Report on

GEN-2017-074
Modification Request Impact Study

Revision R1   May 12, 2025

Submitted to
Southwest Power Pool

anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
5/12/2025	Aneden Consulting	Initial Report Issued

Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for the GEN-2017-074 project, an active Generation Interconnection Request (GIR) with a Point of Interconnection (POI) at the Pryor Junction 138 kV Substation.

The GEN-2017-074 project interconnects in the American Electric Power (AEP) transmission system with a capacity of 72.5 MW. This Study has been requested to evaluate the modification of the GEN-2017-074 project to change the configuration to 24 x Sungrow SG3600UD solar inverters operating at 3.07 MW for a total assumed dispatch of 73.68 MW. The inverters are rated at 3.6 MVA, thus the generating capability exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount. The injection amount must be limited to 72.5 MW at the POI as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI.

In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformer, auxiliary loads, and generation interconnection line. The previously accepted and modified configurations for GEN-2017-074 are shown in Table ES-1 below.

Table ES-1: GEN-2017-074 Modification Request

Facility	Existing Configuration	Modification Configuration
Point of Interconnection	Pryor Junction 138 kV (510419)	Pryor Junction 138 kV (510419)
Configuration/Capacity	25 x Power Electronics FS3000 operating at 2.9 MW (solar) = 72.5 MW	24 x Sungrow SG3600UD operating at 3.07 MW (solar) = 73.68 MW [dispatch] Units are rated at 3.6 MVA, PPC in place to limit POI to 72.5 MW
Generation Interconnection Line	Length = 0.1 miles R = 0.000070 pu X = 0.000270 pu B = 0.000150 pu Rating MVA = 0 MVA	Length = 0.095 miles R = 0.000059 pu X = 0.000321 pu B = 0.0001254 pu Rating MVA = 217 MVA
Main Substation Transformer[1]	X = 8.997%, R = 0.225%, Winding MVA = 48 MVA, Rating MVA = 80 MVA	X12 = 9.534% R12 = 0.238%, X23 = 3.818% R23 = 0.095%, X13 = 13.338% R13 = 0.333%, Winding MVA = 72 MVA, Winding 1, 2, & 3 Rating MVA = 120 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 25 X = 5.722%, R = 0.572%, Winding MVA = 75 MVA, Rating MVA = 87.5 MVA	Gen 1 Equivalent Qty: 24 X = 5.721%, R = 0.572%, Winding MVA = 86.4 MVA, Rating MVA = 86.4 MVA
Equivalent Collector Line[2]	R = 0.003780 pu X = 0.003900 pu B = 0.006680 pu	R = 0.004203 pu X = 0.004141 pu B = 0.010831 pu
Generator Dynamic Model[3] & Power Factor	25 x Power Electronics FS3000 3.5 MVA (REGCAU1)[3] Leading: 0.99 Lagging: 0.99	24 x Sungrow SG3600UD 3.6 MVA (REGCA1)[3] Leading: 0.85277 Lagging: 0.85277
Auxiliary Load	N/A	0.46 MW + 0.15 MVAr on 34.5 kV Bus

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

SPP determined that steady-state analysis was not required because the modifications to the project were not significant enough to change the previously studied steady-state conclusions. However, SPP determined that the change in manufacturer from Power Electronics to Sungrow required short circuit and dynamic stability analyses.

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

Aneden performed the analyses using the modification request data and the DISIS-2021-001 stability study models:

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

Aneden reviewed Generation Interconnection Requests (GIRs) that shared the same POI, Pryor Junction 138 kV, and updated their models as applicable based on SPP's confirmation of the latest project configurations. The modification under study, GEN-2017-074, is the Existing Generating Facility (EGF) for the GEN-2023-SR26 Surplus Generating Facility (SGF) project. As a result, Aneden included the accepted GEN-2023-SR26 surplus project in the base models and created two stability scenarios to accommodate the status of GEN-2023-SR26.

All analyses were performed using the Siemens PTI PSS/E[1] version 34 software and the results are summarized below.

The results of the reactive power analysis using the 25SP model showed that the GEN-2017-074 project needed a 1.1 MVAr shunt reactor on the 34.5 kV bus of the project substation with the modifications in place, an increase from the 0.7 MVAr found in the DISIS-2017-001-2 study[2]. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during reduced generation conditions. The information gathered from the reactive power analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator (TOP). The applicable reactive power requirements will be further reviewed by the TO and/or TOP.

The short circuit analysis was performed using the 25SP stability model modified for short circuit analysis. The results from the short circuit analysis with the updated topology showed that the maximum GEN-2017-074 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2017-074 POI was 0.51 kA. The maximum three-phase fault current level within 5 buses of the POI was 28.9 kA for the 25SP model.

The dynamic stability analysis was performed using Siemens PTI PSS/E version 34.8.1 software for the two modified study models: 25SP and 25WP, each with two dispatch scenarios to ensure all reliability conditions were studied. 80 fault events were simulated, which included three-phase faults and single-line-to-ground stuck breaker faults.

- Scenario 1: GEN-2017-074 at maximum assumed dispatch, 73.68 MW, and the corresponding SGF, GEN-2023-SR26, disconnected.

[1] Power System Simulator for Engineering
[2] DISIS-2017-001-2 Restudy of Stability and Short Circuit Analysis – June 16, 2022

- Scenario 2: the second scenario dispatch has both the EGF and SGF online using the selected Scenario 2 dispatch from the GEN-2023-SR26 report[3]. As a result, the EGF is dispatched to 42.5 MW and the SGF to 30 MW for a total combination of 72.5 MW.

The results of the dynamic stability analysis showed several existing base case issues that were found in both the original DISIS-2021-001 models (without GEN-2023-SR26) and in the models with the GEN-2017-074 modification (and GEN-2023-SR26) included. These issues were not attributed to the GEN-2017-074 modification request and are detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2017-074 modification 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.

Based on the results of the study, SPP determined that the requested modification is **not a Material Modification**. The requested modification does not have a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date. As the requested modification places the generating capacity of the Interconnection Request at a higher amount than its Interconnection Service, the customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

In accordance with FERC Order No. 827, the generating facility 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.

[3] GEN-2023-SR26 Surplus Service Impact Study – October 25, 2023

1.0 Scope of Study

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for the GEN-2017-074 project. A Modification Request Impact Study is a generation interconnection study performed to evaluate the impacts of modifying the DISIS study assumptions. The determination of the required scope of the study is dependent upon the specific modification requested and how it may impact the results of the DISIS study. Impacting the DISIS results could potentially affect the cost or timing of any Interconnection Request with a later Queue priority date, deeming the requested modification a Material Modification. The criteria sections below include reasoning as to why an analysis was either included or excluded from the scope of study.

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

1.1 Reactive Power Analysis

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

1.2 Short Circuit Analysis & Stability Analysis

To determine whether stability and short circuit analyses are required, SPP evaluates the difference between the stability models, the stability model parameters and, if needed, the equivalent collector system impedance between the existing configuration and the requested modification. Dynamic stability analysis and short circuit analysis would be required if the differences listed above were determined to have a significant impact on the most recently performed DISIS stability analysis. Dynamic stability analysis was performed on two dispatch scenarios, the first where GEN-2017-074 was online at 100% of the assumed dispatch with GEN-2023-SR26 offline and disconnected, and the second, where both the EGF and SGF are online using the selected Scenario 2 dispatch from the GEN-2023-SR26 report[4].

1.3 Steady-State Analysis

Steady-state analysis is performed if SPP deems it necessary based on the nature of the requested change. SPP determined that steady-state analysis was not required because the modifications to the project were not significant enough to change the previously studied steady-state conclusions.

1.4 Study Limitations

The assessments and conclusions provided in this report are based on assumptions and information provided to Aneden by others. While the assumptions and information provided may be appropriate for the purposes of this report, Aneden does not guarantee that those conditions assumed will occur. In addition, Aneden did not independently verify the accuracy or completeness of the information provided. As such, the conclusions and results presented in this report may vary depending on the extent to which actual future conditions differ from the assumptions made or information used herein.

[4] GEN-2023-SR26 Surplus Service Impact Study – October 25, 2023

2.0 Project and Modification Request

The GEN-2017-074 Interconnection Customer requested a modification to its Generation Interconnection Request (GIR) with a Point of Interconnection (POI) at the Pryor Junction 138 kV Substation in the American Electric Power (AEP) transmission system.

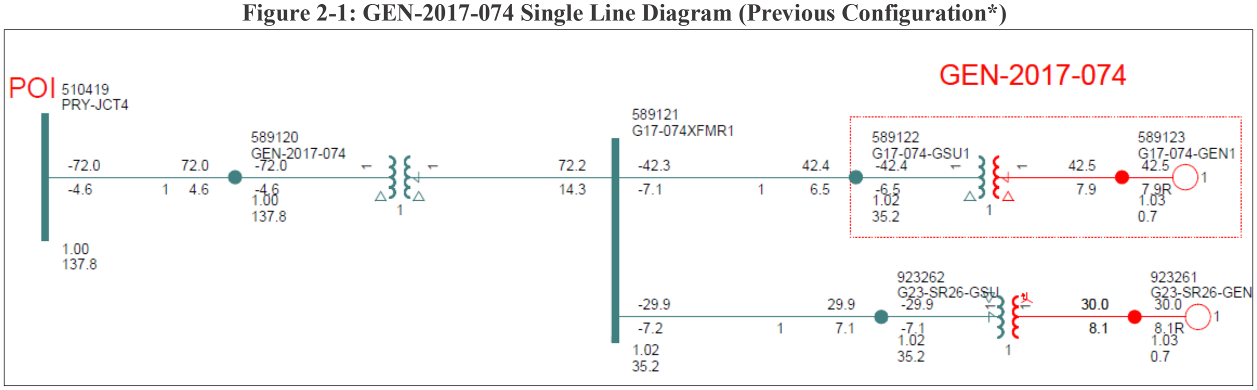
At the time of report posting, the GEN-2017-074 project is an active Interconnection Request with a queue status of "IA FULLY EXECUTED/ON SCHEDULE." GEN-2017-074 is a solar facility with a maximum summer and winter queue capacity of 72.5 MW with Energy Resource Interconnection Service (ERIS).

The GEN-2017-074 project is currently in the DISIS-2017-001 cluster.

Aneden reviewed Generation Interconnection Requests (GIRs) that shared the same POI, Pryor Junction 138 kV, and updated their models as applicable based on SPP's confirmation of the latest project configurations. The modification under study, GEN-2017-074, is the Existing Generating Facility (EGF) for the GEN-2023-SR26 Surplus Generating Facility (SGF) project. As a result, Aneden included the accepted GEN-2023-SR26 surplus project in the base models and created two stability scenarios to accommodate the status of GEN-2023-SR26.

Figure 2-1 shows the power flow model single line diagram for the previously accepted GEN-2017-074 configuration modeled in the DISIS-2021-001 25SP stability model with the GEN-2023-SR26 surplus project included.

Figure 2-1: GEN-2017-074 Single Line Diagram (Previous Configuration*)



*based on the previously accepted configuration with the GEN-2023-SR26 surplus project included

This Study has been requested to evaluate the modification of GEN-2017-074 to change the configuration to 24 x Sungrow SG3600UD solar inverters operating at 3.07 MW for a total assumed dispatch of 73.68 MW. The inverters are rated at 3.6 MVA, thus the generating capability exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount. The injection amount must be limited to 72.5 MW at the POI as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI.

In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformer, auxiliary loads, and generation interconnection line. The previously accepted and modified configurations for GEN-2017-074 are shown in Table ES-1 below.

Figure 2-2 shows the power flow model single line diagram for the GEN-2017-074 modification with the GEN-2023-SR26 surplus project included. The previously accepted and modified configurations for GEN-2017-074 are shown in Table 2-1 below.

Figure 2-2: GEN-2017-074 Single Line Diagram (Modification Configuration)

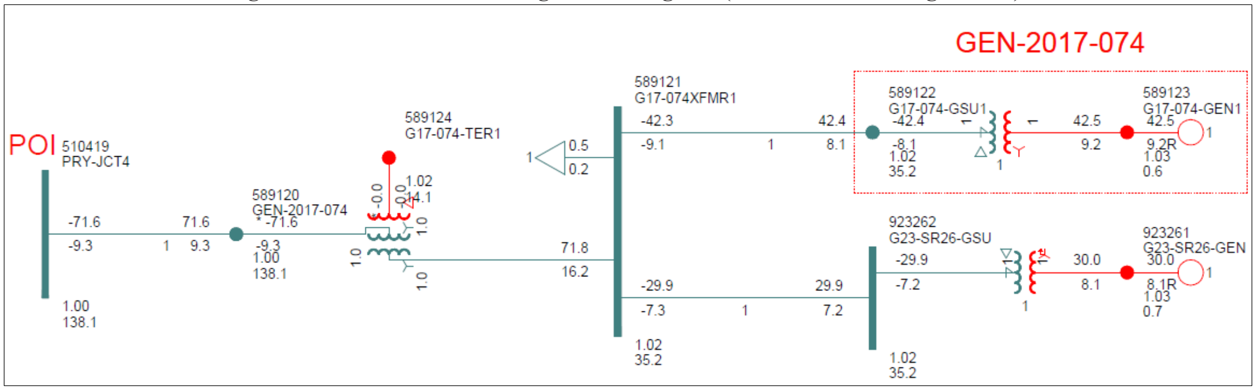


Table 2-1: GEN-2017-074 Modification Request

Facility	Existing Configuration	Modification Configuration
Point of Interconnection	Pryor Junction 138 kV (510419)	Pryor Junction 138 kV (510419)
Configuration/Capacity	25 x Power Electronics FS3000 operating at 2.9 MW (solar) = 72.5 MW	24 x Sungrow SG3600UD operating at 3.07 MW (solar) = 73.68 MW [dispatch] Units are rated at 3.6 MVA, PPC in place to limit POI to 72.5 MW
Generation Interconnection Line	Length = 0.1 miles R = 0.000070 pu X = 0.000270 pu B = 0.000150 pu Rating MVA = 0 MVA	Length = 0.095 miles R = 0.000059 pu X = 0.000321 pu B = 0.0001254 pu Rating MVA = 217 MVA
Main Substation Transformer[1]	X = 8.997%, R = 0.225%, Winding MVA = 48 MVA, Rating MVA = 80 MVA	X12 = 9.534% R12 = 0.238%, X23 = 3.818% R23 = 0.095%, X13 = 13.338% R13 = 0.333%, Winding MVA = 72 MVA, Winding 1, 2, & 3 Rating MVA = 120 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 25 X = 5.722%, R = 0.572%, Winding MVA = 75 MVA, Rating MVA = 87.5 MVA	Gen 1 Equivalent Qty: 24 X = 5.721%, R = 0.572%, Winding MVA = 86.4 MVA, Rating MVA = 86.4 MVA
Equivalent Collector Line[2]	R = 0.003780 pu X = 0.003900 pu B = 0.006680 pu	R = 0.004203 pu X = 0.004141 pu B = 0.010831 pu
Generator Dynamic Model[3] & Power Factor	25 x Power Electronics FS3000 3.5 MVA (REGCAU1)[3] Leading: 0.99 Lagging: 0.99	24 x Sungrow SG3600UD 3.6 MVA (REGCA1)[3] Leading: 0.85277 Lagging: 0.85277
Auxiliary Load	N/A	0.46 MW + 0.15 MVAr on 34.5 kV Bus

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

3.0 Existing vs Modification Comparison

To determine which analyses are required for the Study, the differences between the previously accepted configuration and the requested modification were evaluated. Aneden performed this comparison and the resulting analyses using a set of modified study models developed based on the modification request data and the DISIS-2021-001 stability study models. The analysis was completed using PSS/E version 34 software.

The methodology and results of the comparisons are described below.

3.1 Stability Model Parameters Comparison

SPP determined that short circuit and dynamic stability analyses were required because of the inverter change from Power Electronics to Sungrow inverters. This is because the short circuit contribution and stability responses of the existing configuration and the requested modification's configuration may differ. The generator dynamic model for the modification can be found in Appendix A.

As short circuit and dynamic stability analyses were already deemed required, a stability model parameters comparison was not needed for the determination of the scope of the study.

3.2 Equivalent Impedance Comparison Calculation

As the inverter manufacturer change determined that short circuit and dynamic stability analyses were required, an equivalent impedance comparison was not needed for the determination of the scope of the study.

4.0 Reactive Power Analysis

The reactive power analysis was performed for GEN-2017-074 to determine the capacitive charging effects 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.

4.1 Methodology and Criteria

To determine the shunt reactor size required to compensate for the current charging attributed to the modification request, the shunt size required from the GEN-2023-SR26 surplus study was placed first. Once the shunt size for the SGF was placed, the GEN-2017-074 incremental shunt reactor size was then calculated.

For each of the shunt reactor sizes calculated, all project generators and auxiliary/station service loads were switched offline while other collector system elements remained in-service. A shunt reactor was tested at the project's collection substation 34.5 kV bus to set the MVAr injection at the POI to zero.

The size of the shunt reactor is equivalent to the charging current value at unity voltage and the compensation provided is proportional to the voltage effects on the charging current (i.e., for voltages above unity, reactive compensation is greater than the size of the reactor).

Aneden performed the reactive power analysis using the modification request data based on the 25SP DISIS-2021-001 stability study model.

4.2 Results

The results from the analysis showed that the GEN-2017-074 project needed approximately 1.1 MVAr of compensation at its collector substation to reduce the MVAr injection at the POI to zero with the SGF reactor of 0.1 MVAR in place per the surplus study report[5]. This is an increase from the 0.7 MVAr found in the DISIS-2017-001-2[6] study. The final shunt reactor requirements are shown in Table 4-1. Figure 4-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the updated topology.

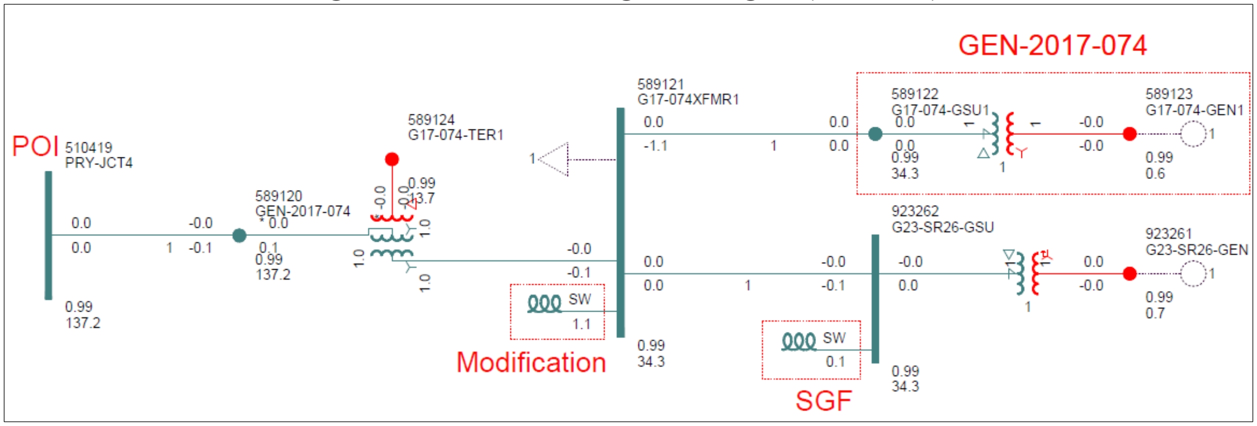
The information gathered from the reactive power analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator (TOP). The applicable reactive power requirements will be further reviewed by the TO and/or TOP.

Table 4-1: Shunt Reactor Size for Reactive Power Analysis

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)
			25SP
GEN-2017-074	510419	PRY-JCT4	1.1

[5] GEN-2023-SR26 Surplus Service Impact Study – October 25, 2023
[6] DISIS-2017-001-2 Restudy of Stability and Short Circuit Analysis – June 16, 2022

Figure 4-1: GEN-2017-074 Single Line Diagram (Shunt Sizes)



5.0 Short Circuit Analysis

Aneden performed a short circuit study using the 25SP model for GEN-2017-074 to determine the maximum fault current requiring interruption by protective equipment for each bus in the relevant subsystem. The detailed results of the short circuit analysis are provided in Appendix B.

5.1 Methodology

The short circuit analysis included applying a 3-phase fault on buses up to 5 levels away from the 138 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels in the transmission system with and without GEN-2017-074 online. The existing SGF, GEN-2023-SR26, was left online for this analysis.

Aneden created a short circuit model using the 25SP DISIS-2021-001 stability study model by adjusting the GEN-2017-074 short circuit parameters consistent with the submitted data. The adjusted parameters used in the short circuit analysis are shown in Table 5-1 below. No other changes were made to the model.

Table 5-1: Short Circuit Model Parameters*

Parameter	Value by Generator Bus#
	589123
Machine MVA Base	86.4
R (pu)	0.0
X'' (pu)	0.53

*pu values based on Machine MVA Base

5.2 Results

The results of the short circuit analysis compared the 25SP model with GEN-2023-SR26 online and the GEN-2017-074 modification not connected to the stability Scenario 2 dispatch model with both the existing SGF and GEN-2017-074 in service as described in Section 6.1. The GEN-2017-074 POI bus (Pryor Junction 138 kV) fault current magnitudes for the comparison cases are provided in Table 5-2 showing a fault current of 9.14 kA with the GEN-2017-074 project online. Table 5-3 shows the maximum fault current magnitudes and fault current increases with the GEN-2017-074 project online.

The maximum fault current calculated within 5 buses of the POI was 28.9 kA for the 25SP model. The maximum GEN-2017-074 contribution to three-phase fault currents was about 5.9% and 0.51 kA.

Table 5-2: POI Short Circuit Comparison Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	kA Change	%Change
25SP	8.63	9.14	0.51	5.9%

Table 5-3: 25SP Short Circuit Comparison Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	13.1	0.21	1.9%
115	17.5	0.19	2.1%
138	9.1	0.51	5.9%
161	28.9	0.09	0.3%
Max	**28.9**	**0.51**	**5.9%**

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the modifications to GEN-2017-074. The analysis was performed according to SPP's Disturbance Performance Requirements[7]. The modification details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix A. The existing base case issues and simulation plots can be found in Appendix C.

6.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested GEN-2017-074 configuration of 24 x Sungrow SG3600UD inverters operating at 3.07 MW (REGCA1). This stability analysis was performed using Siemens PTI's PSS/E version 34.8.1 software.

The modifications requested for the GEN-2017-074 project were used to create modified stability models for this impact study based on the DISIS-2021-001 stability study models:

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

Aneden reviewed GIRs that shared the same POI, Pryor Junction 138 kV, and updated their models as applicable based on SPP's confirmation of the latest project configurations. The modification under study, GEN-2017-074, is the EGF for the GEN-2023-SR26 SGF project. As a result, Aneden included the accepted GEN-2023-SR26 surplus project in the base models and created two stability scenarios to accommodate the status of GEN-2023-SR26.

Two stability model scenarios were developed using these models to ensure all reliability conditions were studied. The first scenario (Scenario 1) was comprised of GEN-2017-074 online at 100% of the assumed dispatch (73.68 MW) while the GEN-2023-SR26 generator was offline and disconnected.

The EGF/SGF dispatch combination for the second scenario (Scenario 2) was taken from the GEN-2023-SR26 report[8]. The study scenarios are shown in Table 6-1.

Table 6-1: Study Scenarios (Generator Dispatch MW)

Scenario	GEN-2017-074 (EGF) (MW)	GEN-2023-SR26 (SGF) (MW)	EGF + SGF (MW)
1	73.68	0 (offline)	73.68
2	42.5	30	72.5

The dynamic model data for the GEN-2017-074 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 modification request:

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

[8] GEN-2023-SR26 Surplus Service Impact Study – October 25, 2023

- The frequency protective relay at bus 763475 was disabled after observing the generator 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 bus 923261 were disabled to avoid generator tripping due to an instantaneous over voltage spike after fault clearing.
- The PSSE dynamic simulation iterations and acceleration factor were adjusted as needed to resolve PSSE dynamic simulation crashes.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2017-074 and other current and prior queued projects in Group 4. In addition, voltages of five (5) buses away from the POI of the GEN-2017-074 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas including 327 (EES-EAI), 330 (AECI), 351 (EES), 356 (AMMO), 502 (CLEC), 515 (SWPA), 520 (AEPW), 523 (GRDA), 524 (OKGE), 525 (WFEC), 526 (SPS), 527 (OMPA), 534 (SUNC), 536 (WERE), 544 (EMDE), and 546 (SPRM) were monitored. The voltages of all 100 kV and above buses within the study area were monitored as well.

6.2 Fault Definitions

Aneden developed fault events as required to study the modification. 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 6-2 below. These contingencies were applied to the modified 25SP and 25WP models.

Table 6-2: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT1000-SB	P4	Stuck Breaker on PRY-JCT4 (510419) 138 kV Bus a. Apply single phase fault at the PRY-JCT4 (510419) 138 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the PRY-JCT4 (510419) 138 kV to BIRDHOL4 (510398) 138 kV line CKT 1. b.2.Trip the BIRDHOL4 (510398) 138 kV to JAY 4 (510421) 138 kV line CKT 1. b.3.Trip the JAY 4 (510421) 138 kV to GROVE 4 (510402) 138 kV line CKT 1. b.4.Trip the PRY-JCT4 (510419) 138 kV / PRY-JCT3 (510407) 115 kV / PRYJT1-1 (510371) 13.8 kV XFMR CKT 1.
FLT1001-SB	P4	Stuck Breaker on PRY-JCT4 (510419) 138 kV Bus a. Apply single phase fault at the PRY-JCT4 (510419) 138 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the PRY-JCT4 (510419) 138 kV / PRY-JCT3 (510407) 115 kV / PRYJT1-1 (510371) 13.8 kV XFMR CKT 1. b.2.Trip the PRY-JCT4 (510419) 138 kV to G20-092-TAP (764160) 138 kV line CKT 1.
FLT1002-SB	P4	Stuck Breaker on PRY-JCT4 (510419) 138 kV Bus a. Apply single phase fault at the PRY-JCT4 (510419) 138 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the PRY-JCT4 (510419) 138 kV to G20-092-TAP (764160) 138 kV line CKT 1. b.2.Trip the PRY-JCT4 (510419) 138 kV / PRY-JCT2 (510400) 69 kV / PRYJT2-1 (510369) 13.8 kV XFMR CKT 1.
FLT1003-SB	P4	Stuck Breaker on PRY-JCT2 (510400) 69 kV Bus a. Apply single phase fault at the PRY-JCT2 (510400) 69 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip bus PRY-JCT2 (510400) 69 kV.
FLT1004-SB	P4	Stuck Breaker on PRYORC12 (512810) 69 kV Bus a. Apply single phase fault at the PRYORC12 (512810) 69 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip bus PRYORC12 (512810) 69 kV.
FLT1005-SB	P4	Stuck Breaker on PRY-JCT3 (510407) 115 kV Bus a. Apply single phase fault at the PRY-JCT3 (510407) 115 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the PRY-JCT3 (510407) 115 kV / PRY-JCT4 (510419) 138 kV / PRYJT1-1 (510371) 13.8 kV XFMR CKT 1. b.2.Trip the PRY-JCT3 (510407) 115 kV to LSTAR--3 (510399) 115 kV line CKT 1. b.3.Trip the LSTAR--3 (510399) 115 kV to L GROVE3 (510423) 115 kV line CKT 1. b.4.Trip the L GROVE3 (510423) 115 kV to KERR GR3 (512634) 115 kV line CKT 1.
FLT1006-SB	P4	Stuck Breaker on G20-092-TAP (764160) 138 kV Bus a. Apply single phase fault at the G20-092-TAP (764160) 138 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip bus G20-092-TAP (764160) 138 kV. Trip generator(s) on the Bus G20-092-GEN1 (764151) 0.7 kV
FLT1007-SB	P4	Stuck Breaker on KERR GR3 (512634) 115 kV Bus a. Apply single phase fault at the KERR GR3 (512634) 115 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the KERR GR3 (512634) 115 kV to L GROVE3 (510423) 115 kV line CKT 1. Trip generator(s) on the Bus KERR_U3 1 (512601) 13.2 kV b.3.Trip the KERR GR3 (512634) 115 kV / KERR BRK4 5 (512771) 161 kV / KERR2 1 (512847) 13.8 kV XFMR CKT 2. Trip generator(s) on the Bus KERR2 1 (512847) 13.8 kV

Table 6-2 continued

Fault ID	Planning Event	Fault Descriptions
FLT1008-SB	P4	Stuck Breaker on KERR GR3 (512634) 115 kV Bus a. Apply single phase fault at the KERR GR3 (512634) 115 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the KERR GR3 (512634) 115 kV / KERR BRK1 5 (512770) 161 kV / KERR1 1 (512846) 13.8 kV XFMR CKT 1. Trip generator(s) on the Bus KERR1 1 (512846) 13.8 kV Trip generator(s) on the Bus KERR_U2 1 (512600) 13.2 kV
FLT1009-SB	P4	Stuck Breaker on KERR GR5 (512635) 161 kV Bus a. Apply single phase fault at the KERR GR5 (512635) 161 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the KERR GR5 (512635) 161 kV to SALNCRK5 (512805) 161 kV line CKT 1. b.2.Trip the KERR GR5 (512635) 161 kV to SALNCRK5 (512805) 161 kV line CKT 2. Trip generator(s) on the Bus SALINA_U1 1 (512608) 13.4 kV Trip generator(s) on the Bus SALINA_U2 1 (512609) 13.4 kV Trip generator(s) on the Bus SALINA_U3 1 (512610) 13.4 kV Trip generator(s) on the Bus SALINA_U4 1 (512611) 13.4 kV Trip generator(s) on the Bus SALINA_U5 1 (512612) 13.4 kV Trip generator(s) on the Bus SALINA_U6 1 (512613) 13.4 kV
FLT1010-SB	P4	Stuck Breaker on KERR GR5 (512635) 161 kV Bus a. Apply single phase fault at the KERR GR5 (512635) 161 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the KERR GR5 (512635) 161 kV to MAID 5 (512648) 161 kV line CKT 1. b.2.Trip the KERR GR5 (512635) 161 kV to MAID 5 (512648) 161 kV line CKT 2.
FLT1011-SB	P4	Stuck Breaker on KERR GR5 (512635) 161 kV Bus a. Apply single phase fault at the KERR GR5 (512635) 161 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the KERR GR5 (512635) 161 kV to 412SUB 5 (512637) 161 kV line CKT 1. b.2.Trip the KERR BRK4 5 (512771) 161 kV / KERR GR3 (512634) 115 kV / KERR2 1 (512847) 13.8 kV XFMR CKT 2. Trip generator(s) on the Bus KERR2 1 (512847) 13.8 kV b.4.Trip the KERR GR5 (512635) 161 kV to PENSA 5 (512654) 161 kV line CKT 1.
FLT1012-SB	P4	Stuck Breaker on KERR GR5 (512635) 161 kV Bus a. Apply single phase fault at the KERR GR5 (512635) 161 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the KERR GR5 (512635) 161 kV to PENSA 5 (512654) 161 kV line CKT 1. b.2.Trip the KERR BRK4 5 (512771) 161 kV / KERR GR3 (512634) 115 kV / KERR2 1 (512847) 13.8 kV XFMR CKT 2. Trip generator(s) on the Bus KERR2 1 (512847) 13.8 kV
FLT1013-SB	P4	Stuck Breaker on KERR GR5 (512635) 161 kV Bus a. Apply single phase fault at the KERR GR5 (512635) 161 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the KERR GR5 (512635) 161 kV to SALNCRK5 (512805) 161 kV line CKT 1. b.2.Trip the KERR BRK4 5 (512771) 161 kV / KERR GR3 (512634) 115 kV / KERR2 1 (512847) 13.8 kV XFMR CKT 2. Trip generator(s) on the Bus KERR2 1 (512847) 13.8 kV b.4.Trip the KERR GR5 (512635) 161 kV to PENSA 5 (512654) 161 kV line CKT 1.
FLT1014-SB	P4	Stuck Breaker on KERR GR5 (512635) 161 kV Bus a. Apply single phase fault at the KERR GR5 (512635) 161 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the KERR GR5 (512635) 161 kV to MAID 5 (512648) 161 kV line CKT 1. b.2.Trip the KERR BRK4 5 (512771) 161 kV / KERR GR3 (512634) 115 kV / KERR2 1 (512847) 13.8 kV XFMR CKT 2. Trip generator(s) on the Bus KERR2 1 (512847) 13.8 kV b.4.Trip the KERR GR5 (512635) 161 kV to PENSA 5 (512654) 161 kV line CKT 1.
FLT9000-3PH	P1	3 Phase fault on PRY-JCT4 (510419) 138 kV to GEN-2017-074 (589120) 138 kV line CKT 1, near PRY-JCT4 (510419) 138 kV. a. Apply fault at the PRY-JCT4 (510419) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. Trip generator(s) on the Bus G17-074-GEN1 (589123) 0.6 kV c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9001-3PH	P1	3 Phase fault on PRY-JCT4 (510419) 138 kV / PRY-JCT2 (510400) 69 kV / PRYJT2-1 (510369) 13.8 kV XFMR CKT 1, near PRY-JCT4 (510419) 138 kV. a. Apply fault at the PRY-JCT4 (510419) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.

Table 6-2 continued

Fault ID	Planning Event	Fault Descriptions
FLT9002-3PH	P1	3 Phase fault on PRY-JCT2 (510400) 69 kV / PRY-JCT4 (510419) 138 kV / PRYJT2-1 (510369) 13.8 kV XFMR CKT 1, near PRY-JCT2 (510400) 69 kV. a. Apply fault at the PRY-JCT2 (510400) 69 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
FLT9003-3PH	P1	3 Phase fault on PRY-JCT2 (510400) 69 kV to ADAIR--2 (510387) 69 kV line CKT 1, near PRY-JCT2 (510400) 69 kV. a. Apply fault at the PRY-JCT2 (510400) 69 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9004-3PH	P1	3 Phase fault on ADAIR--2 (510387) 69 kV to PRY-JCT2 (510400) 69 kV line CKT 1, near ADAIR--2 (510387) 69 kV. a. Apply fault at the ADAIR--2 (510387) 69 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1	3 Phase fault on ADAIR--2 (510387) 69 kV to VINITA-2 (510404) 69 kV line CKT 1, near ADAIR--2 (510387) 69 kV. a. Apply fault at the ADAIR--2 (510387) 69 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9006-3PH	P1	3 Phase fault on VINITA-2 (510404) 69 kV to ADAIR--2 (510387) 69 kV line CKT 1, near VINITA-2 (510404) 69 kV. a. Apply fault at the VINITA-2 (510404) 69 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9007-3PH	P1	3 Phase fault on VINITA-2 (510404) 69 kV to ESH TP 2 (512680) 69 kV line CKT 1, near VINITA-2 (510404) 69 kV. a. Apply fault at the VINITA-2 (510404) 69 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	P1	3 Phase fault on VINITA-2 (510404) 69 kV to VINTAJC2 (510418) 69 kV line CKT 1, near VINITA-2 (510404) 69 kV. a. Apply fault at the VINITA-2 (510404) 69 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9009-3PH	P1	3 Phase fault on PRY-JCT2 (510400) 69 kV to PRYORC12 (512810) 69 kV line CKT 1, near PRY-JCT2 (510400) 69 kV. a. Apply fault at the PRY-JCT2 (510400) 69 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9010-3PH	P1	3 Phase fault on PRYORC12 (512810) 69 kV to PRY-JCT2 (510400) 69 kV line CKT 1, near PRYORC12 (512810) 69 kV. a. Apply fault at the PRYORC12 (512810) 69 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9011-3PH	P1	3 Phase fault on PRYORC12 (512810) 69 kV to PRYORC32 (512622) 69 kV line CKT 1, near PRYORC12 (512810) 69 kV. a. Apply fault at the PRYORC12 (512810) 69 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9012-3PH	P1	3 Phase fault on PRYORC32 (512622) 69 kV to PRYORC12 (512810) 69 kV line CKT 1, near PRYORC32 (512622) 69 kV. a. Apply fault at the PRYORC32 (512622) 69 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.

Table 6-2 continued

Fault ID	Planning Event	Fault Descriptions
FLT9013-3PH	P1	3 Phase fault on PRYORC32 (512622) 69 kV to PRY0RC22 (512639) 69 kV line CKT 1, near PRYORC32 (512622) 69 kV. a. Apply fault at the PRYORC32 (512622) 69 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9014-3PH	P1	3 Phase fault on PRYORC12 (512810) 69 kV to PCP-TAP2 (510408) 69 kV line CKT 1, near PRYORC12 (512810) 69 kV. a. Apply fault at the PRYORC12 (512810) 69 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9015-3PH	P1	3 Phase fault on PCP-TAP2 (510408) 69 kV to PRYORC12 (512810) 69 kV line CKT 1, near PCP-TAP2 (510408) 69 kV. a. Apply fault at the PCP-TAP2 (510408) 69 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9016-3PH	P1	3 Phase fault on PCP-TAP2 (510408) 69 kV to HUNTAP-2 (510416) 69 kV line CKT 1, near PCP-TAP2 (510408) 69 kV. a. Apply fault at the PCP-TAP2 (510408) 69 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9017-3PH	P1	3 Phase fault on PCP-TAP2 (510408) 69 kV to NEOHOME2 (510425) 69 kV line CKT 1, near PCP-TAP2 (510408) 69 kV. a. Apply fault at the PCP-TAP2 (510408) 69 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9018-3PH	P1	3 Phase fault on PRY-JCT4 (510419) 138 kV / PRY-JCT3 (510407) 115 kV / PRYJT1-1 (510371) 13.8 kV XFMR CKT 1, near PRY-JCT4 (510419) 138 kV. a. Apply fault at the PRY-JCT4 (510419) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
FLT9019-3PH	P1	3 Phase fault on PRY-JCT3 (510407) 115 kV / PRY-JCT4 (510419) 138 kV / PRYJT1-1 (510371) 13.8 kV XFMR CKT 1, near PRY-JCT3 (510407) 115 kV. a. Apply fault at the PRY-JCT3 (510407) 115 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
FLT9020-3PH	P1	3 Phase fault on PRY-JCT3 (510407) 115 kV to LSTAR--3 (510399) 115 kV line CKT 1, near PRY-JCT3 (510407) 115 kV. a. Apply fault at the PRY-JCT3 (510407) 115 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9021-3PH	P1	3 Phase fault on KERR GR3 (512634) 115 kV to L GROVE3 (510423) 115 kV line CKT 1, near KERR GR3 (512634) 115 kV. a. Apply fault at the KERR GR3 (512634) 115 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9022-3PH	P1	3 Phase fault on KERR GR3 (512634) 115 kV to KERR_U3 1 (512601) 13.2 kV XFMR CKT 1, near KERR GR3 (512634) 115 kV. a. Apply fault at the KERR GR3 (512634) 115 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer. Trip generator(s) on the Bus KERR_U3 1 (512601) 13.2 kV
FLT9023-3PH	P1	3 Phase fault on KERR GR3 (512634) 115 kV / KERR BRK4 5 (512771) 161 kV / KERR2 1 (512847) 13.8 kV XFMR CKT 2, near KERR GR3 (512634) 115 kV. a. Apply fault at the KERR GR3 (512634) 115 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer. Trip generator(s) on the Bus KERR2 1 (512847) 13.8 kV
FLT9024-3PH	P1	3 Phase fault on KERR BRK4 5 (512771) 161 kV / KERR GR3 (512634) 115 kV / KERR2 1 (512847) 13.8 kV XFMR CKT 2, near KERR BRK4 5 (512771) 161 kV. a. Apply fault at the KERR BRK4 5 (512771) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer. Trip generator(s) on the Bus KERR2 1 (512847) 13.8 kV

Table 6-2 continued

Fault ID	Planning Event	Fault Descriptions
FLT9025-3PH	P1	3 Phase fault on PRY-JCT4 (510419) 138 kV to BIRDHOL4 (510398) 138 kV line CKT 1, near PRY-JCT4 (510419) 138 kV. a. Apply fault at the PRY-JCT4 (510419) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9026-3PH	P1	3 Phase fault on GROVE 4 (510402) 138 kV to JAY 4 (510421) 138 kV line CKT 1, near GROVE 4 (510402) 138 kV. a. Apply fault at the GROVE 4 (510402) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9027-3PH	P1	3 Phase fault on GROVE 4 (510402) 138 kV to COWSKIN 4 (512719) 138 kV line CKT 1, near GROVE 4 (510402) 138 kV. a. Apply fault at the GROVE 4 (510402) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9028-3PH	P1	3 Phase fault on COWSKIN 4 (512719) 138 kV to GROVE 4 (510402) 138 kV line CKT 1, near COWSKIN 4 (512719) 138 kV. a. Apply fault at the COWSKIN 4 (512719) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9029-3PH	P1	3 Phase fault on COWSKIN 4 (512719) 138 kV / COWSKIN2 (512717) 69 kV / COWSKIN1 (512738) 13.8 kV XFMR CKT 1, near COWSKIN 4 (512719) 138 kV. a. Apply fault at the COWSKIN 4 (512719) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
FLT9030-3PH	P1	3 Phase fault on PRY-JCT4 (510419) 138 kV to G20-092-TAP (764160) 138 kV line CKT 1, near PRY-JCT4 (510419) 138 kV. a. Apply fault at the PRY-JCT4 (510419) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9031-3PH	P1	3 Phase fault on G20-092-TAP (764160) 138 kV to PRY-JCT4 (510419) 138 kV line CKT 1, near G20-092-TAP (764160) 138 kV. a. Apply fault at the G20-092-TAP (764160) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9032-3PH	P1	3 Phase fault on G20-092-TAP (764160) 138 kV to MCARBDE4 (510366) 138 kV line CKT 1, near G20-092-TAP (764160) 138 kV. a. Apply fault at the G20-092-TAP (764160) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9033-3PH	P1	3 Phase fault on MCARBDE4 (510366) 138 kV to G20-092-TAP (764160) 138 kV line CKT 1, near MCARBDE4 (510366) 138 kV. a. Apply fault at the MCARBDE4 (510366) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9034-3PH	P1	3 Phase fault on MCARBDE4 (510366) 138 kV to PRY_CRK4 (510431) 138 kV line CKT 1, near MCARBDE4 (510366) 138 kV. a. Apply fault at the MCARBDE4 (510366) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9035-3PH	P1	3 Phase fault on G20-092-TAP (764160) 138 kV to GEN-2020-092 (764150) 138 kV line CKT 1, near G20-092-TAP (764160) 138 kV. a. Apply fault at the G20-092-TAP (764160) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. Trip generator(s) on the Bus G20-092-GEN1 (764151) 0.7 kV c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.

Table 6-2 continued

Fault ID	Planning Event	Fault Descriptions
FLT9036-3PH	P1	3 Phase fault on KERR GR5 (512635) 161 kV to SALNCRK5 (512805) 161 kV line CKT 1, near KERR GR5 (512635) 161 kV. a. Apply fault at the KERR GR5 (512635) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9037-3PH	P1	3 Phase fault on SALNCRK5 (512805) 161 kV to KERR GR5 (512635) 161 kV line CKT 1, near SALNCRK5 (512805) 161 kV. a. Apply fault at the SALNCRK5 (512805) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9038-3PH	P1	3 Phase fault on SALNCRK5 (512805) 161 kV to SALINA 5 (512686) 161 kV line CKT 1, near SALNCRK5 (512805) 161 kV. a. Apply fault at the SALNCRK5 (512805) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. Trip generator(s) on the Bus SALINA_U1 1 (512608) 13.4 kV Trip generator(s) on the Bus SALINA_U2 1 (512609) 13.4 kV Trip generator(s) on the Bus SALINA_U3 1 (512610) 13.4 kV Trip generator(s) on the Bus SALINA_U4 1 (512611) 13.4 kV Trip generator(s) on the Bus SALINA_U5 1 (512612) 13.4 kV Trip generator(s) on the Bus SALINA_U6 1 (512613) 13.4 kV c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9039-3PH	P1	3 Phase fault on KERR GR5 (512635) 161 kV to 412SUB 5 (512637) 161 kV line CKT 1, near KERR GR5 (512635) 161 kV. a. Apply fault at the KERR GR5 (512635) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9040-3PH	P1	3 Phase fault on 412SUB 5 (512637) 161 kV to KERR GR5 (512635) 161 kV line CKT 1, near 412SUB 5 (512637) 161 kV. a. Apply fault at the 412SUB 5 (512637) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9041-3PH	P1	3 Phase fault on 412SUB 5 (512637) 161 kV to KANSATP5 (512714) 161 kV line CKT 1, near 412SUB 5 (512637) 161 kV. a. Apply fault at the 412SUB 5 (512637) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9042-3PH	P1	3 Phase fault on KERR GR5 (512635) 161 kV to PENSA 5 (512654) 161 kV line CKT 1, near KERR GR5 (512635) 161 kV. a. Apply fault at the KERR GR5 (512635) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9043-3PH	P1	3 Phase fault on PENSA 5 (512654) 161 kV to KERR GR5 (512635) 161 kV line CKT 1, near PENSA 5 (512654) 161 kV. a. Apply fault at the PENSA 5 (512654) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9044-3PH	P1	3 Phase fault on PENSA 5 (512654) 161 kV to PENSA_U6 1 (512606) 13.2 kV XFMR CKT 1, near PENSA 5 (512654) 161 kV. a. Apply fault at the PENSA 5 (512654) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer. Trip generator(s) on the Bus PENSA_U6 1 (512606) 13.2 kV
FLT9045-3PH	P1	3 Phase fault on PENSA 5 (512654) 161 kV to DRYGULCH5 (512629) 161 kV line CKT 1, near PENSA 5 (512654) 161 kV. a. Apply fault at the PENSA 5 (512654) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.

Table 6-2 continued

Fault ID	Planning Event	Fault Descriptions
FLT9046-3PH	P1	3 Phase fault on PENSA 5 (512654) 161 kV to KETCHUM5 (512669) 161 kV line CKT 1, near PENSA 5 (512654) 161 kV. a. Apply fault at the PENSA 5 (512654) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9047-3PH	P1	3 Phase fault on PENSA 5 (512654) 161 kV / PENSA 2 (512628) 69 kV / PENSA 1 (512841) 13.8 kV XFMR CKT 1, near PENSA 5 (512654) 161 kV. a. Apply fault at the PENSA 5 (512654) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
FLT9048-3PH	P1	3 Phase fault on KERR GR5 (512635) 161 kV to MAID 5 (512648) 161 kV line CKT 1, near KERR GR5 (512635) 161 kV. a. Apply fault at the KERR GR5 (512635) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9049-3PH	P1	3 Phase fault on MAID 5 (512648) 161 kV to KERR GR5 (512635) 161 kV line CKT 1, near MAID 5 (512648) 161 kV. a. Apply fault at the MAID 5 (512648) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9050-3PH	P1	3 Phase fault on MAID 5 (512648) 161 kV to GERALDGAY5 (512760) 161 kV line CKT 1, near MAID 5 (512648) 161 kV. a. Apply fault at the MAID 5 (512648) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9051-3PH	P1	3 Phase fault on MAID 5 (512648) 161 kV to 5CHOTEAU1 (300069) 161 kV line CKT 1, near MAID 5 (512648) 161 kV. a. Apply fault at the MAID 5 (512648) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9052-3PH	P1	3 Phase fault on MAID 5 (512648) 161 kV to CATSAGR5 (512638) 161 kV line CKT 2, near MAID 5 (512648) 161 kV. a. Apply fault at the MAID 5 (512648) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9053-3PH	P1	3 Phase fault on MAID 5 (512648) 161 kV to GEN-2019-002 (763472) 161 kV line CKT 1, near MAID 5 (512648) 161 kV. a. Apply fault at the MAID 5 (512648) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. Trip generator(s) on the Bus G19-002-GEN1 (763475) 0.7 kV c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9054-3PH	P1	3 Phase fault on MAID 5 (512648) 161 kV to DRYGULCH5 (512629) 161 kV line CKT 1, near MAID 5 (512648) 161 kV. a. Apply fault at the MAID 5 (512648) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9055-3PH	P1	3 Phase fault on MAID 5 (512648) 161 kV to GRDA1 5 (512656) 161 kV line CKT 1, near MAID 5 (512648) 161 kV. a. Apply fault at the MAID 5 (512648) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9056-3PH	P1	3 Phase fault on MAID 5 (512648) 161 kV to LOCSTGVKM 5 (513050) 161 kV line CKT 1, near MAID 5 (512648) 161 kV. a. Apply fault at the MAID 5 (512648) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.

Table 6-2 continued

Fault ID	Planning Event	Fault Descriptions
FLT9057-3PH	P1	3 Phase fault on MAID 5 (512648) 161 kV / MAID 2 (512626) 69 kV / MAITER1 1 (512836) 13.2 kV XFMR CKT 1, near MAID 5 (512648) 161 kV. a. Apply fault at the MAID 5 (512648) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
FLT9058-3PH	P1	3 Phase fault on GROVE 4 (510402) 138 kV / GROVE 5 (510411) 161 kV / GROVE1-1 (510368) 13.8 kV XFMR CKT 1, near GROVE 4 (510402) 138 kV. a. Apply fault at the GROVE 4 (510402) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
FLT9059-3PH	P1	3 Phase fault on GROVE 5 (510411) 161 kV / GROVE 4 (510402) 138 kV / GROVE1-1 (510368) 13.8 kV XFMR CKT 1, near GROVE 5 (510411) 161 kV. a. Apply fault at the GROVE 5 (510411) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
FLT9060-3PH	P1	3 Phase fault on GROVE 5 (510411) 161 kV to NOL435 5 (547496) 161 kV line CKT 1, near GROVE 5 (510411) 161 kV. a. Apply fault at the GROVE 5 (510411) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9061-3PH	P1	3 Phase fault on NOL435 5 (547496) 161 kV to GROVE 5 (510411) 161 kV line CKT 1, near NOL435 5 (547496) 161 kV. a. Apply fault at the NOL435 5 (547496) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9062-3PH	P1	3 Phase fault on NOL435 5 (547496) 161 kV to NEO184 5 (547471) 161 kV line CKT 1, near NOL435 5 (547496) 161 kV. a. Apply fault at the NOL435 5 (547496) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9063-3PH	P1	3 Phase fault on NOL435 5 (547496) 161 kV / NOL435 2 (547610) 69 kV / NOL435 1 (547720) 12.5 kV XFMR CKT 1, near NOL435 5 (547496) 161 kV. a. Apply fault at the NOL435 5 (547496) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
FLT9064-3PH	P1	3 Phase fault on NOL435 5 (547496) 161 kV to DEC392 5 (547484) 161 kV line CKT 1, near NOL435 5 (547496) 161 kV. a. Apply fault at the NOL435 5 (547496) 161 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave Fault on for 7 cycles, then trip the line in (b) and remove fault.

6.3 Scenario 1 Results

Table 6-3 shows the relevant results of the fault events simulated for each of the modified models in Scenario 1. Existing DISIS base case issues are documented separately in Appendix C. The associated stability plots are also provided in Appendix C.

Table 6-3: Scenario 1 Dynamic Stability Results (GEN-2017-074 = 73.68 MW, GEN-2023-SR26 = 0 MW)

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT1000-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-3 continued

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1011-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1012-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1013-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1014-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT9000-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9027-3PH	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-3 continued

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT9028-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9029-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9030-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9031-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9032-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9033-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9034-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9035-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9036-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9037-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9038-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9039-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9040-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9041-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9042-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9043-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9044-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9045-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9046-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9047-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9048-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9049-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9050-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9051-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9052-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9053-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9054-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9055-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9056-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9057-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9058-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9059-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9060-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9061-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9062-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9063-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9064-3PH	Pass	Pass	Stable	Pass	Pass	Stable

The results of the Scenario 1 dynamic stability showed several existing base case issues that were found in both the original DISIS-2021-001 models (without GEN-2023-SR26) and in the models with the GEN-2017-074 modification (and GEN-2023-SR26) included. These issues were not attributed to the GEN-2017-074 modification request and detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2017-074 modification request observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

6.4 Scenario 2 Results

Table 6-4 shows the relevant results of the fault events simulated for each of the modified models in Scenario 2. Existing DISIS base case issues are documented separately in Appendix C. The associated stability plots are also provided in Appendix C.

Table 6-4: Scenario 2 Dynamic Stability Results (GEN-2017-074 = 42.5 MW, GEN-2023-SR26 = 30 MW)

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT1000-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1011-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1012-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1013-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1014-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT9000-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-4 continued

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9027-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9028-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9029-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9030-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9031-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9032-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9033-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9034-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9035-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9036-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9037-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9038-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9039-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9040-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9041-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9042-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9043-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9044-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9045-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9046-3PH	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-4 continued

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT9047-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9048-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9049-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9050-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9051-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9052-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9053-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9054-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9055-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9056-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9057-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9058-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9059-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9060-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9061-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9062-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9063-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9064-3PH	Pass	Pass	Stable	Pass	Pass	Stable

The results of the Scenario 2 dynamic stability showed several existing base case issues that were found in both the original DISIS-2021-001 models (without GEN-2023-SR26) and in the models with the GEN-2017-074 modification (and GEN-2023-SR26) included. These issues were not attributed to the GEN-2017-074 modification request and detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2017-074 modification 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.

7.0 Modified Capacity Exceeds GIA Capacity

Under FERC Order 845, Interconnection Customers are allowed to request Interconnection Service that is lower than the full generating capacity of their planned generating facilities. The Interconnection Customers must install acceptable control and protection devices that prevent the injection above their requested Interconnection Service amount measured at the POI.

As such, Interconnection Customers are allowed to increase the generating capacity of a generating facility without increasing its Interconnection Service amount stated in its GIA. This is allowable as long as they install the proper control and protection devices, and the requested modification is not determined to be a Material Modification.

The modified generating capacity of GEN-2017-074 exceeds the GIA Interconnection Service amount, 72.5 MW, as listed in Appendix A of the GIA.

The customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

8.0 Material Modification Determination

In accordance with Attachment V of SPP's Open Access Transmission Tariff, for modifications other than those specifically permitted by Attachment V, SPP shall evaluate the proposed modifications prior to making them and inform the Interconnection Customer in writing of whether the modifications would constitute a Material Modification. Material Modification shall mean (1) modification to an Interconnection Request in the queue that has a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date; or (2) planned modification to an Existing Generating Facility that is undergoing evaluation for a Generating Facility Modification or Generating Facility Replacement, and has a material adverse impact on the Transmission System with respect to: i) steady-state thermal or voltage limits, ii) dynamic system stability and response, or iii) short-circuit capability limit; compared to the impacts of the Existing Generating Facility prior to the modification or replacement.

8.1 Results

SPP determined the requested modification is not a Material Modification based on the results of this Modification Request Impact Study performed by Aneden. Aneden evaluated the impact of the requested modification on the prior study results. Aneden determined that the requested modification did not negatively impact the prior study dynamic stability and short circuit results, and the modifications to the project were not significant enough to change the previously studied steady-state conclusions.

This determination implies that any network upgrades already required by GEN-2017-074 would not be negatively impacted and that no new upgrades are required due to the requested modification, thus not resulting in a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date.