 5. a. Apply fault at the LEEDS 5 161 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.
FLT9015-3PH	P1	3 phase fault on the LEEDS 5 (542997) to WINJT S5 (543010) 161 kV line circuit 1, near LEEDS 5. a. Apply fault at the LEEDS 5 161 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.
FLT9016-3PH	P1	3 phase fault on the LEEDS 5 (542997) to WINJT N5 (543009) 161 kV line circuit 1, near LEEDS 5. a. Apply fault at the LEEDS 5 161 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.
FLT9017-3PH	P1	3 phase fault on the LBRTYST5 (541248) to 5MOCITY (300098) 161 kV line circuit 1, near LBRTYST5. a. Apply fault at the LBRTYST5 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.
FLT9018-3PH	P1	3 phase fault on the SUB M-161 (548814) to BLUVLY-161 (548807) 161 kV line circuit 1, near SUB M-161. a. Apply fault at the SUB M-161 161 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.
FLT9019-3PH	P1	3 phase fault on the AVONDAL5 (543015) to GLADSTN5 (543016) 161 kV line circuit 1, near AVONDAL5. a. Apply fault at the AVONDAL5 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.
FLT9020-3PH	P1	3 phase fault on the AVONDAL5 (543015) to NKANCTY5 (543018) 161 kV line circuit 1, near AVONDAL5. a. Apply fault at the AVONDAL5 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.
FLT9021-3PH	P1	3 phase fault on the NEASTN5 (543666) to NKANCTY5 (543018) 161 kV line circuit 1, near NEASTN5. a. Apply fault at the NEASTN5 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
FLT9022-3PH	P1	3 phase fault on the NEASTN5 (543666) to GRAND 5 (542987) 161 kV line circuit 1, near NEASTN5. a. Apply fault at the NEASTN5 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.
FLT9023-3PH	P1	3 phase fault on the NEASTN5 (543666) to GRAND 5 (543021) 161 kV line circuit 1, near NEASTN5. a. Apply fault at the NEASTN5 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 the NEAST1314GSU 161 kV (543666) /13.8 kV (542971) /13.8 kV (542970) transformer circuit 1, near NEASTN5 161kV. a. Apply fault at the NEASTN5 161 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9025-3PH	P1	3 phase fault on the BLUEVLY5 (543000) to SUB N-161 (548820) 161 kV line circuit 1, near BLUEVLY5. a. Apply fault at the BLUEVLY5 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 the SUB N-161 (548820) to SUB R 161 (548831) 161 kV line circuit 1, near SUB N-161. a. Apply fault at the SUB N-161 161 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 the HAWTH 7 (542972) to NASHUA 7 (542980) 345 kV line circuit 1, near HAWTH 7. a. Apply fault at the HAWTH 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.
FLT9028-3PH	P1	3 phase fault on the HAWTH 7 (542972) to SIBLEY 7 (541201) 345 kV line circuit 1, near HAWTH 7. a. Apply fault at the HAWTH 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.
FLT9029-3PH	P1	3 phase fault on the NASHUA11 345 kV (542980) /161 kV (543028) /13.8 kV (543640) transformer circuit 11, near NASHUA 7 345 kV. a. Apply fault at the NASHUA 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9030-3PH	P1	3 phase fault on the NASHUA 7 (542980) to IATAN 7 (542982) 345 kV line circuit 1, near NASHUA 7. a. Apply fault at the NASHUA 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.
FLT9031-3PH	P1	3 phase fault on the NASHUA 7 (542980) to ST JOE 3 (541199) 345 kV line circuit 1, near NASHUA 7. a. Apply fault at the NASHUA 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.
FLT9032-3PH	P1	3 phase fault on the SIBLEY11 345 kV (541201) /161 kV (541202) /13.8 kV (541360) transformer circuit 11, near SIBLEY 7 345 kV. a. Apply fault at the SIBLEY 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.

Table 5-2 continued

Fault ID	Planning Event	Fault Descriptions
FLT9033-3PH	P1	3 phase fault on the SIBLEY 7 (541201) to PHILL 7 (541200) 345 kV line circuit 1, near SIBLEY 7. a. Apply fault at the SIBLEY 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.
FLT9034-3PH	P1	3 phase fault on the SIBLEY 7 (541201) to KETCHEM7 (541500) 345 kV line circuit 1, near SIBLEY 7. a. Apply fault at the SIBLEY 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.
FLT9035-3PH	P1	3 phase fault on the SIBLEY 7 (541201) to 7OVERTON (345408) 345 kV line circuit 1, near SIBLEY 7. a. Apply fault at the SIBLEY 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 ST JOE 3 (541199) to EASTOWN7 (541400) 345 kV line circuit 1, near ST JOE 3. a. Apply fault at the ST JOE 3 345 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.
FLT9037-3PH	P1	3 phase fault on the ST JOE 3 (541199) to 7FAIRPT (300039) 345 kV line circuit 1, near ST JOE 3. a. Apply fault at the ST JOE 3 345 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 ST JOE 3 (541199) to COOPER 3 (640139) 345 kV line circuit 1, near ST JOE 3. a. Apply fault at the ST JOE 3 345 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 ST.JOSEPH22 345 kV (541199) /161 kV (541253) /13.8 kV (541370) transformer circuit 22, near ST JOE 3 345 kV. a. Apply fault at the ST JOE 3 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9040-3PH	P1	3 phase fault on the IATAN 7 (542982) to G17-030-TAP (588736) 345 kV line circuit 1, near IATAN 7. a. Apply fault at the IATAN 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.
FLT9041-3PH	P1	3 phase fault on the IATAN 7 (542982) to STRANGR7 (532772) 345 kV line circuit 1, near IATAN 7. a. Apply fault at the IATAN 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 IATAN11 345 kV (542982) /161 kV (541350) /13.8 kV (541150) transformer circuit 11, near IATAN 7 345 kV. a. Apply fault at the IATAN 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9043-3PH	P1	3 phase fault on the IATAN11 345 kV (542982) /24 kV (542957) transformer circuit 1, near IATAN 7 345 kV. a. Apply fault at the IATAN 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer. **Trip the generator IAT G1 1 (542957).**

Table 5-2 continued

Fault ID	Planning Event	Fault Descriptions
FLT9044-3PH	P1	3 phase fault on the P HILL11 345 kV (541200) /161 kV (541225) /13.8 kV (541361) transformer circuit 11, near PHILL 7 345 kV. a. Apply fault at the PHILL 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9045-3PH	P1	3 phase fault on the PHILL 7 (541200) to PECULR 7 (541198) 345 kV line circuit 1, near PHILL 7. a. Apply fault at the PHILL 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.
FLT9046-3PH	P1	3 phase fault on the KETCHEM7 (541500) to OSBORN7 (541501) 345 kV line circuit 1, near KETCHEM7. a. Apply fault at the KETCHEM7 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.
FLT9047-3PH	P1	3 phase fault on the KETCHEM7 (541500) to MULLNCR7 (541197) 345 kV line circuit 1, near KETCHEM7. a. Apply fault at the KETCHEM7 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.
FLT9048-3PH	P1	3 phase fault on the KETCHEM7 (541500) to GEN-2016-088 (587730) 345 kV line circuit 1, near KETCHEM7. a. Apply fault at the KETCHEM7 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.
FLT9049-3PH	P1	3 phase fault on the 7OVERTON 345 kV (345408) /161 kV (345409) transformer circuit 1, near 7OVERTON 345 kV. a. Apply fault at the 7OVERTON 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9050-3PH	P1	3 phase fault on the 7OVERTON (345408) to 7MCCREDIE (345088) 345 kV line circuit 1, near 7OVERTON. a. Apply fault at the 7OVERTON 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.
FLT9051-3PH	P1	3 phase fault on the HAWTHN5 161kV (543665)/ 22kV (542951) transformer circuit 1, near HAWTHN5 (543665). a. Apply fault at the HAWTHN5 161 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. **Trip the generator HAW G5 1 (542951).**
FLT9010-PO1	P6	**PRIOR OUTAGE of LEVEE 5 (542976) to HAWTHN5 (543665) 161 kV line circuit 1;** 3 phase fault on the NEASTS5 (542985) to CHOUTEU5 (543011) 161 kV line circuit 1, near NEASTS5. a. Apply fault at the NEASTS5 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.
FLT9021-PO1	P6	**PRIOR OUTAGE of LEVEE 5 (542976) to HAWTHN5 (543665) 161 kV line circuit 1;** 3 phase fault on the NEASTN5 (543666) to NKANCTY5 (543018) 161 kV line circuit 1, near NEASTN5. a. Apply fault at the NEASTN5 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
FLT9022-PO1	P6	**PRIOR OUTAGE of LEVEE 5 (542976) to HAWTHN5 (543665) 161 kV line circuit 1;** 3 phase fault on the NEASTN5 (543666) to GRAND 5 (542987) 161 kV line circuit 1, near NEASTN5. a. Apply fault at the NEASTN5 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.
FLT9023-PO1	P6	**PRIOR OUTAGE of LEVEE 5 (542976) to HAWTHN5 (543665) 161 kV line circuit 1;** 3 phase fault on the NEASTN5 (543666) to GRAND 5 (543021) 161 kV line circuit 1, near NEASTN5. a. Apply fault at the NEASTN5 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-PO1	P6	**PRIOR OUTAGE of LEVEE 5 (542976) to HAWTHN5 (543665) 161 kV line circuit 1;** 3 phase fault on the NEAST1314GSU 161 kV (543666) /13.8 kV (542971) /13.8 kV (542970) transformer circuit 1, near NEASTN5 161kV. a. Apply fault at the NEASTN5 161 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9001-PO2	P6	**PRIOR OUTAGE of the LEVEE 5 (542976) to NEASTN5 (543666) 161 kV line circuit 1;** 3 phase fault on the HAWTHN5 (543665) to BLUEVLY5 (543000) 161 kV line circuit 1, near HAWTHN5. a. Apply fault at the HAWTHN5 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.
FLT9002-PO2	P6	**PRIOR OUTAGE of the LEVEE 5 (542976) to NEASTN5 (543666) 161 kV line circuit 1;** 3 phase fault on the HAWTHORN20 161 kV (543665) /345 kV (542972) /13.8 kV (543644) transformer circuit 20, near HAWTHN5 161kV. a. Apply fault at the HAWTHN5 161 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9003-PO2	P6	**PRIOR OUTAGE of the LEVEE 5 (542976) to NEASTN5 (543666) 161 kV line circuit 1;** 3 phase fault on the HAWTHN5 (543665) to RANDLPH5 (543027) 161 kV line circuit 1, near HAWTHN5. a. Apply fault at the HAWTHN5 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.
FLT9004-PO2	P6	**PRIOR OUTAGE of the LEVEE 5 (542976) to NEASTN5 (543666) 161 kV line circuit 1;** 3 phase fault on the HAWTHN5 (543665) to CHOUTEU5 (543011) 161 kV line circuit 1, near HAWTHN5. a. Apply fault at the HAWTHN5 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.
FLT9006-PO2	P6	**PRIOR OUTAGE of the LEVEE 5 (542976) to NEASTN5 (543666) 161 kV line circuit 1;** 3 phase fault on the HAWTHS5 (542973) to BRMGHAM5 (543020) 161 kV line circuit 1, near HAWTHS5. a. Apply fault at the HAWTHS5 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.
FLT9007-PO2	P6	**PRIOR OUTAGE of the LEVEE 5 (542976) to NEASTN5 (543666) 161 kV line circuit 1;** 3 phase fault on the HAWTHS5 (542973) to LEEDS 5 (542997) 161 kV line circuit 1, near HAWTHS5. a. Apply fault at the HAWTHS5 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
FLT9008-PO2	P6	**PRIOR OUTAGE of the LEVEE 5 (542976) to NEASTN5 (543666) 161 kV line circuit 1;** 3 phase fault on the HAWTHS5 (542973) to SUB M-161 (548814) 161 kV line circuit 1, near HAWTHS5. a. Apply fault at the HAWTHS5 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-PO2	P6	**PRIOR OUTAGE of the LEVEE 5 (542976) to NEASTN5 (543666) 161 kV line circuit 1;** 3 phase fault on the HAWTHN5 161kV (543665)/ 22kV (542951) transformer circuit 1, near HAWTHN5 (543665). a. Apply fault at the HAWTHN5 161 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. **Trip the generator HAW G5 1 (542951).**
FLT1001-SB	P4	**Stuck Breaker on at LEEDS 5 (542997) at 161kV bus** a. Apply single-phase fault at LEEDS 5 (542997) on the 161kV bus. b. After 16 cycles, trip the following elements c. Trip the LEEDS 5 (542997) to MIDTOWN5 (542996) 161 kV line circuit 1. d. Trip the LEEDS 5 (542997) to WINJT N5 (543009) 161 kV line circuit 1.
FLT1002-SB	P4	**Stuck Breaker on at LEEDS 5 (542997) at 161kV bus** a. Apply single-phase fault at LEEDS 5 (542997) on the 161kV bus. b. After 16 cycles, trip the following elements c. Trip the LEEDS 5 (542997) to MIDTOWN5 (542996) 161 kV line circuit 1. d. Trip the LEEDS 5 (542997) to HAWTHS5 (542973) 161 kV line circuit 2.
FLT1003-SB	P4	**Stuck Breaker on at LEEDS 5 (542997) at 161kV bus** a. Apply single-phase fault at LEEDS 5 (542997) on the 161kV bus. b. After 16 cycles, trip the following elements c. Trip the LEEDS 5 (542997) to WINJT S5 (543010) 161 kV line circuit 1. d. Trip the LEEDS 5 (542997) to HAWTHS5 (542973) 161 kV line circuit 2.
FLT1004-SB	P4	**Stuck Breaker on at LEEDS 5 (542997) at 161kV bus** a. Apply single-phase fault at LEEDS 5 (542997) on the 161kV bus. b. After 16 cycles, trip the following elements c. Trip the LEEDS 5 (542997) to WINJT S5 (543010) 161 kV line circuit 1. d. Trip the LEEDS 5 (542997) to HAWTHS5 (542973) 161 kV line circuit 1.
FLT1005-SB	P4	**Stuck Breaker on at LEEDS 5 (542997) at 161kV bus** a. Apply single-phase fault at LEEDS 5 (542997) on the 161kV bus. b. After 16 cycles, trip the following elements c. Trip the LEEDS 5 (542997) to WINJT N5 (543009) 161 kV line circuit 1. d. Trip the LEEDS 5 (542997) to HAWTHS5 (542973) 161 kV line circuit 1.
FLT1006-SB	P4	**Stuck Breaker on at BRMGHAM5 (543020) at 161 kV bus** a. Apply single-phase fault at BRMGHAM5 (543020) at 161 kV bus. b. After 16 cycles, trip the following elements c. Trip the Bus BRMGHAM5 (543020).
FLT1007-SB	P4	**Stuck Breaker on at LEVEE 5 (542976) at 161 kV bus** a. Apply single-phase fault at LEVEE 5 (542976) at 161 kV bus. b. After 16 cycles, trip the following elements c. Trip the Bus LEVEE 5 (542976). Trip the generator G21-SR9-GEN1 (942964).
FLT1008-SB	P4	**Stuck Breaker on at HAWTHN5 (543665) at 161kV bus** a. Apply single-phase fault at HAWTHN5 (543665) on the 161kV bus. b. After 16 cycles, trip the following elements c. Trip the HAWTHN5 (543665) to LEVEE 5 (542976) 161 kV line circuit 1. d. Trip the HAWTHORN20 161 kV (543665) /345 kV (542972) /13.8 kV (543645) transformer circuit 22.
FLT1009-SB	P4	**Stuck Breaker on at HAWTHN5 (543665) at 161kV bus** a. Apply single-phase fault at HAWTHN5 (543665) on the 161kV bus. b. After 16 cycles, trip the following elements c. Trip the HAWTHN5 (543665) to LEVEE 5 (542976) 161 kV line circuit 1. d. Trip the HAWTHORN20 161 kV (543665) /345 kV (542972) /13.8 kV (543644) transformer circuit 20.
FLT1010-SB	P4	**Stuck Breaker on at HAWTHN5 (543665) at 161kV bus** a. Apply single-phase fault at HAWTHN5 (543665) on the 161kV bus. b. After 16 cycles, trip the following elements c. Trip the HAWTHN5 (543665) to RANDLPH5 (543027) 161 kV line circuit 1. d. Trip the HAWTHORN20 161 kV (543665) /345 kV (542972) /13.8 kV (543644) transformer circuit 20.

Table 5-2 continued

Fault ID	Planning Event	Fault Descriptions
FLT1011-SB	P4	**Stuck Breaker on at HAWTHN5 (543665) at 161kV bus** a. Apply single-phase fault at HAWTHN5 (543665) on the 161kV bus. b. After 16 cycles, trip the following elements c. Trip the HAWTHN5 (543665) to BLUEVLY5 (543000) 161 kV line circuit 1. d. Trip the HAWTHORN20 161 kV (543665) /345 kV (542972) /13.8 kV (543645) transformer circuit 22.
FLT1012-SB	P4	**Stuck Breaker on at HAWTHN5 (543665) at 161kV bus** a. Apply single-phase fault at HAWTHN5 (543665) on the 161kV bus. b. After 16 cycles, trip the following elements c. Trip the HAWTHN5 (543665) to RANDLPH5 (543027) 161 kV line circuit 1. d. Trip the HAWTHN5 (543665) to CHOUTEU5 (543011) 161 kV line circuit 1.
FLT1013-SB	P4	**Stuck Breaker on at HAWTHN5 (543665) at 161kV bus** a. Apply single-phase fault at HAWTHN5 (543665) on the 161kV bus. b. After 16 cycles, trip the following elements c. Trip the HAWTHN5 (543665) to CHOUTEU5 (543011) 161 kV line circuit 1. d. Trip the HAWTHN5 161kV (543665)/ 22kV (542951) transformer circuit 1. **Trip the generator HAW G5 1 (542951).**
FLT1014-SB	P4	**Stuck Breaker on at HAWTHN5 (543665) at 161kV bus** a. Apply single-phase fault at HAWTHN5 (543665) on the 161kV bus. b. After 16 cycles, trip the following elements c. Trip the HAWTHN5 (543665) to BLUEVLY5 (543000) 161 kV line circuit 2. d. Trip the HAWTHN5 161kV (543665)/ 22kV (542951) transformer circuit 1. **Trip the generator HAW G5 1 (542951).**
FLT1015-SB	P4	**Stuck Breaker on at HAWTHS5 (542973) at 161kV bus** a. Apply single-phase fault at HAWTHS5 (542973) on the 161kV bus. b. After 16 cycles, trip the following elements c. Trip the HAWTHS5 (542973) to LEEDS 5 (542997) 161 kV line circuit 1. d. Trip the HAWTHS5 (542973) to SUB M-161 (548814) 161 kV line circuit 1.
FLT1016-SB	P4	**Stuck Breaker on at HAWTHS5 (542973) at 161kV bus** a. Apply single-phase fault at HAWTHS5 (542973) on the 161kV bus. b. After 16 cycles, trip the following elements c. Trip the HAWTHS5 (542973) to LEEDS 5 (542997) 161 kV line circuit 1. d. Trip the HAWTHN5 161kV (542973)/ 16kV (542961) transformer circuit 1. **Trip the generator HAWCT6 1 (542961).**
FLT1017-SB	P4	**Stuck Breaker on at HAWTHS5 (542973) at 161kV bus** a. Apply single-phase fault at HAWTHS5 (542973) on the 161kV bus. b. After 16 cycles, trip the following elements c. Trip the HAWTHS5 (542973) to BRMGHAM5 (543020) 161 kV line circuit 1. d. Trip the HAWTHN5 161kV (542973)/ 16kV (542961) transformer circuit 1. **Trip the generator HAWCT6 1 (542961).**
FLT1018-SB	P4	**Stuck Breaker on at HAWTHS5 (542973) at 161kV bus** a. Apply single-phase fault at HAWTHS5 (542973) on the 161kV bus. b. After 16 cycles, trip the following elements c. Trip the HAWTHORN11 161kV (542973)/ 69kV (543663) transformer circuit 11. d. Trip the HAWTHS5 (542973) to SUB M-161 (548814) 161 kV line circuit 1.
FLT1019-SB	P4	**Stuck Breaker on at HAWTHS5 (542973) at 161kV bus** a. Apply single-phase fault at HAWTHS5 (542973) on the 161kV bus. b. After 16 cycles, trip the following elements c. Trip the HAWTHOR T2 161kV (542973)/ 13.2kV (543003) transformer circuit 1. d. Trip the HAWTHORN11 161kV (542973)/ 69kV (543663) transformer circuit 11.
FLT1020-SB	P4	**Stuck Breaker on at HAWTHS5 (542973) at 161kV bus** a. Apply single-phase fault at HAWTHS5 (542973) on the 161kV bus. b. After 16 cycles, trip the following elements c. Trip the HAWTHOR T2 161kV (542973)/ 13.2kV (543003) transformer circuit 1. d. Trip the HAWTHS5 (542973) to LEEDS 5 (542997) 161 kV line circuit 2.
FLT1021-SB	P4	**Stuck Breaker on at HAWTHS5 (542973) at 161kV bus** a. Apply single-phase fault at HAWTHS5 (542973) on the 161kV bus. b. After 16 cycles, trip the following elements c. Trip the HAWTH9 GSU 161kV (542973)/ 16kV (542967) transformer circuit 1. d. Trip the HAWTHS5 (542973) to LEEDS 5 (542997) 161 kV line circuit 2. **Trip the generator HAW G9 1 (542967).**

5.3 Scenario 1 Results

Table 5-3 shows the results of the fault events simulated for each of the four modified cases in Scenario 1. The associated stability plots are provided in Appendix D.

Table 5-3: Scenario 1 (EGF = 0 MW, SGF = 10 MW)

Fault ID	19WP			21LL			21SP			26SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9027-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9028-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 5-3 continued

Fault ID	19WP			21LL			21SP			26SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9029-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9030-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9031-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9032-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9033-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9034-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9035-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9036-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9037-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9038-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9039-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9040-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9041-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9042-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9043-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9044-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9045-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9046-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9047-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9048-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9049-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9050-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9051-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 5-3 continued

Fault ID	19WP			21LL			21SP			26SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1011-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1012-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1013-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1014-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1015-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1016-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1017-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1018-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1019-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1020-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1021-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9051-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

There were no damping or voltage recovery violations attributed to the GEN-2021-SR9 project 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 results of the fault events simulated for each of the four modified cases in Scenario 2. The associated stability plots are provided in Appendix D.

Table 5-4: Scenario 2 (EGF = 86.75 MW, SGF = 10 MW)

Fault ID	19WP			21LL			21SP			26SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9027-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9028-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 5-4 continued

Fault ID	19WP			21LL			21SP			26SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9029-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9030-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9031-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9032-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9033-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9034-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9035-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9036-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9037-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9038-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9039-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9040-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9041-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9042-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9043-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9044-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9045-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9046-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9047-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9048-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9049-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9050-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9051-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 5-4 continued

Fault ID	19WP			21LL			21SP			26SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1011-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1012-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1013-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1014-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1015-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1016-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1017-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1018-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1019-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1020-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1021-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9051-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

There were no damping or voltage recovery violations attributed to the GEN-2021-SR9 project 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 of 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.

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.

7.0 Surplus Interconnection Service Determination and Requirements

In accordance with Attachment V of SPP's Open Access Transmission 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.

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 power flow results are not negatively impacted.

SPP has determined that GEN-2021-SR9 may utilize the requested 10 MW of Surplus Interconnection Service provided by Hawthorn Power Plant Unit 8.

7.2 Surplus Service Requirements

The amount of Surplus Interconnection Service available to be used is limited by the EGF nameplate maximum output at unity power factor. The combined generation from both the SGF and the EGF may not exceed 96.75 MW at the POI, which is the EGF nameplate maximum output at unity power factor.

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 nameplate maximum capacity stated in the EGF's Attestation. The monitoring and control scheme will need to be reviewed by SPP and the TO and documented in Appendix C of the SGF Generation Interconnection Agreement (GIA).

8.0 Conclusions

The GEN-2021-SR9 Interconnection Customer has requested a Surplus Interconnection Service Impact Study (Study) for GEN-2021-SR9 (SGF) to utilize the Surplus Interconnection Service provided by Hawthorn Power Plant Unit 8 (EGF) at its existing the point of interconnection (POI), the Levee 161 kV substation.

The scope of this study included a charging current compensation analysis, short circuit analysis, and dynamic stability analysis. SPP determined that power flow analysis was not required because the addition of the SGF does not increase the maximum active power output of 96.75 MW. In addition, with the improved EGF + SGF reactive capability at the maximum MW output, the combined facility can still maintain the original EGF reactive power injection at the POI.

All analyses were performed using the PTI PSS/E version 33 software and the results are summarized below.

The results of the charging current compensation analysis performed using the 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak models showed that the SGF project needed an approximately 0.08 MVAr shunt reactor at the project substation, to reduce the POI MVAr to zero when the EGF project has a shunt compensating its charging effects. 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 charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

The results from the short circuit analysis compared the 2021SP and 2028SP models with the EGF online and SGF not connected to the SGF study case (EGF and SGF online) 2021SP and 2028SP models. The maximum contribution to three-phase fault currents in the immediate transmission systems due to the addition of the SGF was not greater than 0.06 kA. All three-phase fault current levels within 5 buses of the POI with the EGF and SGF generators online were below 53 kA for the 2021SP models and 2028SP models.

The dynamic stability analysis was performed using PTI PSS/E version 33.10 software and the four modified study models 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak with two dispatch scenarios. In the first scenario, the SGF was online at 10 MW while the EGF was offline and disconnected. The second scenario included a combination of the SGF dispatched to maximum at 10 MW and the EGF picking up the remaining 86.75 MW for a total combination of 96.75 MW. Up to 85 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

The results of the dynamic stability analysis showed that there were numerous existing base case issues that were not attributed to the SGF project.

There were no damping or voltage recovery violations attributed to the GEN-2021-SR9 project 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-2021-SR9 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-2021-SR9 may utilize the requested 10 MW of Surplus Interconnection Service provided by the EGF. The combined generation from both the SGF and the EGF may not exceed 96.75 MW at the POI which is the EGF nameplate maximum output at unity power factor.

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 nameplate maximum output listed in the EGF's Attestation. The monitoring and control scheme will need to be reviewed by SPP and 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.