GEN-2026-SR2

SURPLUS INTERCONNECTION SYSTEM IMPACT STUDY

By SPP Generator Interconnection

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EXECUTIVE SUMMARY

Southwest Power Pool (SPP) was requested by Interconnection Customer (IC) to perform a Surplus Service Impact Study (Study) for GEN-2026-SR2 to utilize the Surplus Interconnection Service being made available by the GEN-2010-009 project at its existing Point of Interconnection (POI), the Buckner County 345 kV substation in the Sunflower (SUNC) control area.

GEN-2026-SR2, the proposed Surplus Generating Facility (SGF), will connect to the existing GEN-2010-009 Existing Generating Facility (EGF) and share the existing tie-line to the POI.

GEN-2010-009, the Existing Generating Facility (EGF), has an effective Generator Interconnection Agreement (GIA) with a combined POI capacity of 165.6 MW and is making 165.6 MW of Surplus Interconnection Service available at its POI. Per the SPP Open Access Transmission Tariff (SPP Tariff), the amount of Surplus Interconnection Service available to the SGF is limited by the amount of Interconnection Service granted to the EGF at the same POI. In addition, the Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring Network Upgrades except those specified in the SPP Tariff[1].

The proposed SGF configuration consists of 66 x FP4200 BESS inverters operating at 2.51 MW for a total assumed dispatch of 165.6 MW. The inverters are rated at 2.565 MW, thus the generating capability of the SGF (169.29 MW) exceeds its requested Surplus Interconnection Service of 165.6 MW. The injection amount of the SGF must be limited to 165.6 MW at the POI. The combined generation from both the SGF and the EGF may not exceed 165.6 MW at the POI. GEN-2026-SR2 includes the use of a power plant controller (PPC) to limit the power injection as required. The SGF and EGF information is shown in Table 1.

The detailed SGF configuration is captured in Table 2.

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

Table 1: EGF & SGF Configuration

REQUEST	POINT OF INTERCONNECTION	EXISTING GENERATOR CONFIGURATION	GIA CAPACITY (MW)
GEN-2026-SR2 (SGF)	Buckner County 345 kV Substation (531501)	66 x FP4200 BESS inverters	165.6
GEN-2010-009 (EGF)	Buckner County 345 kV Substation (531501)	72 x SWT-2.3 MVA	165.6

Table 2: SGF Interconnection Configuration

FACILITY	SGF CONFIGURATION
Point of Interconnection	Buckner County 345 kV (531501)
Configuration/Capacity	66 x FP4200 BESS 3.78 MVA = 165.6 MW
Generation Interconnection Line (Shared with the EGF per the DISIS-2022-001 RESTUDY models and unchanged)	Length = 1 miles R = 0.000400 pu X = 0.004800 pu B = 0.009100 pu
Main Substation Transformer[1] (Shared with the EGF per the DISIS-2022-001 RESTUDY models and unchanged)	R = 0.0089951 pu X = 0.089951 pu Winding MVA = 400 MVA Rating MVA = 400 MVA
Equivalent GSU Transformer[1]	Gen Equivalent Qty: 66 R = 0.008697 pu X = 0.0895791 pu Winding MVA = 4.2 MVA Rating MVA = 4.2 MVA
Generator Dynamic Model[2] & Power Factor	"PEPPC_VS0105t Leading and Lagging = ±0.95"
Reactive Power Devices (Shared with the EGF per the DISIS-	N/A

2022-001 RESTUDY models and unchanged)	

SPP determined that steady-state analysis was not required because the addition of the SGF does not increase the maximum active power output of 165.6 MW. In addition, the EGF was previously studied at maximum Interconnection Service under all necessary reliability conditions.

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

SPP performed the analyses using the study data provided for the SGF and the DISIS-2022-001 RESTUDY study models:

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

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

The results of the reactive power analysis using the 25SP model showed that the SGF project requires a shunt reactor of 3.9 MVA at the project substation to reduce the POI MVAr to zero. The information gathered from the reactive power analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator (TOP). The applicable reactive power requirements will be further reviewed by the TO and/or TOP.

The short circuit analysis was performed using the 25SP stability model modified for short circuit analysis. The results from the short circuit analysis compared the 25SP model with the EGF online and SGF not connected to the SGF study model (EGF and SGF online). The maximum contribution to three-phase fault currents in the immediate transmission systems due to the addition of the SGF was not greater than 0.247 kA. The maximum three-phase fault current level within five buses of the POI with the EGF and SGF generators online was below 40 kA for the 25SP model.

The dynamic stability analysis was performed using Siemens PTI PSS/E version 34.8.0 software for the two modified study models: 25SP and 25WP, each with two dispatch scenarios. 59 events were simulated, which included three-phase faults and single-line-to-ground stuck breaker faults.

[2] Power System Simulator for Engineering

- Scenario 1: SGF at maximum assumed dispatch, 165.6 MW, and EGF disconnected.
- Scenario 2: SGF at assumed dispatch, 130.5 MW, and EGF dispatched with the remaining 35.1 MW for a total combination of 165.6 MW.

The results of the dynamic stability analysis showed several existing base case issues that were found in both the original DISIS-2022-001 RESTUDY model and in the model with GEN-2026-SR2 included. These issues were not attributed to the GEN-2026-SR2 surplus request and are detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2026-SR2 surplus request observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

The results of the study showed that the Surplus Interconnection Service Request by GEN-2026-SR2 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-2026-SR2 may utilize the requested 165.6 MW of Surplus Interconnection Service being made available by the EGF. The combined generation from both the SGF and the EGF may not exceed 165.6 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 Interconnection Service amount listed in the EGF's GIA. The monitoring and control scheme may be reviewed by the TO and documented in Appendix C of the SGF GIA.

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

It is likely that the customer may be required to reduce its generation output to 0 MW in real-time, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Nothing in this study should be construed as a guarantee of transmission service or delivery rights. If the customer wishes to obtain deliverability to final customers, a separate request for transmission service must be requested on Southwest Power Pool's OASIS by the customer.

SCOPE OF STUDY

Southwest Power Pool (SPP) was requested by Interconnection Customer (IC) to perform a Surplus Service Impact Study (Study) for GEN-2026-SR2, the Surplus Generating Facility (SGF). A Surplus Service Impact Study is performed to identify the impact of the Surplus Interconnection Service on the transmission system reliability and any additional Interconnection Facilities necessary pursuant to the SPP Generator Interconnection Procedures ("GIP") contained in Attachment V Section 3.3 of the SPP Open Access Transmission Tariff (SPP Tariff). The amount of Surplus Interconnection Service available to the SGF is limited by the amount of Interconnection Service granted to the existing interconnection customer for the Existing Generating Facility (EGF) at the same POI. The Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades except those specified in the SPP Tariff[3]. The required scope of the study is dependent upon the EGF and SGF specifications. The criteria sections below include the basis of the analyses included in the scope of study.

All analyses were performed using the Siemens PTI PSS/E®[4] version 34 software. The results of each analysis are presented in the following sections.

REACTIVE POWER ANALYSIS

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

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

[4] Power System Simulator for Engineering

SHORT-CIRCUIT ANALYSIS

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

STABILITY ANALYSIS

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

STEADY-STATE ANALYSIS

The steady-state (thermal/voltage) analyses may be performed as necessary to ensure that all required reliability conditions are studied. If the EGF was subject to SPP powerflow study, yet 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 may require a steady-state analysis to study impacts resultant from changes in dispatch to all equal and lower queued requests. The steady-state analyses will identify any additional Interconnection Facilities and Network Upgrades necessary.

NECESSARY INTERCONNECTION FACILITIES & NETWORK UPGRADES

The SPP Tariff[5] states that the reactive power, short circuit/fault duty, stability, and steady-state analyses (where applicable) for the Surplus Interconnection Service will identify any additional Interconnection Facilities necessary. In addition, the analyses will determine if any Network Upgrades are required for mitigation. The Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades unless (a) those additional Network Upgrades are either (1) located at the Point of Interconnection substation and at the same voltage level as the Generating Facility with an effective GIA, or (2) are System Protection Facilities; and (b) there are no material adverse impacts on the cost or timing of any Interconnection Requests pending at the time the Surplus Interconnection Service request is submitted.

STUDY LIMITATIONS

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

[5] SPP Open Access Transmission Tariff Section 3.3.4.1

SURPLUS INTERCONNECTION SERVICE REQUEST

The GEN-2026-SR2 Interconnection Customer has requested a Surplus Interconnection Service Impact Study (Study) for GEN-2026-SR2 to utilize the Surplus Interconnection Service being made available by the GEN-2010-009 project at its existing Point of Interconnection (POI), the Buckner County 345 kV Substation in the Sunflower (SUNC) control area.

GEN-2026-SR2, the proposed SGF, will connect to the existing GEN-2010-009 main collection substation utilizing its own main power transformer separate from the EGF.

GEN-2010-009, the EGF, has an effective Generation Interconnection Agreement (GIA) with a combined POI capacity of 165.6 MW and is making 165.6 MW of Surplus Interconnection Service available at its POI. Per the SPP Tariff the amount of Surplus Interconnection Service available to the SGF is limited by the amount of Interconnection Service granted to the EGF at the same POI. In addition, the Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades except those specified in the SPP Tariff.

At the time of the posting of this report, GEN-2010-009 (EGF) are active existing projects at the same POI (Buckner County 345 kV) with a queue status of "IA FULLY EXECUTED/COMMERCIAL OPERATION". The GEN-2010-009 project is a solar farm, has a maximum combined summer and winter queue capacity of 165.6 MW, and has Energy Resource Interconnection Service (ERIS). Figure 1 shows the power flow model single line diagram for the EGF configuration.

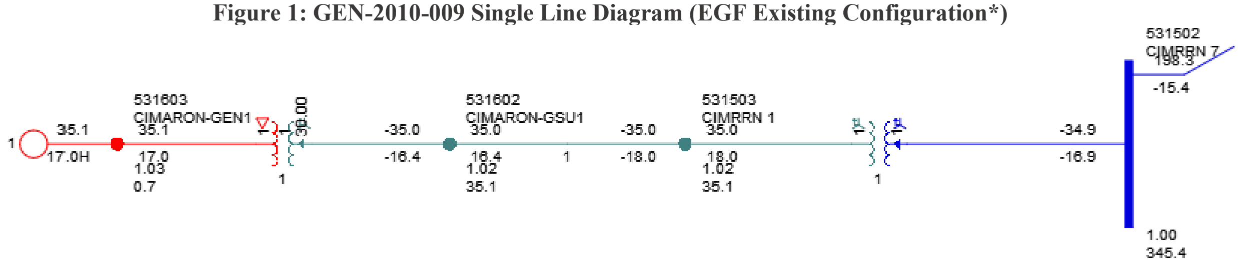
The proposed SGF configuration consists of 66 x FP4200 BESS inverters operating at 2.51 MW for a total assumed dispatch of 165.6 MW. The inverters are rated at 2.565 MW, thus the generating capability of the SGF (169.29 MW) exceeds its requested Surplus Interconnection Service of 165.6 MW. The injection amount of the SGF must be limited to 165.6 MW at the POI. The combined generation from both the SGF and the EGF may not exceed 165.6 MW at the POI. GEN-2026-SR2 includes the use of a power plant controller (PPC) to limit the power injection as required. The SGF and EGF information is shown in Table 3.

Table 3: EGF & SGF Configuration

REQUEST	POINT OF INTERCONNECTION	EXISTING GENERATOR CONFIGURATION	GIA CAPACITY (MW)
GEN-2026-SR2 (SGF)	Buckner County 345 kV Substation (531501)	66 x FP4200 BESS inverters	165.6
GEN-2010-009 (EGF)	Buckner County 345 kV Substation (531501)	72 x SWT-2.3 MVA	165.6

The proposed detailed SGF configuration is captured in Figure 2 and Table 4.

Figure 1: GEN-2010-009 Single Line Diagram (EGF Existing Configuration*)



*based on the DISIS-2022-001 RESTUDY 25SP stability models

Figure 2: GEN-2010-009& GEN-2026-SR2 Single Line Diagram (EGF & SGF Configuration)

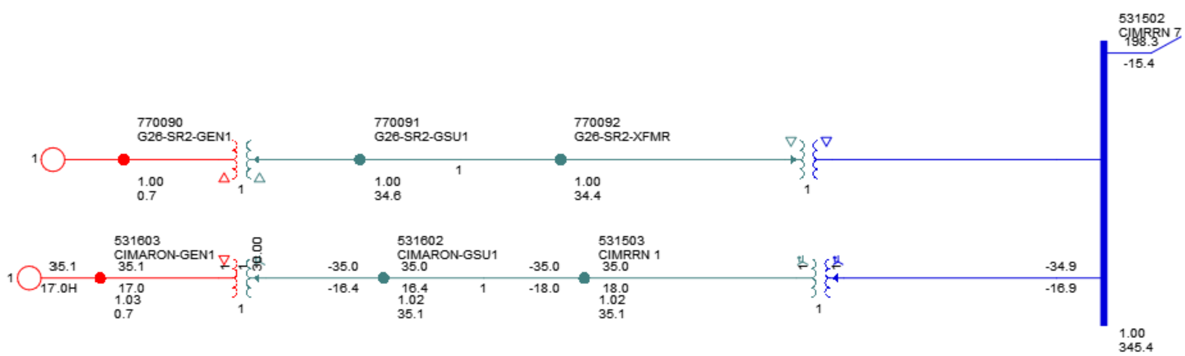


Table 4: SGF Interconnection Configuration

FACILITY	SGF CONFIGURATION
Point of Interconnection	Buckner County 345 kV (531501)
Configuration/Capacity	66 x FP4200 BESS 3.78 MVA = 165.6 MW
Generation Interconnection Line (Shared with the EGF per the DISIS-2022-001 RESTUDY models and unchanged)	Length = 1 miles R = 0.000400 pu X = 0.004800 pu B = 0.009100 pu
Main Substation Transformer[1] (Shared with the EGF per the DISIS-2022-001 RESTUDY models and unchanged)	R = 0.0089951 pu X = 0.089951 pu Winding MVA = 400 MVA Rating MVA = 400 MVA
Equivalent GSU Transformer[1]	Gen Equivalent Qty: 66 R = 0.008697 pu X = 0.0895791 pu Winding MVA = 4.2 MVA Rating MVA = 4.2 MVA
Generator Dynamic Model[2] & Power Factor	"PEPPC_VS0105t Leading and Lagging = ±0.95"
Reactive Power Devices (Shared with the EGF per the DISIS-2022-001 RESTUDY models and unchanged)	N/A

REACTIVE POWER ANALYSIS

The reactive power analysis was performed for GEN-2026-SR2 to determine the capacitive charging effects due to the SGF during reduced generation conditions (unsuitable wind speeds, unsuitable solar irradiance, insufficient state of charge, idle conditions, curtailment, etc.) at the generation site, and to size shunt reactors that would reduce the project reactive power contribution to the POI to approximately zero.

METHODOLOGY AND CRITERIA

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

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

SPP performed the reactive power analysis using the SGF data based on the 25SP DISIS-2022-001 RESTUDY stability study model.

RESULTS

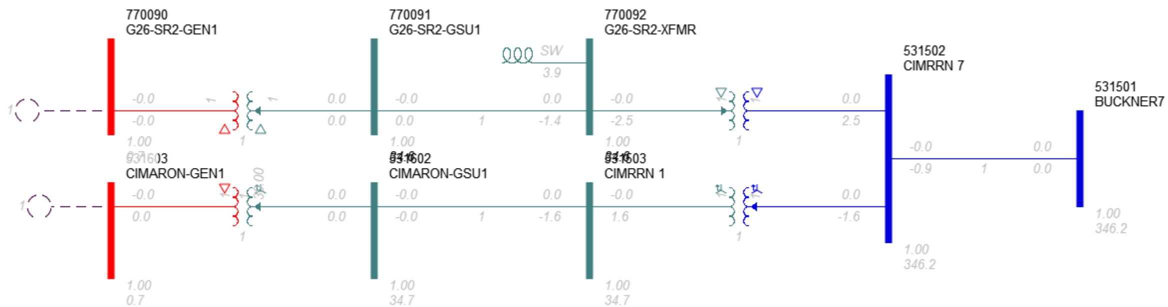
Per the methodology described above, the shunt size was determined for the EGF prior to calculating the shunt reactor size for the SGF. The shunt size was found to be a 3.6 MVAr reactor for the EGF to reduce the POI MVAr to approximately zero. Note that the EGF shunt value is for the SGF reactive size determination only and not for sizing the predetermined EGF reactive requirements.

The results from the analysis showed that the SGF did not need a shunt reactor at the project substation to reduce the POI MVAr to zero with the pre-determined shunt for the EGF in-service.

Figure 3 illustrates that no additional compensation was necessary to offset the capacitive effect on the transmission network caused by the project during reduced generation conditions.

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

Figure 3: GEN-2026-SR2 Single Line Diagram (Shunt Sizes)



SHORT CIRCUIT ANALYSIS

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

METHODOLOGY

The short circuit analysis included applying a three-phase fault on buses up to five levels away from the 345 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels in the transmission system with and without the SGF online. The first scenario was studied with both the SGF and EGF in service. In the second scenario the SGF was disconnected while the EGF was online to determine the impact of the SGF.

SPP created a short circuit model using the 25SP DISIS-2022-001 RESTUDY stability study model by adjusting the SGF short circuit parameters consistent with the submitted data. The adjusted parameters used in the short circuit analysis are shown in Table 5. No other changes were made to the model.

Table 5: Short Circuit Model Parameters*

PARAMETER	VALUE BY GENERATOR BUS#
	770090
Machine MVA Base	249.48
R (pu)	0.0
X'' (pu)	0.893

*pu values based on Machine MVA Base

RESULTS

The results of the short circuit analysis compared the 25SP model with the EGF online and SGF not connected to the stability Scenario 2 dispatch model with both the EGF and SGF in service as described in Section 5.1. The GEN-2026-SR2 POI bus (Buckner County 345 kV - 531501) fault current magnitudes for the comparison cases are provided in Table 6 showing a fault current of 11.901 kA with the EGF and SGF online. The addition of the SGF configuration increased the POI bus fault current by 0.25 kA. Table 7 shows the maximum fault current magnitudes and fault current increases with the SGF project online.

The maximum fault current calculated within five buses of the POI was less than 40 kA for the 25SP model. There were no buses with a maximum three-phase fault current over 40 kA. The maximum contribution to three-phase fault currents due to the addition of the SGF was about 2.85% and 0.249 kA.

Table 6: POI Short-Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
25SP	11.654	11.901	0.25	2.12%

Table 7: 25SP Short-Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	3.58	0.001	0.03%
115	21.25	0.035	0.17%
230	12.81	0.049	0.38%
345	16.348	0.249	2.85%
Max	16.348	0.249	2.85%

DYNAMIC STABILITY ANALYSIS

SPP performed a dynamic stability analysis to identify the impact of the SGF project. The analysis was performed according to SPP's Disturbance Performance Requirements[6]. The project details are described in the *Surplus Interconnection Service Request* section and the dynamic modeling data is provided in Appendix A. The existing base case issues and simulation plots can be found in Appendix C.

METHODOLOGY AND CRITERIA

The dynamic stability analysis was performed using models developed with the requested 66 x FP4200 BESS inverters operating at 2.51 MW (PEPPC_VS0105t) SGF generating facility configuration included in the models. This stability analysis was performed using Siemens PTI's PSS/E® version 34.8.0 software.

Two stability model scenarios were developed using the models from DISIS-2022-001 RESTUDY. The first scenario (Scenario 1) was comprised of the SGF online at 100% of the assumed dispatch (SGF = 165.6 MW) while the EGF generator was offline and disconnected. The second scenario (Scenario 2) was comprised of the SGF at 81.8% of the assumed dispatch (SGF = 130.5 MW) while the EGF generator picked up the remaining EGF GIA capacity (EGF = 35.1 MW). The study scenarios are shown in Table 8.

Table 8: Study Scenarios (Generator Dispatch MW)

SCENARIO	GEN-2010-009 EGF (MW)	GEN-2026-SR2 SGF (MW)	EGF + SGF (MW)
1	0 (Offline)	165.6	165.6
2	35.1	130.5	165.6

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

The GEN-2026-SR2 project details were used to create modified stability models for this impact study based on the DISIS-2022-001 RESTUDY stability study models:

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

The dynamic model data for the GEN-2026-SR2 project is provided in Appendix A. The power flow models and associated dynamic database were initialized (no-fault test) to confirm that there were no errors in the initial conditions of the system and the dynamic data.

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

- The frequency protective relays at buses 599117, 515551, 599119, 599120, 515882, 515883, 515664, 515665, 562685, 515907, 515445, 515439, & 587773 were disabled after observing the generators tripping during initial three phase fault simulations. This frequency tripping issue is a known PSS/E limitation when calculating bus frequency as it relates to non-conventional type devices.
- The voltage protective relays at buses 515969, 515968, 515967, 515986, 515985, 515984, 587953, 587953, 539852, 539853, 539845, 539846, 539847, 539848, 515664, 515665, 588713, 588714, 588715, 588716, 587773, 515907, 760958, 760979, 760937, 761232, & 587773 were disabled to avoid generator tripping due to an instantaneous over voltage spike after fault clearing.
- The fault simulation file acceleration factor was reduced as needed to resolve stability simulation crashes.

During the fault simulations, the study requests and other generation within the cluster group, adjacent powerflow areas, and within five buses away were monitored for compliance with the SPP Disturbance Performance Criteria. The machine rotor angle for synchronous machines within the study areas including 524 (OKGE), 525 (WFEC), 526 (SPS), 531 (MIDW), 534 (SUNC), 536 (WERE), 541 (KCPL), 542 (KACY), 544 (EMDE), 545 (INDN), 546 (SPRM), and 640 (NPPD) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

FAULT DEFINITIONS

SPP developed and simulated fault events as required to study the SGF. The new set of faults was simulated using the modified study models. The fault events included three-phase faults and single-line-to-ground stuck breaker faults. Single-line-to-ground faults are approximated by applying a fault impedance to bring the faulted bus positive sequence voltage to 0.6 pu. The simulated faults are listed and described in Table 9. These contingencies were applied to the modified 25SP and 25WP models.

Table 9: Fault Definitions

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
FLT9001-3PH	P1_2	3 phase fault on the BUCKNER7 (531501) to HOLCOMB7 (531449) 345 kV line CKT 1, near BUCKNER7. a. Apply fault at the BUCKNER7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	P1_2	3 phase fault on the BUCKNER7 (531501) to CIMWD2 7 (531504) 345 kV line CKT 1, near BUCKNER7. a. Apply fault at the BUCKNER7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9003-3PH	P1_2	3 phase fault on the BUCKNER7 (531501) to G21-068-TAP (765911) 345 kV line CKT 1, near BUCKNER7. a. Apply fault at the BUCKNER7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9004-3PH	P1_2	3 phase fault on the BUCKNER7 (531501) to CIMRRN 7 (531502) 345 kV line CKT 1, near BUCKNER7. a. Apply fault at the BUCKNER7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1_3	3 phase fault on the HOLCOMB7 345kV (531449)/ 115 kV (531448)/ 13.8 kV (531450) XFMR CKT 1, near HOLCOMB7 345 kV.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		a. Apply fault at the HOLCOMB7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT9006-3PH	P1_2	3 phase fault on the HOLCOMB7 (531449) to FINNEY 7 (523853) 345 kV line CKT 1, near HOLCOMB7. a. Apply fault at the HOLCOMB7 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.
FLT9007-3PH	P1_2	3 phase fault on the HOLCOMB7 (531449) to SETAB 7 (531465) 345 kV line CKT 1, near HOLCOMB7. a. Apply fault at the HOLCOMB7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	P1_2	3 phase fault on the FINNEY 7 (523853) to LAMAR7 (599950) 345 kV line CKT 1, near FINNEY 7. a. Apply fault at the FINNEY 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9009-3PH	P1_2	3 phase fault on the FINNEY 7 (523853) to CARPENTER 7 (523823) 345 kV line CKT 1, near FINNEY 7. a. Apply fault at the FINNEY 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9010-3PH	P1_2	3 phase fault on the FINNEY 7 (523853) to BUFF_DUNES 7 (523118) 345 kV line CKT 1, near FINNEY 7. a. Apply fault at the FINNEY 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9011-3PH	P1_2	3 phase fault on the HOLCOMB3 (531448) to PLYMELL3 (531393) 115 kV line CKT 1, near HOLCOMB3. a. Apply fault at the HOLCOMB3 115 kV bus.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		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.
FLT9012-3PH	P1_2	3 phase fault on the HOLCOMB3 (531448) to JONES3 (531379) 115 kV line CKT 1, near HOLCOMB3. a. Apply fault at the HOLCOMB3 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9013-3PH	P1_2	3 phase fault on the HOLCOMB3 (531448) to FLETCHR3 (531420) 115 kV line CKT 1, near HOLCOMB3. a. Apply fault at the HOLCOMB3 115 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.
FLT9014-3PH	P1_2	3 phase fault on the HOLCOMB3 (531448) to GRDNCTY3 (531445) 115 kV line CKT 1, near HOLCOMB3. a. Apply fault at the HOLCOMB3 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9015-3PH	P1_2	3 phase fault on the GRDNCTY3 (531445) to S5 GEN 1 (531462) 115 kV line CKT 1, near GRDNCTY3. a. Apply fault at the GRDNCTY3 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9016-3PH	P1_2	3 phase fault on the GRDNCTY3 (531445) to SWNDTAP3 (531476) 115 kV line CKT 1, near GRDNCTY3. a. Apply fault at the GRDNCTY3 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9017-3PH	P1_3	3 phase fault on the GRDNCTY3 115kV (531445)/ 69 kV (531423)/ 13.8 kV (531258) XFMR CKT 1, near GRDNCTY3 115 kV.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		a. Apply fault at the GRDNCTY3 115 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT9018-3PH	P1_2	3 phase fault on the GRDNCTY3 (531445) to KSAVWTP3 (531480) 115 kV line CKT 1, near GRDNCTY3. a. Apply fault at the GRDNCTY3 115 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.
FLT9019-3PH	P1_2	3 phase fault on the GRDNCTY3 (531445) to S2 GEN 1 (531459) 115 kV line CKT 1, near GRDNCTY3. a. Apply fault at the GRDNCTY3 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9020-3PH	P1_3	3 phase fault on the GRDNCTY3 115kV (531445)/ 34.5 kV (531421)/ 13.8 kV (531254) XFMR CKT 1, near GRDNCTY3 115 kV. a. Apply fault at the GRDNCTY3 115 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT9021-3PH	P1_2	3 phase fault on the GRDNCTY3 (531445) to S4 GEN 1 (531461) 115 kV line CKT 1, near GRDNCTY3. a. Apply fault at the GRDNCTY3 115 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.
FLT9022-3PH	P1_3	3 phase fault on the GARDNCY2 69kV (531423)/ 34.5 kV (531422)/ 13.8 kV (531255) XFMR CKT 1, near GARDNCY2 69 kV. a. Apply fault at the GARDNCY2 69 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT9023-3PH	P1_2	3 phase fault on the KSAVWTP3 (531480) to DOBSON 3 (531419) 115 kV line CKT 1, near KSAVWTP3. a. Apply fault at the KSAVWTP3 115 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.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
FLT9024-3PH	P1_2	3 phase fault on the JONES3 (531379) to JAMESON3 (531426) 115 kV line CKT 1, near JONES3. a. Apply fault at the JONES3 115 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.
FLT9025-3PH	P1_2	3 phase fault on the PLYMELL3 (531393) to PIONTAP3 (531392) 115 kV line CKT 1, near PLYMELL3. a. Apply fault at the PLYMELL3 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9026-3PH	P1_2	3 phase fault on the PLYMELL3 (531393) to PIERCVL3 (531408) 115 kV line CKT 1, near PLYMELL3. a. Apply fault at the PLYMELL3 115 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_2	3 phase fault on the G21-068-TAP (765911) to SPERVIL7 (531469) 345 kV line CKT 2, near G21-068-TAP. a. Apply fault at the G21-068-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9032-3PH	P1_2	3 phase fault on the G21-068-TAP (765911) to SPERVIL7 (531469) 345 kV line CKT 1, near G21-068-TAP. a. Apply fault at the G21-068-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9033-3PH	P1_2	3 phase fault on the G21-068-TAP (765911) to GEN-2021-069 (765920) 345 kV line CKT 1, near G21-068-TAP. a. Apply fault at the G21-068-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
FLT9034-3PH	P1_2	3 phase fault on the G21-068-TAP (765911) to GEN-2021-070 (765930) 345 kV line CKT 1, near G21-068-TAP. a. Apply fault at the G21-068-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9035-3PH	P1_2	3 phase fault on the G21-068-TAP (765911) to GEN-2021-068 (765910) 345 kV line CKT 1, near G21-068-TAP. a. Apply fault at the G21-068-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9036-3PH	P1_2	3 phase fault on the SPERVIL7 (531469) to G22-075-TAP (768480) 345 kV line CKT 1, near SPERVIL7. a. Apply fault at the SPERVIL7 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	3 phase fault on the SPERVIL7 345kV (531469)/ 230 kV (539695)/ 13.8 kV (531468) XFMR CKT 1, near SPERVIL7 345 kV. a. Apply fault at the SPERVIL7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT9038-3PH	P1_3	3 phase fault on the SPERVIL7 345kV (531469)/ 115 kV (539759)/ 13.8 kV (539960) XFMR CKT 1, near SPERVIL7 345 kV. a. Apply fault at the SPERVIL7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT9039-3PH	P1_2	3 phase fault on the SPERVIL7 (531469) to IRONWOOD7 (539803) 345 kV line CKT 1, near SPERVIL7. a. Apply fault at the SPERVIL7 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.
FLT9040-3PH	P1_2	3 phase fault on the SPERVIL7 (531469) to G19-030-TAP (763677) 345 kV line CKT 1, near SPERVIL7. a. Apply fault at the SPERVIL7 345 kV bus.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		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_2	3 phase fault on the SPEARVL6 (539695) to SPRVILL-EHVB (539117) 230 kV line CKT Z1, near SPEARVL6. a. Apply fault at the SPEARVL6 230 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	3 phase fault on the SPEARVL6 230kV (539695)/ 115 kV (539694)/ 13.8 kV (539935) XFMR CKT 1, near SPEARVL6 230 kV. a. Apply fault at the SPEARVL6 230 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT9043-3PH	P1_2	3 phase fault on the SPEARVL6 (539695) to G19-055-TAP (763850) 230 kV line CKT 1, near SPEARVL6. a. Apply fault at the SPEARVL6 230 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9044-3PH	P1_2	3 phase fault on the SPRVILL-EHVB (539117) to SPRVILL-EHV2 (539132) 230 kV line CKT 1, near SPRVILL-EHVB. a. Apply fault at the SPRVILL-EHVB 230 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.
FLT9045-3PH	P1_3	3 phase fault on the SPRVILL-EHVB 230kV (539117)/ 34.5 kV (539133)/ 13.8 kV (539134) XFMR CKT 1, near SPRVILL-EHVB 230 kV. a. Apply fault at the SPRVILL-EHVB 230 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT9046-3PH	P1_3	3 phase fault on the SPRVILL-EHVB 230kV (539117)/ 34.5 kV (539752)/ 13.8 kV (539743) XFMR CKT 1, near SPRVILL-EHVB 230 kV. a. Apply fault at the SPRVILL-EHVB 230 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
FLT9047-3PH	P1_3	3 phase fault on the SPRVILL-EHV2 230kV (539132)/ 34.5 kV (539118)/ 13.8 kV (539744) XFMR CKT 1, near SPRVILL-EHV2 230 kV. a. Apply fault at the SPRVILL-EHV2 230 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT9048-3PH	P1_2	3 phase fault on the SVWF3-TX1 (539118) to SVWF3-CLCT1 (539119) 35 kV line CKT 1, near SVWF3-TX1. a. Apply fault at the SVWF3-TX1 35 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_2	3 phase fault on the SVWF2-TX1 (539133) to SVWF2-CLCT1 (539135) 35 kV line CKT 1, near SVWF2-TX1. a. Apply fault at the SVWF2-TX1 35 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.
FLT9050-3PH	P1_2	3 phase fault on the SVWF1-TX1 (539752) to SVWF1-CLCT1 (539115) 35 kV line CKT 1, near SVWF1-TX1. a. Apply fault at the SVWF1-TX1 35 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	3 phase fault on the SPEARVL3 115kV (539694)/ 34.5 kV (539732)/ 13.8 kV (539936) XFMR CKT 1, near SPEARVL3 115 kV. a. Apply fault at the SPEARVL3 115 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT9052-3PH	P1_2	3 phase fault on the SPRVL 3 (539759) to NFTDODG3 (539771) 115 kV line CKT 1, near SPRVL 3. a. Apply fault at the SPRVL 3 115 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.
FLT9053-3PH	P1_2	3 phase fault on the NFTDODG3 (539771) to SPEARVL3 (539694) 115 kV line CKT 1, near NFTDODG3. a. Apply fault at the NFTDODG3 115 kV bus.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		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.
FLT9054-3PH	P1_2	3 phase fault on the IRONWOOD7 (539803) to IRONWOOD WF7 (539815) 345 kV line CKT 1, near IRONWOOD7. a. Apply fault at the IRONWOOD7 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.
FLT9055-3PH	P1_3	3 phase fault on the IRONWOOD WF7 345kV (539815)/ 34.5 kV (539807)/ 13.8 kV (539808) XFMR CKT 1, near IRONWOOD WF7 345 kV. a. Apply fault at the IRONWOOD WF7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR.
FLT9056-3PH	P1_2	3 phase fault on the IRONWOOD 1 (539807) to IRONWOOD 1 4 (539108) 35 kV line CKT 1, near IRONWOOD 1. a. Apply fault at the IRONWOOD 1 35 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.
FLT9057-3PH	P1_2	3 phase fault on the IRONWOOD 1 (539807) to IRONWOOD 1 3 (539107) 35 kV line CKT 1, near IRONWOOD 1. a. Apply fault at the IRONWOOD 1 35 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.
FLT9058-3PH	P1_2	3 phase fault on the IRONWOOD7 (539803) to GEN-2008-124 (579480) 345 kV line CKT 1, near IRONWOOD7. a. Apply fault at the IRONWOOD7 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.
FLT9059-3PH	P1_2	3 phase fault on the IRONWOOD7 (539803) to G16-046-TAP (560080) 345 kV line CKT 1, near IRONWOOD7. a. Apply fault at the IRONWOOD7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT1001-SLG	P4	Apply single-phase fault at BUCKNER7 on the 345kV bus after 16 cycles a. Trip the BUCKNER7 to CIMRRN 7 Transmission Line Ckt 1 b. Trip the BUCKNER7 to CIMWD2 7 Transmission Line Ckt 1
FLT1002-SLG	P4	Apply single-phase fault at BUCKNER7 on the 345kV bus after 16 cycles a. Trip the BUCKNER7 to HOLCOMB7 Transmission Line Ckt 1 b. Trip the BUCKNER7 to G21-068-TAP Transmission Line Ckt 1
FLT1003-SLG	P4	Apply single-phase fault at BUCKNER7 on the 345kV bus after 16 cycles a. Trip the BUCKNER7 to CIMWD2 7 Transmission Line Ckt 1 b. Trip the BUCKNER7 to CIMRRN 7 Transmission Line Ckt 1
FLT1004-SLG	P4	Apply single-phase fault at BUCKNER7 on the 345kV bus after 16 cycles a. Trip the BUCKNER7 to G21-068-TAP Transmission Line Ckt 1 b. Trip the BUCKNER7 to HOLCOMB7 Transmission Line Ckt 1

SCENARIO 1 RESULTS

Table 10 shows the relevant results of the fault events simulated for each of the modified models in Scenario 1. Existing DISIS base case issues are documented separately in Appendix C. The associated stability plots are also provided in Appendix C.

Table 10: Scenario 1 Dynamic Stability Results (EGF = 0 MW, SGF = 165.6 MW)

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	STABLE
FLT9001-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9002-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9003-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	STABLE
FLT9004-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9005-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9006-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9007-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9008-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9009-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9010-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9011-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9012-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9013-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9014-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9015-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9016-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9017-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9018-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9019-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9020-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	STABLE
FLT9021-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9022-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9023-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9024-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9025-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9026-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9031-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9032-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9033-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9034-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9035-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9036-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9037-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9038-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9039-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9040-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9041-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	STABLE
FLT9042-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9043-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9044-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9045-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9046-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9047-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9048-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9049-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9050-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9051-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9052-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9053-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9054-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9055-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9056-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9057-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9058-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	STABLE
FLT9059-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT1001-SLG	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT1002-SLG	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT1003-SLG	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT1004-SLG	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]

The results of the Scenario 1 dynamic stability showed several existing base case issues that were found in both the original DISIS-2022-001 RESTUDY model and the model with GEN-2026-SR2 included. These issues were not attributed to the GEN-2026-SR2 surplus request and detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2026-SR2 surplus request observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

SCENARIO 2 RESULTS

Table 11 shows the relevant results of the fault events simulated for each of the modified models in Scenario 2. Existing DISIS base case issues are documented separately in Appendix C. The associated stability plots are also provided in Appendix C.

Table 11: Scenario 2 Dynamic Stability Results (EGF = 35.1 MW, SGF = 134.5 MW)

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	STABLE
FLT9001-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9002-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9003-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9004-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9005-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9006-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9007-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9008-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9009-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9010-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9011-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9012-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9013-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9014-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9015-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9016-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	STABLE
FLT9017-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9018-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9019-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9020-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9021-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9022-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9023-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9024-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9025-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9026-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9031-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9032-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9033-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9034-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9035-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9036-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9037-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	STABLE
FLT9038-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9039-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9040-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9041-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9042-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9043-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9044-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9045-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9046-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9047-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9048-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9049-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9050-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9051-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9052-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9053-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9054-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	STABLE
FLT9055-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9056-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9057-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9058-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9059-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT1001-SLG	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT1002-SLG	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT1003-SLG	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT1004-SLG	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]

The results of the Scenario 2 dynamic stability showed several existing base case issues that were found in both the original DISIS-2022-001 RESTUDY model and the model with GEN-2026-SR2 included. These issues were not attributed to the GEN-2026-SR2 surplus request and detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2026-SR2 surplus request observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

NECESSARY INTERCONNECTION FACILITIES AND NETWORK UPGRADES

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

INTERCONNECTION FACILITIES

This study did not identify any additional Transmission Owner's Interconnection Facilities required by the addition of the SGF.

NETWORK UPGRADES

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

SURPLUS INTERCONNECTION SERVICE DETERMINATION AND REQUIREMENTS

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

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 SPP. SPP evaluated the impact of the requested Surplus Interconnection Service on the prior study results and determined that the requested Surplus Interconnection Service resulted in similar dynamic stability and short circuit analyses and that the prior study steady-state results are not negatively impacted.

SPP has determined that GEN-2026-SR2 may utilize the requested 165.6 MW of Surplus Interconnection Service being made available by GEN-2010-009.

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 165.6 MW at the POI, which is the total Interconnection Service amount currently granted to the EGF.

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

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