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Southwest Power Pool

Report On

GEN-2020-SR3
Surplus Service Impact Study

Revision R1

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anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
06/30/2021	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-2020-SR3 to utilize the Surplus Interconnection Service provided by GEN-2016-063 at its existing point of interconnection (POI), the G16-063-TAP bus on the Sunnyside to Hugo 345 kV line in the Oklahoma Gas and Electric (OKGE) control area.

GEN-2020-SR3, the proposed Surplus Generating Facility (SGF), will be located at the existing main collection substation used by GEN-2016-063, the Existing Generating Facility (EGF).

The EGF project has an effective Generator Interconnection Agreement (GIA) with a POI capacity of 200 MW and is making 200 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 addition, the Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades.

The GEN-2020-SR3 proposed configuration consists of 64 x Power Electronics FP3510M2 3.267 MW batteries for total capacity of 209.09 MW as shown in Table ES-1 below along with the EGF details. As the requested Surplus Interconnection Service is for 200 MW, the injection amount of GEN-2020-SR3 must be limited to 200 MW at the POI. The combined generation from both the SGF and the EGF may not exceed 200 MW at the POI, which is the total Interconnection Service amount currently granted to the EGF. GEN-2020-SR3 includes the use of a Power Plant Controller (PPC) to limit the power injection as required.

The GEN-2020-SR3 configuration is captured in Table ES-2 below.

Table ES-1: EGF & SGF Configuration

Request	Capacity (MW)	Surplus Generator Configuration	Point of Interconnection
GEN-2020-SR3 (SGF)	200	64 x Power Electronics FP3510M2 3.267 MW = 209.09 PPC to limit POI to 200MW	Tap on Sunnyside (515136) to Hugo (521157) 345 kV (G16-063-TAP 560088)
GEN-2016-063 (EGF)	200	100 x Vestas V110 2.0MW = 200 MW	Tap on Sunnyside (515136) to Hugo (521157) 345 kV (G16-063-TAP 560088)

Table ES-2: GEN-2020-SR3 Interconnection Configuration

Facility	GEN-2020-SR3	
Point of Interconnection	Tap on Sunnyside (515136) to Hugo (521157) 345 kV (G16-063-TAP 560088)	
Configuration/Capacity	64 x Power Electronics FP3510M2 3.267 MW = 209.09 MW PPC to limit POI to 200MW	
Existing Generation Interconnection Line (shared with EGF and unchanged)	Length = 0.5 miles R = 0.000082 pu X = 0.000340 pu B = 0.003100 pu	
Existing Main Substation Transformers[1] (shared with EGF and unchanged)	Transformer T1: X = 8.999%, R = 0.134%, Winding MVA = 75 MVA Rating MVA = 125 MVA	Transformer T2: X = 8.998%, R = 0.134%, Winding MVA = 75 MVA Rating MVA = 125 MVA
Equivalent GSU Transformer[1]	X = 8.465%, R = 0.77%, Winding MVA = 116.16 MVA Rating MVA[2] = 116.2 MVA	X = 8.465%, R = 0.77%, Winding MVA = 116.16 MVA Rating MVA[2] = 116.2 MVA
Equivalent Collector Line[3]	R = 0.002215 pu X = 0.002827 pu B = 0.017128 pu	R = 0.002215 pu X = 0.002827 pu B = 0.017128 pu

1) X/R based on Winding MVA, 2) Rating rounded up in PSS/E, 3) all pu are on 100 MVA Base

Since the EGF and SGF are both non-synchronous fuel types, SPP determined that power flow analysis is not required because the EGF was studied previously under the required reliability conditions.

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-2016-002 Group 14 study models:

1. 2017 Winter Peak (2017WP),
2. 2018 Summer Peak (2018SP), and
3. 2026 Summer Peak (2026SP).

All analyses were performed using the PTI PSS/E version 33.7 software and the results are summarized below.

The results of the charging current compensation analysis performed using the 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak models showed that the GEN-2020-SR3 SGF project needed an approximately 3.75 MVAr shunt reactor at the project substation, to reduce the POI MVAr to zero with the EGF offline and disconnected. This is a decrease from the 10.1 MVAr found for the EGF alone in the DISIS study[1]. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind or no-wind 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 existing DISIS case (EGF online, SGF not included) 2018SP and 2026SP models to the SGF study case (EGF and SGF online) 2018SP and 2026SP models. The maximum contribution to three-phase fault currents in the immediate systems due to the addition of the SGF was not greater than 0.151 kA. All three-phase fault current levels within 5 buses of the POI with the EGF and SGF generators online were below 40 kA for the 2018SP models and 2026SP models.

The dynamic stability analysis was performed using the three DISIS-2016-002 models 2017 Winter Peak, 2018 Summer Peak, 2026 Summer Peak with two dispatch scenarios. In the first scenario, the SGF was online at 200 MW while the EGF was offline with the collection system disconnected. Aneden and SPP selected the second scenario based on a combination of SGF and EGF dispatch scenarios with the project dispatches varied by 10 MW increments of the total capacity of 200 MW. The resulting selected worst-case scenario include a combination of the SGF dispatched to 10 MW and the EGF to 190 MW. Up to 43 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 no damping or voltage recovery violations 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-2020-SR3 did not negatively impact the reliability of the Transmission System. There were no additional Interconnection Facilities or Network Upgrades identified by the analyses and the Transmission Owner did not identify any Interconnection Facilities required for the Surplus Interconnection Request at the time of posting. A Surplus Interconnection Service Facility Study will not be required per the Transmission Owner.

SPP has determined that GEN-2020-SR3 may utilize the requested 200 MW of Surplus Interconnection Service provided by GEN-2016-063. The combined generation from both the SGF and the EGF may not exceed 200 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

[1] Definitive Interconnection System Impact Study Report DISIS-2016-001-1, December 22, 2017

power injected at the POI does not exceed the Interconnection Service amount listed in the EGF's GIA. The monitoring and control scheme will need to be reviewed by SPP and the TO and documented in Appendix C of the 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-2020-SR3, 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 Surplus Generating Facility (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. 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 33.7 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, the existing cases with EGF as 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 EGF is offline and the SGF is dispatched to 100%, and the second which is determined to be the worst-case scenario based on a dispatch test described in Section 5.3. 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 shall be performed to the required level necessary to demonstrate reliable operation of the Surplus Interconnection Service. If the original system impact study is not available for the Interconnection Service, both off-peak and peak analysis may need to be performed for the EGF associated with the request.

An SGF that includes a fuel type (synchronous/non-synchronous) different from the EGF will 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.

Since the EGF and SGF are both non-synchronous fuel types, SPP determined that power flow analysis is not required because the EGF was studied previously under the required reliability conditions.

1.5 Necessary Interconnection Facilities & Network Upgrades

The SPP OATT[2] 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.

[2] SPP Open Access Transmission Tariff Section 3.34.1

2.0 Surplus Interconnection Service Request

The GEN-2020-SR3 Interconnection Customer has requested a Surplus Interconnection Service Impact Study (Study) for GEN-2020-SR3 to utilize the Surplus Interconnection Service provided by GEN-2016-063 at its existing point of interconnection (POI), the G16-063-TAP bus on the Sunnyside to Hugo 345 kV line in the Oklahoma Gas and Electric (OKGE) control area.

GEN-2020-SR3, the proposed SGF, will be located at the existing main collection substation used by GEN-2016-063, the EGF.

The EGF project has an effective GIA with a POI capacity of 200 MW and is making 200 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 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, GEN-2016-063 (EGF) is an active interconnection request at the same POI (G16-063-TAP bus on the Sunnyside to Hugo 345 kV line) with a queue status of "IA FULLY EXECUTED/ON SCHEDULE". GEN-2016-063 is a wind farm, has a maximum summer and winter queue capacity of 200 MW, and has Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS).

GEN-2016-063, the EGF, was originally studied as part of Group 14 in the DISIS-2016-001-1 study. Figure 2-1 shows the power flow model single line diagram for the EGF configuration.

The GEN-2020-SR3 proposed configuration consists of 64 x Power Electronics FP3510M2 3.267 MW batteries for total capacity of 209.09 MW as shown in Table 2-1 below along with the EGF details. As the requested Surplus Interconnection Service is for 200 MW, the injection amount of GEN-2020-SR3 must be limited to 200 MW at the POI. The combined generation from both the SGF and the EGF may not exceed 200 MW at the POI, which is the total Interconnection Service amount currently granted to the EGF. GEN-2020-SR3 includes the use of a Power Plant Controller (PPC) to limit the power injection as required. The proposed GEN-2020-SR3 configuration is captured in Figure 2-2 and Table 2-2 below.

Table 2-1: EGF & SGF Configuration

Request	Capacity (MW)	Surplus Generator Configuration	Point of Interconnection
GEN-2020-SR3 (SGF)	200	64 x Power Electronics FP3510M2 3.267 MW = 209.09 PPC to limit POI to 200MW	Tap on Sunnyside (515136) to Hugo (521157) 345 kV (G16-063-TAP 560088)
GEN-2016-063 (EGF)	200	100 x Vestas V110 2.0MW = 200 MW	Tap on Sunnyside (515136) to Hugo (521157) 345 kV (G16-063-TAP 560088)

Figure 2-1: GEN-2016-063 Single Line Diagram (EGF Configuration)

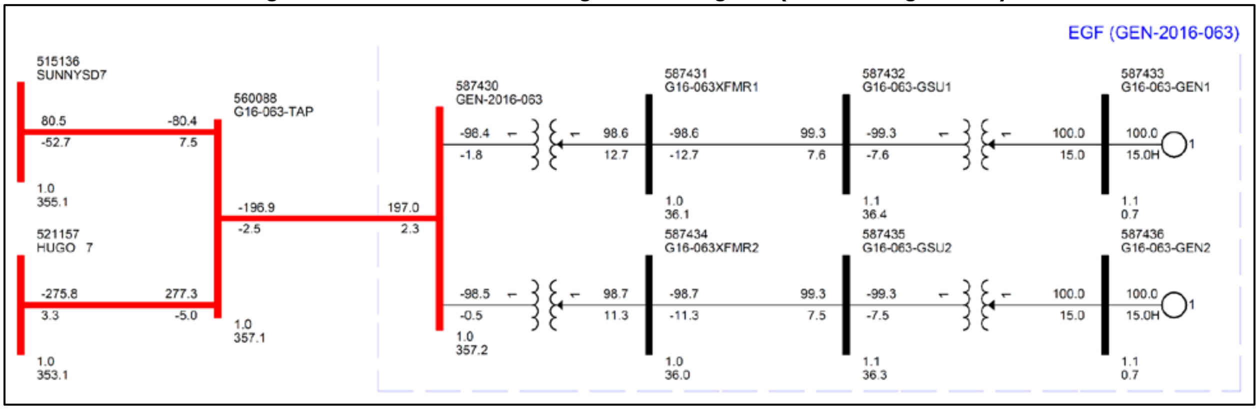


Figure 2-2: GEN-2016-063 & GEN-2020-SR3 Single Line Diagram (EGF & SGF Configuration)

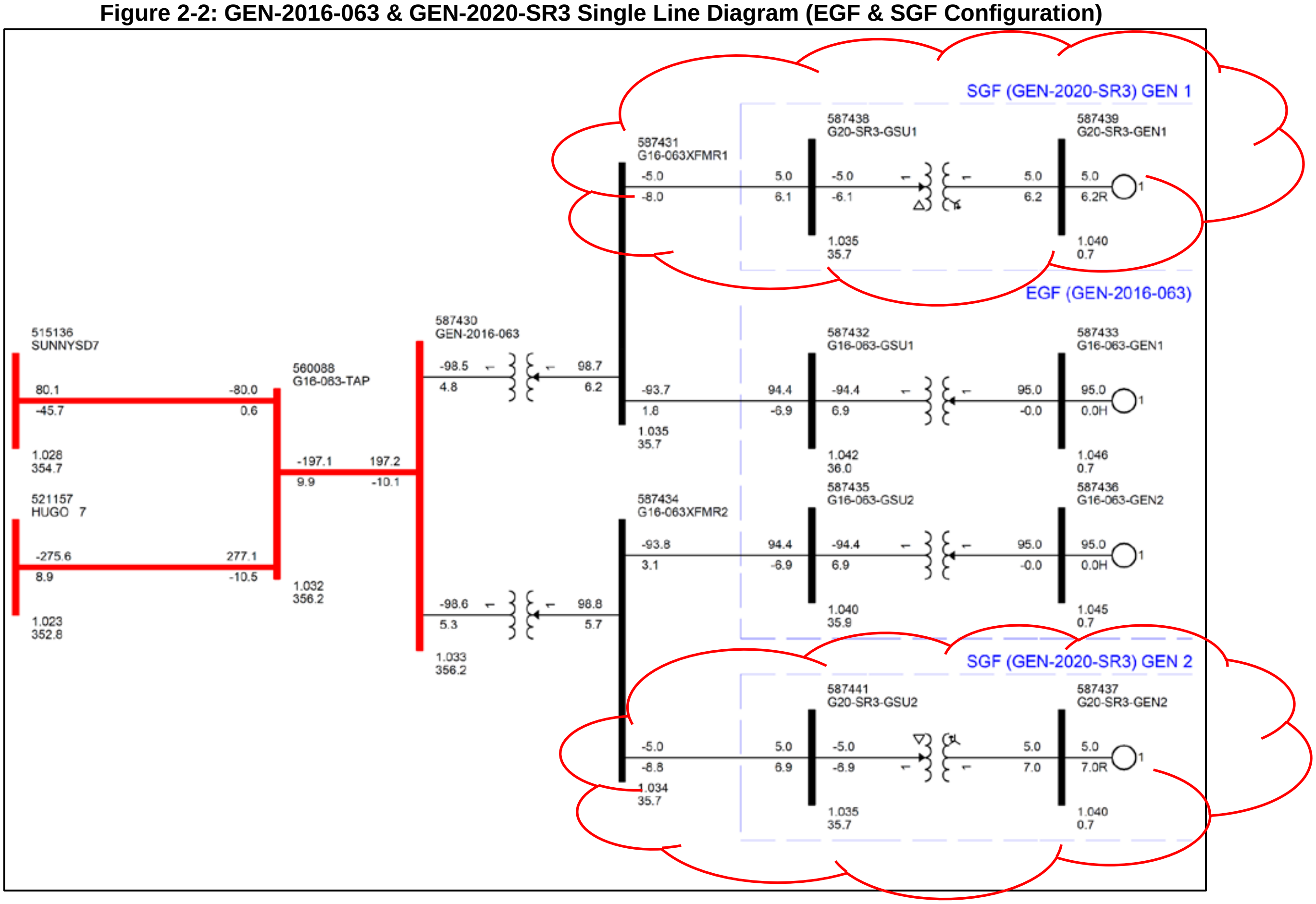


Table 2-2: GEN-2020-SR3 Interconnection Configuration Changes

Facility	GEN-2020-SR3	
Point of Interconnection	Tap on Sunnyside (515136) to Hugo (521157) 345 kV (G16-063-TAP 560088)	
Configuration/Capacity	64 x Power Electronics FP3510M2 3.267 MW = 209.09 MW PPC to limit POI to 200MW	
Existing Generation Interconnection Line (shared with EGF and unchanged)	Length = 0.5 miles R = 0.000082 pu X = 0.000340 pu B = 0.003100 pu	
Existing Main Substation Transformers[1] (shared with EGF and unchanged)	Transformer T1: X = 8.999%, R = 0.134%, Winding MVA = 75 MVA Rating MVA = 125 MVA	Transformer T2: X = 8.998%, R = 0.134%, Winding MVA = 75 MVA Rating MVA = 125 MVA
Equivalent GSU Transformer[1]	X = 8.465%, R = 0.77%, Winding MVA = 116.16 MVA Rating MVA[2] = 116.2 MVA	X = 8.465%, R = 0.77%, Winding MVA = 116.16 MVA Rating MVA[2] = 116.2 MVA
Equivalent Collector Line[3]	R = 0.002215 pu X = 0.002827 pu B = 0.017128 pu	R = 0.002215 pu X = 0.002827 pu B = 0.017128 pu

1) X/R based on Winding MVA, 2) Rating rounded up in PSS/E, 3) all pu are on 100 MVA Base

2.1 POI Injection Comparison

The real power injection at the POI was measured in PSS/E for the EGF configuration and the SGF configuration separately with the other facility offline and disconnected. The difference in the POI injection was then compared for information.

There was an insignificant change (increase of 0.26%) in the real power output at the POI between the EGF configuration and SGF configuration as shown in Table 2-3.

Table 2-3: POI Injection Comparison

Interconnection Request	EGF POI Injection from Project (MW)	SGF POI Injection from Project (MW)	POI Injection Difference %
GEN-2020-SR3	196.93	197.44	0.26%

3.0 Charging Current Compensation Analysis

The charging current compensation analysis was performed for GEN-2020-SR3 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

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

3.2 Results

The results from the analysis showed that the GEN-2020-SR3 (SGF) project needed an approximately 3.75 MVAr shunt reactor at the project substation, to reduce the POI MVAr to zero when the EGF is offline and disconnected. This is a decrease from the 10.1 MVAr found for the EGF alone in the DISIS study[3]. Figure 3-1 illustrates the shunt reactor sizes needed to reduce the POI MVAr to approximately zero for the SGF. The final shunt reactor requirements 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.

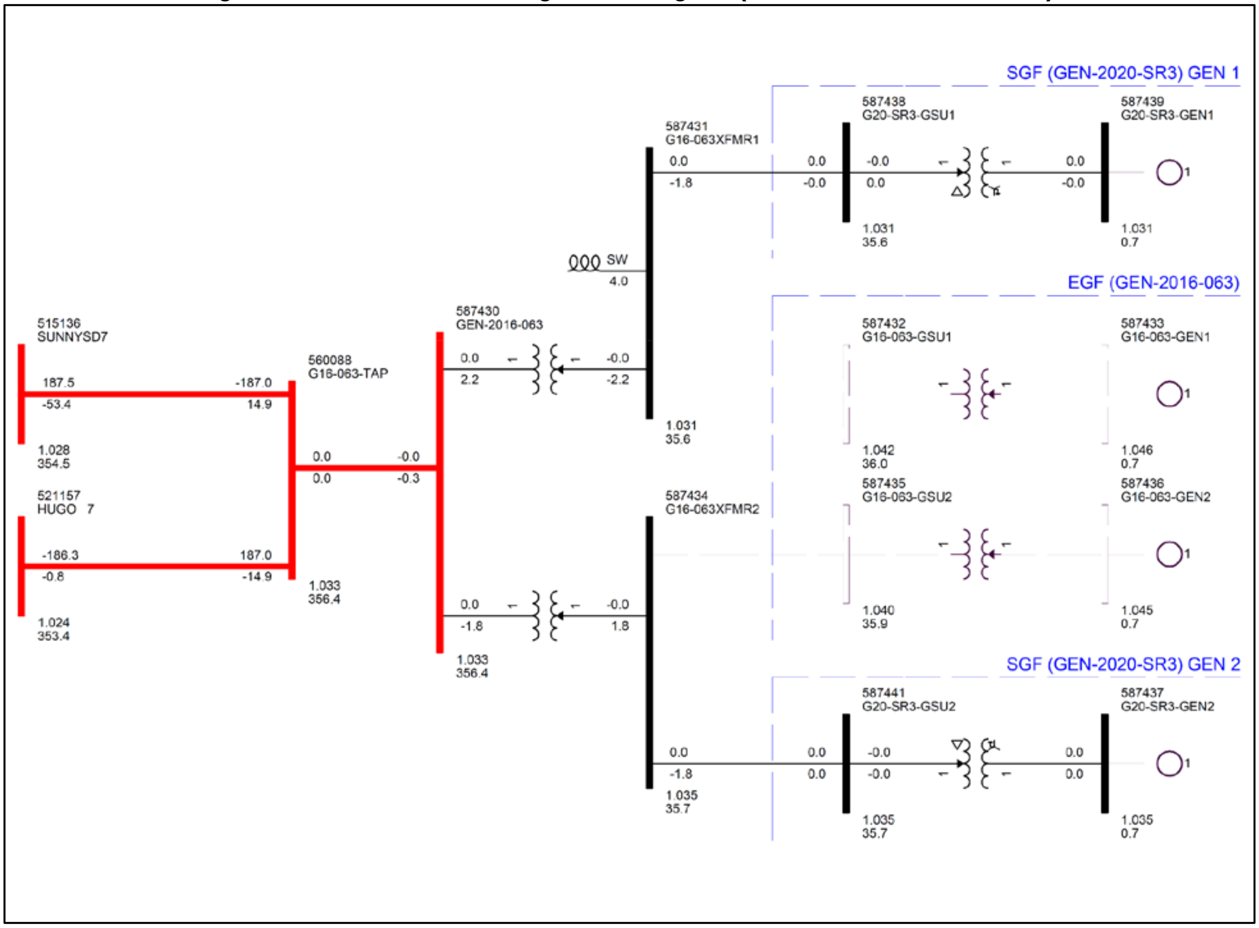
Table 3-1: Shunt Reactor Size for Low Wind Study

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)		
			17WP	18SP	26SP
GEN-2020-SR3 (SGF)	560088	G16-063-TAP 345 kV	3.75	3.75	3.75
GEN-2016-063 (EGF)	560088	G16-063-TAP 345 kV	10.1*	10.1*	10.1*

*Determined in the DISIS-2016-001-1 Report

[3] Definitive Interconnection System Impact Study Report DISIS-2016-001-1, December 22, 2017

Figure 3-1: GEN-2020-SR3 Single Line Diagram (EGF & SGF Shunt Reactor)



4.0 Short Circuit Analysis

A short circuit study was performed using the 2018SP and 2026SP models to determine the maximum available fault current requiring interruption by protective equipment with both the SGF and EGF for each bus in the relevant subsystem, and the amount of increase in maximum fault current due to the addition of the SGF. The detailed results of the short circuit analysis are provided in Appendix B.

4.1 Methodology

The short circuit analysis included applying a 3-phase fault on buses up to 5 levels away from the 345 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels with and without the SGF online. The existing cases were studied with the EGF as dispatched before the SGF was connected. The second stability scenario was also studied with both the EGF and SGF connected and dispatched as determined for the stability study (shown in Section 5.3) to determine the impact of the SGF and the transmission modifications included in this study.

4.2 Results

The results of the short circuit analysis compare the existing DISIS case (EGF online, SGF not included) 2018SP and 2026SP models to the selected dispatch case (EGF = 190 MW, SGF = 10 MW) 2018SP and 2026SP 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 7.85 kA with the EGF and SGF online. The addition of the SGF configuration increased the POI bus fault current by up to 0.15 kA.

The maximum fault current calculated within 5 buses of the POI was less than 40 kA for the 2018SP and 2026SP models respectively. The maximum contribution to three-phase fault current due to the addition of the SGF configuration was about 2.0% and 0.151 kA.

Table 4-1: POI Short Circuit Comparison Results

Case	DISIS EGF Current (kA)	SGF & EGF Current (kA)	Max kA Change	Max %Change
2018SP	7.70	7.85	0.15	1.9%
2026SP	7.68	7.82	0.14	1.8%

Table 4-2: 2018SP Short Circuit Comparison Results

Voltage (kV)	Max. Current (EGF & SGF) (kA)	Max kA Change	Max %Change
69	16.5	0.000	0.0%
138	39.9	0.034	0.2%
345	29.0	0.151	2.0%
Max	**39.9**	**0.151**	**2.0%**

Table 4-3: 2026SP Short Circuit Comparison Results

Voltage (kV)	Max. Current (EGF & SGF) (kA)	Max kA Change	Max %Change
69	16.6	0.000	0.0%
138	39.9	0.026	0.1%
345	28.8	0.140	1.8%
Max	**39.9**	**0.140**	**1.8%**

5.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the GEN-2020-SR3 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 64 x Power Electronics FP3510M2 3.267 MW (REGCAU1) GEN-2020-SR3 SGF generating facility configuration included in the cases. The requested modification included the use of a PPC (REPCAU1) to limit the power injection as required. This stability analysis was performed using PTI's PSS/E version 33.7 software.

Two stability model scenarios were developed using the models from DISIS-2016-002 for Group 14. The first scenario (Scenario 1) was comprised of the SGF online and dispatched to maximum capacity while the EGF generator was offline and the EGF collection system disconnected. The second scenario included both the SGF and EGF online and dispatched. In order to select the appropriate EGF/SGF dispatch combination for the second scenario (Scenario 2), dispatch models in 10 MW increments of the total capacity were created and simulated with a POI fault as shown in Table 5-2 and detailed in Section 5.3. The nearby synchronous machine angle deviation and POI bus voltage deviation results were used to select one dispatch combination where both the EGF and SGF were online for this impact study.

The modified dynamics model data for the GEN-2020-SR3 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 14. In addition, voltages of five (5) buses away from the POI of GEN-2020-SR3 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within this study area including 520 (AEPW), 524 (OKGE), 525 (WFEC), 526 (SPS), 531 (MIDW), 534 (SUNC), 536 (WERE) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

5.2 Fault Definitions

Aneden simulated the faults previously simulated for the GEN-2016-063 (EGF) and selected additional fault events for this study as required. 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 5-1 below. These contingencies were applied to the modified 2017 Winter Peak, 2018 Summer Peak, and the 2026 Summer Peak models.

Table 5-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT01-3PH	P1	3 phase fault on JOHNCO 7 345 kV (514809) to PITTSB-7 345 kV (510907) line CRT 1, near JOHNCO 7. a. Apply fault at the JOHNCO 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT02-3PH	P1	3 phase fault on the JOHNCO 7 345 kV (514809) to JOHNCO 4 138 kV (514808) to JOHNCO11 13.8 kV (514810) XFMR CRT 1, near JOHNCO 7 345 kV. a. Apply fault at the JOHNCO 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT03-3PH	P1	3 phase fault on JOHNCO 7 345 kV (514809) to SUNNYSD7 345 kV (515136) line CRT 1, near JOHNCO 7. a. Apply fault at the JOHNCO 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT04-3PH	P1	3 phase fault on PITTSB-7 345 kV (510907) to VALIANT7 345 kV (510911) line CRT 1, near PITTSB-7. a. Apply fault at the PITTSB-7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT07-3PH	P1	3 phase fault on JOHNCO 4 138 kV (514808) to RUSSET-4 138 kV (515120) line CRT 1, near JOHNCO 4. a. Apply fault at the JOHNCO 4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT08-3PH	P1	3 phase fault on JOHNCO 4 138 kV (514808) to SXMLCKT4 138 kV (515122) line CRT 1, near JOHNCO 4. a. Apply fault at the JOHNCO 4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT09-3PH	P1	3 phase fault on JOHNCO 4 138 kV (514808) to CANEYCK4 138 kV (515150) line CRT 1, near JOHNCO 4. a. Apply fault at the JOHNCO 4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT11-3PH	P1	3 phase fault on the SUNNYSD7 345 kV (515136) to SUNNYSD4 138 kV (515135) to SUNNYSD1 13.8 kV (515762) XFMR CRT 1, near SUNNYSD7 345 kV. a. Apply fault at the SUNNYSD7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT12-3PH	P1	3 phase fault on SUNNYSD7 345 kV (515136) to G16-063-TAP 345 kV (560088) line CRT 1, near SUNNYSD7. a. Apply fault at the SUNNYSD7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT23-3PH	P1	3 phase fault on SUNNYSD7 345 kV (515136) to JOHNCO 7 345 kV (514809) line CRT 1, near SUNNYSD7. a. Apply fault at the SUNNYSD7 bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT69-3PH	P1	3 phase fault on G16-063-TAP 345 kV (560088) to HUGO 7 345 kV (521157) line CRT 1, near G16-063-TAP. a. Apply fault at the G16-063-TAP 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 5-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT70-3PH	P1	3 phase fault on the HUGO 7 345 kV (521157) to HUGO PP4 138 kV (520948) to HUGO TERTA 13.8 kV (521189) XFMR CRT 1, near HUGO 7 345 kV. a. Apply fault at the HUGO 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT71-3PH	P1	3 phase fault on HUGO 7 345 kV (521157) to VALIANT7 345 kV (510911) line CRT 1, near HUGO 7. a. Apply fault at the HUGO 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT74-3PH	P1	3 phase fault on HUGO 7 345 kV (521157) to G16-063-TAP 345 kV (560088) line CRT 1, near HUGO 7. a. Apply fault at the HUGO 7 bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT14-SB	P4	**Stuck Breaker at JOHNCO 7 (514809)** a. Apply single phase fault at JOHNCO 7 bus. b. Clear fault after 16 cycles and trip the following elements c. JOHNCO 7 (514809) - PITTSB-7 (510907) d. JOHNCO 7 345kV (514809) / JOHNCO 4 138 kV (514808) / JOHNCO11 13.8 kV (514810) XFMR CRT 1
FLT15-SB	P4	**Stuck Breaker at JOHNCO 7 (514809)** a. Apply single phase fault at JOHNCO 7 bus. b. Clear fault after 16 cycles and trip the following elements c. JOHNCO 7 (514809) - SUNNYSD7 (515136) d. JOHNCO 7 345kV (514809) / JOHNCO 4 138 kV (514808) / JOHNCO11 13.8 kV (514810) transformer
FLT03-PO1	P6	**Prior Outage of JOHNCO 7 (514809) to PITTSB-7 (510907) line;** 3 phase fault on JOHNCO 7 345 kV (514809) to SUNNYSD7 345 kV (515136) line CRT 1, near JOHNCO 7. a. Apply fault at the JOHNCO 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT02-PO1	P6	**Prior Outage of JOHNCO 7 (514809) to PITTSB-7 (510907) line;** 3 phase fault on the JOHNCO 7 345 kV (514809) to JOHNCO 4 138 kV (514808) to JOHNCO11 13.8 kV (514810) XFMR CRT 1, near JOHNCO 7 345 kV. a. Apply fault at the JOHNCO 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT02-PO2	P6	**Prior Outage of JOHNCO 7 (514809) to SUNNYSD7 (515136) line;** 3 phase fault on the JOHNCO 7 345 kV (514809) to JOHNCO 4 138 kV (514808) to JOHNCO11 13.8 kV (514810) XFMR CRT 1, near JOHNCO 7 345 kV. a. Apply fault at the JOHNCO 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT23-PO3	P6	**Prior Outage of SUNNYSD7 (515136) to G16-063-TAP (560088) line;** 3 phase fault on SUNNYSD7 345 kV (515136) to JOHNCO 7 345 kV (514809) line CRT 1, near SUNNYSD7. a. Apply fault at the SUNNYSD7 bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT74-PO4	P6	**Prior Outage of HUGO 7 (521157) to VALIANT7 (510911) line;** 3 phase fault on HUGO 7 345 kV (521157) to G16-063-TAP 345 kV (560088) line CRT 1, near HUGO 7. a. Apply fault at the HUGO 7 bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 5-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT12-PO5	P6	**Prior Outage of SUNNYSD7 345kV (515136) / SUNNYSD4 138 kV (515135) /SUNYSD 1 13.8 kV (515405) transformer;** 3 phase fault on SUNNYSD7 345 kV (515136) to G16-063-TAP 345 kV (560088) line CRT 1, near SUNNYSD7. a. Apply fault at the SUNNYSD7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9001-3PH	P1	3 phase fault on G16-063-TAP 345 kV (560088) to SUNNYSD7 345 kV (515136) line CRT 1, near G16-063-TAP. a. Apply fault at the G16-063-TAP 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	P1	3 phase fault on JOHNCO 7 345 kV (514809) to GEN-2015-036 345 kV (584780) line CRT 1, near JOHNCO 7. a. Apply fault at the JOHNCO 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **TRIP Generator G15-036-GEN1 (584783).** **TRIP Generator G15-036-GEN2 (584786).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9003-3PH	P1	3 phase fault on SUNNYSD7 345 kV (515136) to TERRYRD7 345 kV (511568) line CRT 1, near SUNNYSD7. a. Apply fault at the SUNNYSD7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9004-3PH	P1	3 phase fault on TERRYRD7 345 kV (511568) to L.E.S.-7 345 kV (511468) line CRT 1, near TERRYRD7. a. Apply fault at the TERRYRD7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1	3 phase fault on TERRYRD7 345 kV (511568) to RUSHSPR7 345 kV (511571) line CRT 1, near TERRYRD7. a. Apply fault at the TERRYRD7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **TRIP Generator G14-057-GEN1 (584073).** **TRIP Generator G15-092-GEN1 (585283).** **TRIP Generator G15-092-GEN2 (585284).** **TRIP Generator G15-045-GEN1 (584862).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9006-3PH	P1	3 phase fault on VALIANT7 345 kV (510911) to PITTSB-7 345 kV (510907) line CRT 1, near VALIANT7. a. Apply fault at the VALIANT7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9007-3PH	P1	3 phase fault on VALIANT7 345 kV (510911) to NWTXARK7 345 kV (508072) line CRT 1, near VALIANT7. a. Apply fault at the VALIANT7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	P1	3 phase fault on VALIANT7 345 kV (510911) to LYDIA 345 kV (508298) line CRT 1, near VALIANT7. a. Apply fault at the VALIANT7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 5-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9009-3PH	P1	3 phase fault on VALIANT7 345 kV (510911) to GEN-2016-129 345 kV (588200) line CRT 1, near VALIANT7. a. Apply fault at the VALIANT7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. **TRIP Generator G16-129-GEN1 (588203).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9010-3PH	P1	3 phase fault on the VALIANT7 345 kV (510911) to VALIANT4 138 kV (510918) to VALN3-1 13.8 kV (510939) XFMR CRT 1, near VALIANT7 345 kV. a. Apply fault at the VALIANT7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9011-3PH	P1	3 phase fault on HUGO PP4 138 kV (520948) to VALIANT 138 kV (510918) line CRT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT70-PO3	P6	**Prior Outage of SUNNYSD7 (515136) to G16-063-TAP (560088) line;** 3 phase fault on the HUGO 7 345 kV (521157) to HUGO PP4 138 kV (520948) to HUGO TERTA 13.8 kV (521189) XFMR CRT 1, near HUGO 7 345 kV. a. Apply fault at the HUGO 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT71-PO3	P6	**Prior Outage of SUNNYSD7 (515136) to G16-063-TAP (560088) line;** 3 phase fault on HUGO 7 345 kV (521157) to VALIANT7 345 kV (510911) line CRT 1, near HUGO 7. a. Apply fault at the HUGO 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT11-PO6	P6	**Prior Outage of G16-063-TAP 345 kV (560088) to HUGO 7 345 kV (521157) line;** 3 phase fault on the SUNNYSD7 345 kV (515136) to SUNNYSD4 138 kV (515135) to SUNNYSD1 13.8 kV (515762) XFMR CRT 1, near SUNNYSD7 345 kV. a. Apply fault at the SUNNYSD7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT23-PO6	P6	**Prior Outage of G16-063-TAP 345 kV (560088) to HUGO 7 345 kV (521157) line;** 3 phase fault on SUNNYSD7 345 kV (515136) to JOHNCO 7 345 kV (514809) line CRT 1, near SUNNYSD7. a. Apply fault at the SUNNYSD7 bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9003-PO6	P6	**Prior Outage of G16-063-TAP 345 kV (560088) to HUGO 7 345 kV (521157) line;** 3 phase fault on SUNNYSD7 345 kV (515136) to TERRYRD7 345 kV (511568) line CRT 1, near SUNNYSD7. a. Apply fault at the SUNNYSD7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT1001-SB	P4	**Stuck Breaker at SUNNYSD7 (515136)** a. Apply single phase fault at SUNNYSD7 bus. b. Clear fault after 16 cycles and trip the following elements c. SUNNYSD7 (515136) - G16-063-TAP (560088) d. SUNNYSD7 345kV (515136) / SUNNYSD4 138 kV (515135) / SUNYSD 1 13.8 kV (515405) transformer
FLT1002-SB	P4	**Stuck Breaker at SUNNYSD7 (515136)** a. Apply single phase fault at SUNNYSD7 bus. b. Clear fault after 16 cycles and trip the following elements c. SUNNYSD7 (515136) - JOHNCO 7 (514809) d. SUNNYSD7 345kV (515136) / SUNNYSD4 138 kV (515135) / SUNYSD 1 13.8 kV (515762) transformer

Table 5-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT1003-SB	P4	**Stuck Breaker at HUGO 7 (521157)** a. Apply single phase fault at HUGO 7 bus. b. Clear fault after 16 cycles and trip the following elements c. HUGO 7 (521157) - VALIANT7 (510911) d. HUGO 7 345 kV (521157) to HUGO PP4 138 kV (520948) to HUGO TERTA 13.8 kV (521189) XFMR CRT 1
FLT1004-SB	P4	**Stuck Breaker at JOHNCO 7 (514809)** a. Apply single phase fault at JOHNCO 7 bus. b. Clear fault after 16 cycles and trip the following elements c. JOHNCO 7 (514809) - GEN-2015-036 (584780) d. JOHNCO 7 (514809) - SUNNYSD7 (515136)
FLT1005-SB	P4	**Stuck Breaker at JOHNCO 7 (514809)** a. Apply single phase fault at JOHNCO 7 bus. b. Clear fault after 16 cycles and trip the following elements c. JOHNCO 7 (514809) - PITTSB-7 (510907) d. JOHNCO 7 (514809) - GEN-2015-036 (584780)

5.3 Dispatch Test Results

In order to determine the appropriate EGF/SGF dispatch combination for the second scenario, dispatch models in 10 MW increments of the total capacity were created and simulated with a POI fault. The dispatch scenarios tested are shown in Table 5-2. The nearby synchronous machine angle deviation and POI bus voltage deviation results were used to select the worst-case dispatch combination with both the EGF and SGF online for this impact study.

Table 5-2: Scenario 2 Dispatch Tests

Dispatch Scenarios		
GEN-2016-063 EGF (MW)	GEN-2020-SR3 SGF (MW)	EGF + SGF (MW)
10	190	200
20	180	200
30	170	200
40	160	200
50	150	200
60	140	200
70	130	200
80	120	200
90	110	200
100	100	200
110	90	200
120	80	200
130	70	200
140	60	200
150	50	200
160	40	200
170	30	200
180	20	200
190	10	200

Figure 5-1: Dispatch Test Voltage Recovery

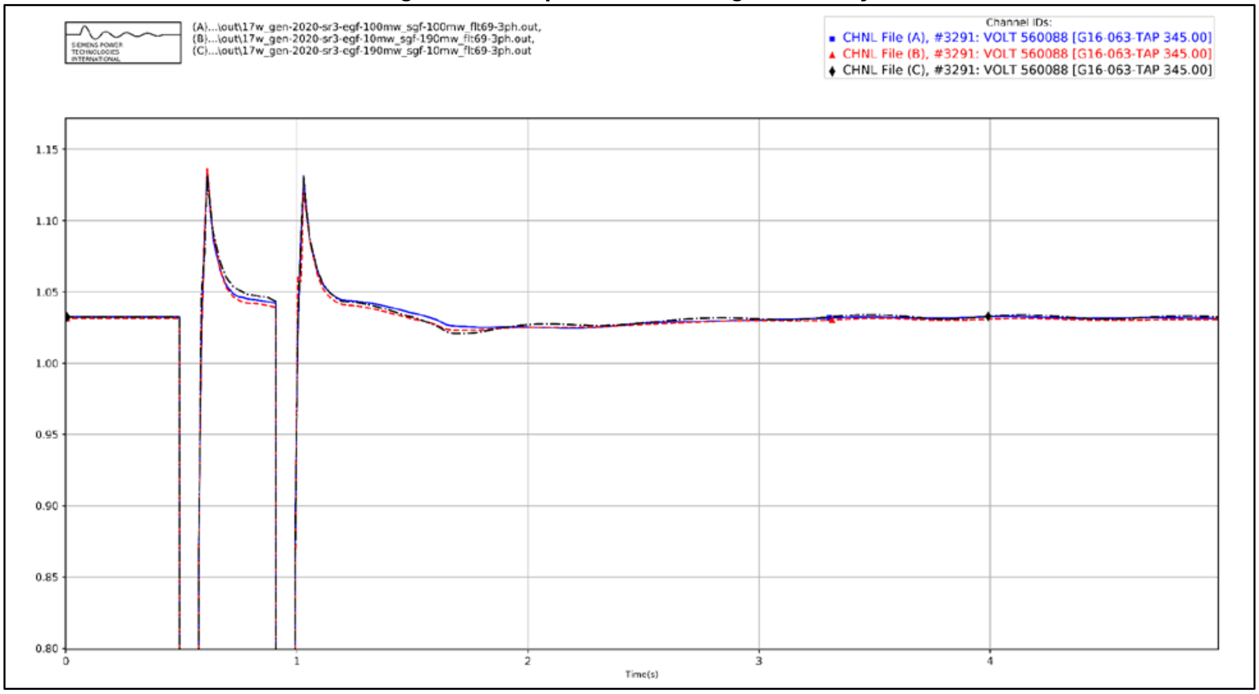


Figure 5-2: Dispatch Test Rotor Angle Deviation

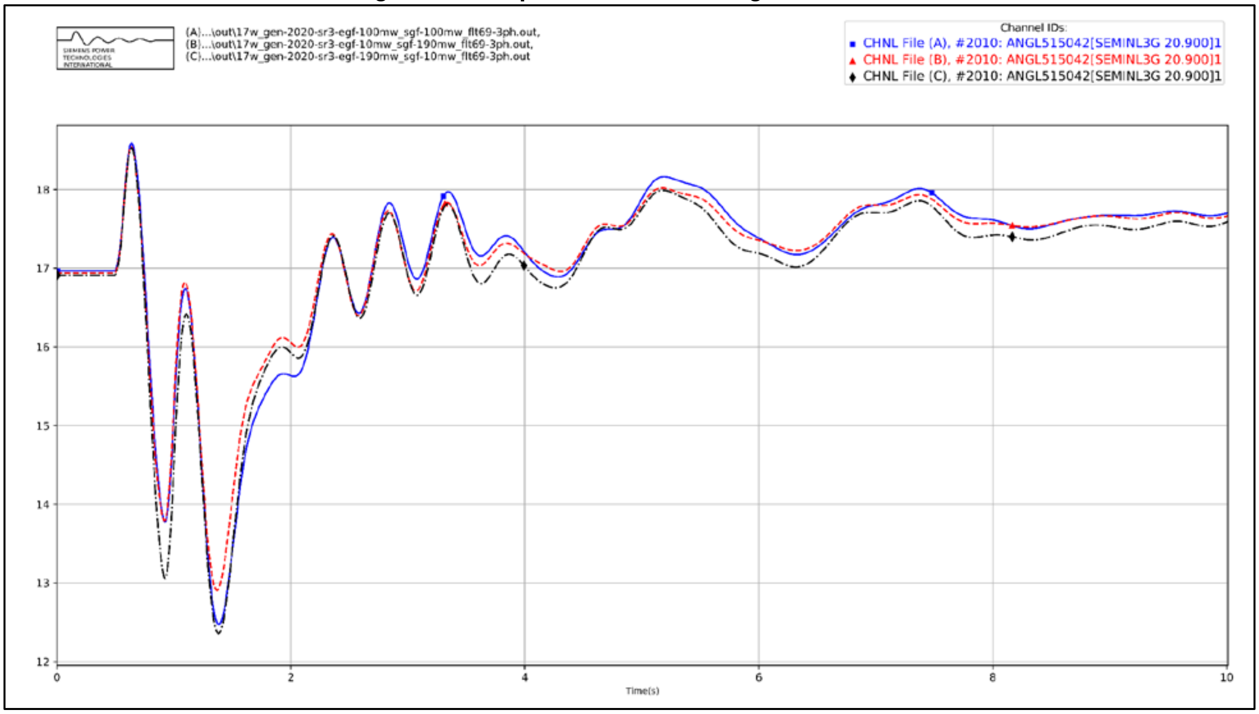


Figure 5-1 and Figure 5-2 show the nearby synchronous machine voltage recovery and rotor angle deviation respectively for three of the tested dispatch scenarios. The scenario in which the EGF is online at 190 MW and the SGF is online at 10 MW was selected as Scenario 2 based on these results.

5.4 Scenario 1 Results

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

Table 5-3: GEN-2020-SR3 Scenario 1 (EGF Offline, SGF 100%)

Fault ID	17WP			18SP			26SP		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable
FLT01-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT08-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT09-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT11-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT12-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT23-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT69-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT70-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT71-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT74-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT14-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT15-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT23-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT70-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT71-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT74-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT12-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT11-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT23-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

There were no damping or voltage recovery violations 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.

5.1 Scenario 2 Results

Table 5-4 shows the results of the fault events simulated for each of the three modified cases in Scenario 2. The associated stability plots are provided in Appendix D.

Table 5-4: GEN-2020-SR3 Scenario 2 (EGF = 190 MW, SGF = 10 MW)

Fault ID	17WP			18SP			26SP		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable
FLT01-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT08-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT09-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT11-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT12-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT23-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT69-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT70-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT71-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT74-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT14-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT15-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT23-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT70-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT71-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT74-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT12-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT11-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT23-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

There were no damping or voltage recovery violations 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.

The Transmission Owner did not identify any Interconnection Facilities required for the Surplus Interconnection Request at the time of posting. A Surplus Interconnection Service Facility Study will not be required per the Transmission Owner.

6.2 Network Upgrades

This study did not identify any Network Upgrades required by the addition of the SGF.

The Transmission Owner did not identify any Network Upgrades required for the Surplus Interconnection Request at the time of posting. A Surplus Interconnection Service Facility Study will not be required per the Transmission Owner.

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-2020-SR3 may utilize the requested 200 MW of Surplus Interconnection Service provided by GEN-2016-063.

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 200 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 will need to be reviewed by SPP and the TO and documented in Appendix C of the GIA.

8.0 Conclusions

The GEN-2020-SR3 Interconnection Customer has requested a Surplus Interconnection Service Impact Study (Study) for GEN-2020-SR3 (SGF) to utilize the Surplus Interconnection Service provided by GEN-2016-063 (EGF) at its existing the point of interconnection (POI), the G16-063-TAP bus on the Sunnyside to Hugo 345 kV line.

The scope of this study included a charging current compensation analysis, short circuit analysis, and dynamic stability analysis. Since the EGF and SGF are both non-synchronous fuel types, SPP determined that power flow analysis should not be performed as the EGF was studied previously under the required reliability conditions.

The results of the charging current compensation analysis performed using the 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak models showed that the GEN-2020-SR3 SGF project needed an approximately 3.75 MVAr shunt reactor at the project substation, to reduce the POI MVAr to zero with the EGF offline and disconnected. This is a decrease from the 10.1 MVAr found for the EGF alone in the DISIS study[4]. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind or no-wind 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 existing DISIS case (EGF online, SGF not included) 2018SP and 2026SP models to the SGF study case (EGF and SGF online) 2018SP and 2026SP models. The maximum contribution to three-phase fault currents in the immediate systems due to the addition of the SGF was not greater than 0.151 kA. All three-phase fault current levels within 5 buses of the POI with the EGF and SGF generators online were below 40 kA for the 2018SP models and 2026SP models.

The dynamic stability analysis was performed using the three DISIS-2016-002 models 2017 Winter Peak, 2018 Summer Peak, 2026 Summer Peak with two scenarios. In the first scenario, the SGF was online at 200 MW while the EGF was offline with the collection system disconnected. Aneden and SPP selected the second scenario based on a combination of SGF and EGF dispatch scenarios with the project dispatches varied by 10 MW increments of the total capacity of 200 MW. The resulting selected worst-case scenario include a combination of the SGF dispatched to 10 MW and the EGF to 190 MW. Up to 43 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 no damping or voltage recovery violations 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.

[4] Definitive Interconnection System Impact Study Report DISIS-2016-001-1, December 22, 2017

The results of the study showed that the Surplus Interconnection Service Request by GEN-2020-SR3 did not negatively impact the reliability of the Transmission System. There were no additional Interconnection Facilities or Network Upgrades identified by the analyses and the Transmission Owner did not identify any Interconnection Facilities required for the Surplus Interconnection Request at the time of posting. A Surplus Interconnection Service Facility Study will not be required per the Transmission Owner.

SPP has determined that GEN-2020-SR3 may utilize the requested 200 MW of Surplus Interconnection Service provided by GEN-2016-063. The combined generation from both the SGF and the EGF may not exceed 200 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 will need to be reviewed by SPP and the TO and documented in Appendix C of the 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.