Report on

GEN-2017-023 Modification Request Impact Study

Revision R1 February 1, 2023

Submitted to
Southwest Power Pool

anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
2/1/2023	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 GEN-2017-023, an active Generation Interconnection Request (GIR) with a Point of Interconnection (POI) at the Hugo Power Plant 138 kV Substation.

The GEN-2017-023 project interconnects in the Western Farmers Electric Cooperative (WFEC) control area with a capacity of 85 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2017-023 to change the inverter configuration to 26 x Sungrow SG3600UD 3.318 MW for a total capacity of 86.268 MW. The inverters are rated at 3.6 MW, and use a Power Plant Controller (PPC) to limit the total power injected into the POI. The generating capacity for GEN-2017-023 (86.268 MW) and the total capability (93.6 MW) exceed its Generator Interconnection Agreement (GIA) Interconnection Service amount, 85 MW, 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. In addition, the modification request included changes to the collection system, generator step-up transformer, generation interconnection line, main substation transformer, and reactive power devices. The existing and modified configurations for GEN-2017-023 are shown in Table ES-2.

Table ES-1: GEN-2017-023 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2017-023	Hugo Power Plant 138 kV (520948)	34 x TMEIC Solar Ware 2.5 MW	85

Table ES-2: GEN-2017-023 Modification Request

Facility	Existing Configuration	Modification Configuration
Point of Interconnection	Hugo Power Plant 138 kV (520948)	Hugo Power Plant 138 kV (520948)
Configuration/Capacity	34 x TMEIC Solar Ware 2.5 MW = 85 MW	26 x Sungrow SG3600UD 3.318 MW = 86.268 MW Units are rated at 3.6 MW, PPC in place to limit POI to 85 MW
Generation Interconnection Line	Length = 1 mile R = 0.001020 pu X = 0.003860 pu B = 0.001000 pu Rating MVA = 0 MVA	Length = 0.6 miles R = 0.000528 pu X = 0.002290 pu B = 0.000681 pu Rating MVA = 137 MVA
Main Substation Transformer[1]	X = 6.995%, R = 0.256%, Winding MVA = 60 MVA, Rating MVA = 100 MVA	X = 8.996%, R = 0.279%, Winding MVA = 80 MVA, Rating MVA = 133.3 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 34 X = 5.722%, R = 0.572%, Winding MVA = 91.8 MVA, Rating MVA = 91.8 MVA	Gen 1 Equivalent Qty: 26 X = 5.706%, R = 0.713%, Winding MVA = 93.6 MVA, Rating MVA = 93.6 MVA
Equivalent Collector Line[2]	R = 0.005860 pu X = 0.005400 pu B = 0.008847 pu	R = 0.006138 pu X = 0.006221 pu B = 0.008392 pu
Generator Dynamic Model[3] & Power Factor	34 x TMEIC Solar Ware 2.7 MVA (REGCAU1)[3] Leading: 0.93 Lagging: 0.93	26 x Sungrow SG3600UD 3.6 MVA (REGCA1)[3] Leading: 0.922 Lagging: 0.922
Reactive Power Devices	N/A	1 x 9 MVAr 34.5 kV Capacitor Bank

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

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.83% compared to the DISIS-2017-002 power flow models (GEN-2017-023 dispatched to 100%). However, SPP determined that the change in inverter manufacturer from TMEIC to Sungrow required short circuit and dynamic stability analyses.

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

Aneden performed the analyses using the modification request data based on the DISIS-2017-002 study models:

1. 2025 Summer Peak (25SP),
2. 2025 Winter Peak (25WP)

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

The results of the charging current compensation analysis using the 25SP and 25WP models showed that the GEN-2017-023 project needed a 0.9 MVAr shunt reactor on the 34.5 kV bus of the project substation with the modifications in place, a decrease from the 1.03 MVAr found in the DISIS-2017-001 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 charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

The 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-2017-023 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2017-023 POI was no greater than 0.35 kA. All three-phase fault current levels within 5 buses of the POI with the GEN-2017-023 generator online were below 41 kA. There is one bus with a maximum three-phase fault current of over 40 kA. This bus is highlighted in Appendix B.

The dynamic stability analysis was performed using Siemens PTI PSS/E version 34.8 software for the two modified study models: 25SP and 25WP. 85 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults.

The results of the dynamic stability analysis showed that there were several existing base case issues found in the original DISIS-2017-002 case and the case with the GEN-2017-023 modification. These issues were not attributed to the GEN-2017-023 modification request and detailed in Appendix D.

There were no damping or voltage recovery violations attributed to the GEN-2017-023 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.

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

The requested modification has been determined by SPP to not be 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.

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 GEN-2017-023. 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 Power Flow Analysis

To determine whether power flow analysis is required, SPP evaluates the difference in the real power output at the POI between the DISIS-2017-002 power flow model configuration and the requested modification. Power flow analysis is performed if the difference in the real power may result in a significant impact on the results of the DISIS power flow analysis.

1.2 Stability Analysis, Short Circuit Analysis

To determine whether stability and short circuit analyses are required, SPP evaluates the difference between 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.

1.3 Charging Current Compensation Analysis

SPP requires that a charging current compensation analysis be performed on the requested modification configuration as it is a non-synchronous resource. The charging current compensation analysis determines the capacitive effect at the POI caused by the project's collector system and transmission line's capacitance. A shunt reactor size is determined in order to offset the capacitive effect and maintain zero (0) MVAr flow at the POI while the project's generators and capacitors are offline.

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.

2.0 Project and Modification Request

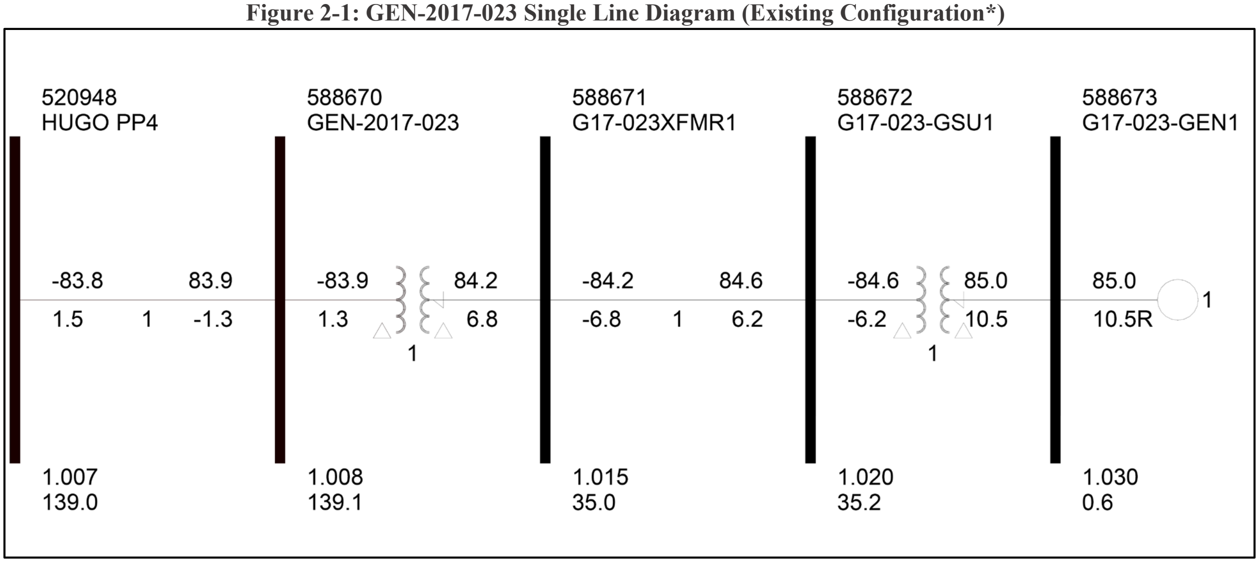
The GEN-2017-023 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a Point of Interconnection (POI) at the Hugo Power Plant 138 kV Substation. At the time of report posting, GEN-2017-023 is an active Interconnection Request with a queue status of "IA FULLY EXECUTED/ON SCHEDULE." GEN-2017-023 is a solar plant with a maximum summer and winter queue capacity of 85 MW with Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS).

The GEN-2017-023 project is currently in the DISIS-2017-001 cluster. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2017-023 configuration using the DISIS-2017-002 stability models. The GEN-2017-023 project interconnects in the Western Farmers Electric Cooperative (WFEC) control area with a capacity of 85 MW as shown in Table 2-1 below.

Table 2-1: GEN-2017-023 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2017-023	Hugo Power Plant 138 kV (520948)	34 x TMEIC Solar Ware 2.5 MW	85

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



*based on the DISIS-2017-002 stability models

This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2017-023 to an inverter configuration of 26 x Sungrow SG3600UD 3.318 MW for a total capacity of 86.268 MW. This generating capacity for GEN-2017-023 (86.268 MW) and the total capability (93.6 MW) exceed its Generator Interconnection Agreement (GIA) Interconnection Service amount, 85 MW, 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.

In addition, the modification request included changes to the collection system, generator step-up transformer, generation interconnection line, main substation transformer, and reactive power devices. Figure 2-2 shows the power flow model single line diagram for the GEN-2017-023 modification. The existing and modified configurations for GEN-2017-023 are shown in Table 2-2.

Figure 2-2: GEN-2017-023 Single Line Diagram (Modification Configuration)

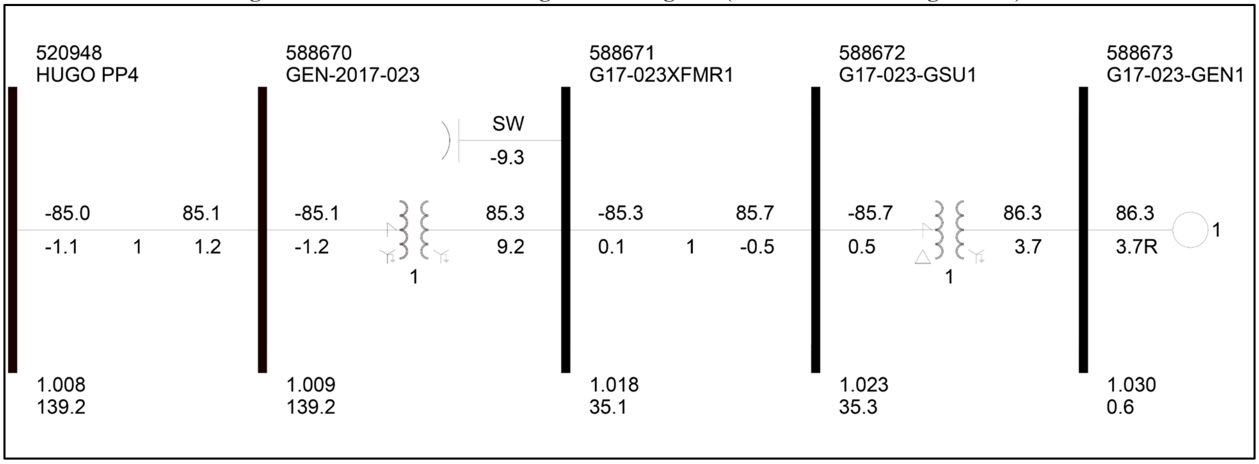


Table 2-2: GEN-2017-023 Modification Request

Facility	Existing Configuration	Modification Configuration
Point of Interconnection	Hugo Power Plant 138 kV (520948)	Hugo Power Plant 138 kV (520948)
Configuration/Capacity	34 x TMEIC Solar Ware 2.5 MW = 85 MW	26 x Sungrow SG3600UD 3.318 MW = 86.268 MW Units are rated at 3.6 MW, PPC in place to limit POI to 85 MW
Generation Interconnection Line	Length = 1 mile R = 0.001020 pu X = 0.003860 pu B = 0.001000 pu Rating MVA = 0 MVA	Length = 0.6 miles R = 0.000528 pu X = 0.002290 pu B = 0.000681 pu Rating MVA = 137 MVA
Main Substation Transformer[1]	X = 6.995%, R = 0.256%, Winding MVA = 60 MVA, Rating MVA = 100 MVA	X = 8.996%, R = 0.279%, Winding MVA = 80 MVA, Rating MVA = 133.3 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 34 X = 5.722%, R = 0.572%, Winding MVA = 91.8 MVA, Rating MVA = 91.8 MVA	Gen 1 Equivalent Qty: 26 X = 5.706%, R = 0.713%, Winding MVA = 93.6 MVA, Rating MVA = 93.6 MVA
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Generator Dynamic Model[3] & Power Factor	34 x TMEIC Solar Ware 2.7 MVA (REGCAU1)[3] Leading: 0.93 Lagging: 0.93	26 x Sungrow SG3600UD 3.6 MVA (REGCA1)[3] Leading: 0.922 Lagging: 0.922
Reactive Power Devices	N/A	1 x 9 MVAr 34.5 kV Capacitor Bank

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

3.0 Existing vs Modification Comparison

To determine which analyses are required for the Study, the differences between the existing 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-2017-002 study models.

The methodology and results of the comparisons are described below. The analysis was completed using PSS/E version 34 software.

3.1 POI Injection Comparison

The real power injection at the POI was determined using PSS/E to compare the DISIS-2017-002 power flow model configuration to the requested modifications with the PPC in place for GEN-2017-023. The percentage change in the POI injection was then evaluated. If the MW percentage difference was determined to be significant, power flow analysis would be performed to assess the impact of the modification request.

SPP determined that power flow analysis was not required due to the insignificant change (increase of 0.83%) in the real power output at the POI between the DISIS-2017-002 power flow model configuration (GEN-2017-023[3] dispatched to 100%) and requested modification shown in Table 3-1.

Table 3-1: GEN-2017-023 POI Injection Comparison

Interconnection Request	Existing POI Injection (MW)	Modification POI Injection (MW)	POI Injection Difference %
GEN-2017-023	84.3	85.0	0.83%

3.2 Stability Model Parameters Comparison

SPP determined that short circuit and dynamic stability analyses were required because of the inverter change from TMEIC to Sungrow. 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 required, a turbine parameters comparison was not needed for the determination of the scope of the study.

3.3 Equivalent Impedance Comparison Calculation

As the inverter 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.

[3] Note that the project was not dispatched to 100% in the starting models due the SPP fuel-based dispatch

4.0 Charging Current Compensation Analysis

The charging current compensation analysis was performed for GEN-2017-023 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

The GEN-2017-023 generators and capacitors were switched out of service while other system elements remained in-service. A shunt reactor was tested at the project's collection substation 34.5 kV bus to set the MVAr flow into the POI to approximately zero. The size of the shunt reactor is equivalent to the charging current value at unity voltage and the compensation provided is proportional to the voltage effects on the charging current (i.e., for voltages above unity, reactive compensation is greater than the size of the reactor).

Aneden performed the charging current compensation analysis using the modification request data based on the DISIS-2017-002 stability study models:

1. 2025 Summer Peak (25SP),
2. 2025 Winter Peak (25WP)

4.2 Results

The results from the analysis showed that the GEN-2017-023 project needed approximately 0.9 MVAr of compensation at its project substation to reduce the POI MVAr to zero. This is a decrease from the 1.03 MVAr found in the DISIS-2017-001 study[4]. Figure 4-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the updated topology. The final shunt reactor requirements for GEN-2017-023 are shown in Table 4-1.

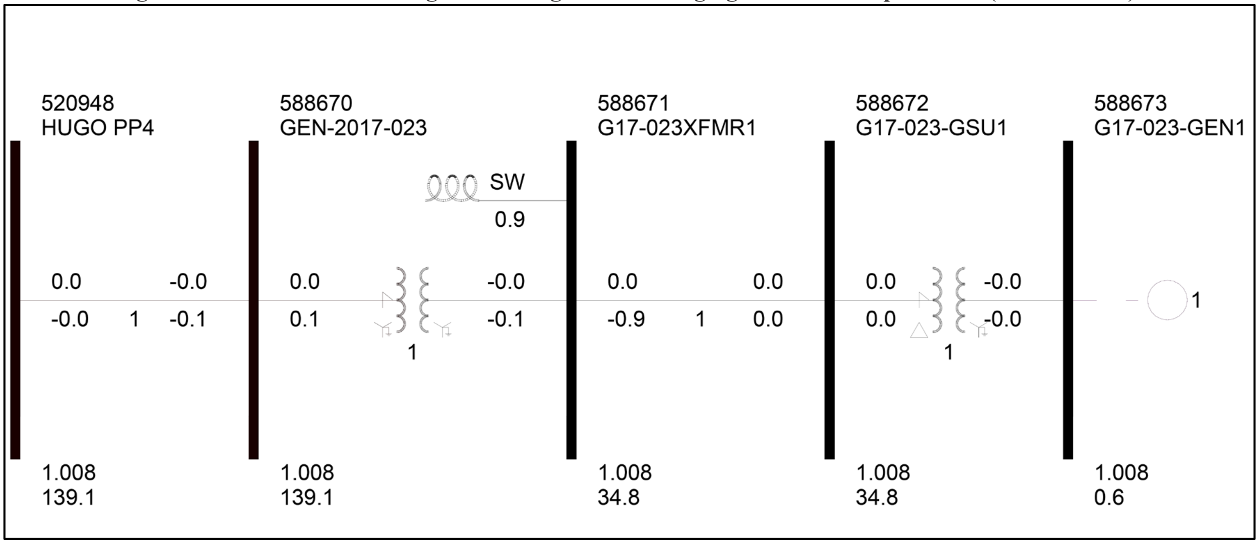
The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission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

Table 4-1: Shunt Reactor Size for Reduced Generation Study (Modification)

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)	
			25SP	25WP
GEN-2017-023	520948	HUGO PP4 138 kV	0.9	0.9

[4] DISIS-2017-001-2 Restudy of Stability and Short Circuit Analysis – June 16, 2022

Figure 4-1: GEN-2017-023 Single Line Diagram w/ Charging Current Compensation (Modification)



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5.0 Short Circuit Analysis

A short circuit study was performed using the 25SP model for GEN-2017-023. The detailed results of the short circuit analysis are provided in Appendix B.

5.1 Methodology

The short circuit analysis included applying a three-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-2017-023 online.

Aneden created a short circuit model using the 25SP DISIS-2017-002 stability study model by adjusting the GEN-2017-023 short circuit parameters consistent with the modification data. The adjusted parameters are shown in Table 5-1 below.

Table 5-1: Short Circuit Model Parameters*

Parameter	Value by Generator Bus#
	588673
Machine MVA Base	93.6
R (pu)	0.0
X'' (pu)	0.9426

*pu values based on Machine MVA Base

5.2 Results

The results of the short circuit analysis for the 25SP model are summarized in Table 5-2 and Table 5-3. The GEN-2017-023 POI bus (HUGO PP4 138 kV - 520948) fault current magnitudes are provided in Table 5-2 showing a maximum fault current of 22.76 kA with the GEN-2017-023 project online. Table 5-3 shows the maximum fault current magnitudes and fault current increases with the GEN-2017-023 project online.

The maximum fault current calculated within 5 buses of the GEN-2017-023 POI (including the POI bus) was less than 41 kA for the 25SP model. There was one bus with a maximum three-phase fault current of over 40 kA. This bus is highlighted in Appendix B. The maximum GEN-2017-023 contribution to three-phase fault current was about 1.6% and 0.35 kA.

Table 5-2: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
25SP	22.41	22.76	0.35	1.6%

Table 5-3: 25SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	7.3	0.01	0.1%
138	40.9	0.35	1.6%
345	28.5	0.06	0.6%
Max	**40.9**	**0.35**	**1.6%**

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the inverter configuration change and other modifications to GEN-2017-023. The analysis was performed according to SPP's Disturbance Performance Requirements shown in Appendix C. 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 D.

6.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested GEN-2017-023 configuration of 26 x Sungrow SG3600UD 3.318 MW (REGCA1). This stability analysis was performed using PTI's PSS/E version 34.8 software.

The modifications requested for the GEN-2017-023 project were used to create modified stability models for this impact study based on the DISIS-2017-002 stability study models:

1. 2025 Summer Peak (25SP),
2. 2025 Winter Peak (25WP)

The modified dynamic model data for the GEN-2017-023 project is provided in Appendix A. The modified 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 GEN-2017-023 (588673) frequency relay 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 following system adjustments were made to address existing base case issues that are not attributed to the modification request:

1. GEN-2017-027 (588713, 588714, 588715, and 588716) voltage protection relays were disabled.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2017-023 and other current and prior queued projects in their cluster group[5]. In addition, voltages of five (5) buses away from the POI of GEN-2017-023 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas including 330 (AECI), 515 (SWPA), 520 (AEPW), 523 (GRDA), 524 (OKGE), 525 (WFEC), 527 (OMPA), and 534 (SUNC) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

6.2 Fault Definitions

Aneden simulated the faults previously simulated for GEN-2017-023 and developed additional fault events as required. The new set of faults were simulated using the modified study models. The fault events included three-phase faults, three-phase faults on prior outage cases, 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 6-1 below. These contingencies were applied to the modified 25SP and 25WP models.

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

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT9001-3PH	P1	3 phase fault on the HUGO PP4 (520948) to SAWYER4 (520411) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	P1	3 phase fault on the HUGO PP4 (520948) to FROGVIL4 (520918) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9003-3PH	P1	3 phase fault on the YNd1 138kV (520948) / 23.4kV (520947) XFMR CKT 1, near HUGO PP4 (520948) 138kV. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted transformer. **Trip the transformer HUGO1 (520947).**
FLT9004-3PH	P1	3 phase fault on the HUGO PP4 (520948) to VALLANT4 (521079) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1	3 phase fault on the HUGO PP4 (520948) to HUGOITC4 (520560) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9006-3PH	P1	3 phase fault on the HUGO PP4 (520948) to VALIANT4 (510918) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9007-3PH	P1	3 phase fault on the HUGO 1 138kV (520560) / 345 kV (521157)/ 13.8 kV (521189) XFMR CKT 1, near HUGOITC4 (520560) 138kV. a. Apply fault at the HUGOITC4 138kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9008-3PH	P1	3 phase fault on the SAWYER4 (520411) to RATTAN 4 (521036) 138kV line CKT 1, near SAWYER4. a. Apply fault at the SAWYER4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9009-3PH	P1	3 phase fault on the FROGVIL4 (520918) to WSBNKTP4 (521098)138kV line CKT 1, near FROGVIL4. a. Apply fault at the FROGVIL4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9010-3PH	P1	3 phase fault on the RATTAN 4 (521036) to DARWIN 4 (520874) 138kV line CKT 1, near RATTAN 4. a. Apply fault at the RATTAN 4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9011-3PH	P1	3 phase fault on the WSBNKTP4 (521098) to UNGER 4 (521077) 138kV line CKT 1, near WSBNKTP4. a. Apply fault at the WSBNKTP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9012-3PH	P1	3 phase fault on the VALLANT4 (521079) to GARVIN4 (520419) 138kV line CKT 1, near VALLANT4. a. Apply fault at the VALLANT4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9013-3PH	P1	3 phase fault on the GARVIN4 (520419) to IDABEL 4 (520953) 138kV line CKT 1, near GARVIN4. a. Apply fault at the GARVIN4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9014-3PH	P1	3 phase fault on the HUGO 7 (521157) to G16-063-TAP (560088) 345 kV line CKT 1, near HUGO 7. a. Apply fault at the HUGO 7 138kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9015-3PH	P1	3 phase fault on the HUGO 7 (521157) to VALIANT7 (510911) 345 kV line CKT 1, near HUGO 7. a. Apply fault at the HUGO 7 138kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9016-3PH	P1	3 phase fault on the VALIANT3 138kV (510918) / 345 kV (510911)/ 13.8 kV (510939) XFMR CKT 1, near VALIANT4 (510918) 138kV. a. Apply fault at the VALIANT4 138kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9017-3PH	P1	3 phase fault on the VALIANT2 138kV (510918) / 69 kV (510910)/ 13.8 kV (510937) XFMR CKT 1, near VALIANT4 (510918) 138kV. a. Apply fault at the VALIANT4 138kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9018-3PH	P1	3 phase fault on the VALIANT4 (510918) to V-WEYCO4 (510866) 138kV line CKT 1, near VALIANT4. a. Apply fault at the VALIANT4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9019-3PH	P1	3 phase fault on the VALIANT4 (510918) to IDABEL-4 (510886) 138kV line CKT 1, near VALIANT4. a. Apply fault at the VALIANT4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9020-3PH	P1	3 phase fault on the VALIANT4 (510918) to HUGO-4 (510901) 138kV line CKT 1, near VALIANT4. a. Apply fault at the VALIANT4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9021-3PH	P1	3 phase fault on the IDABEL-4 (510886) to B.BOWTP4 (510888) 138kV line CKT 1, near IDABEL-4. a. Apply fault at the IDABEL-4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9022-3PH	P1	3 phase fault on the HUGO 138kV (510901) /69 kV (510893)/ 13.8 kV (510859) XFMR CKT 1, near VALIANT4 (510918) 138kV. a. Apply fault at the VALIANT4 138kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9023-3PH	P1	3 phase fault on the G16-063-TAP (560088) to GEN-2017-075 (589130) 345 kV line CKT 1, near G16-063-TAP. a. Apply fault at the G16-063-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip the generator G17-075-GEN1 (589133).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9024-3PH	P1	3 phase fault on the G16-063-TAP (560088) to GEN-2016-063 (587430) 345 kV line CKT 1, near G16-063-TAP. a. Apply fault at the G16-063-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip the generators G16-063-GEN1 (587433), G16-063-GEN2 (587436).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9025-3PH	P1	3 phase fault on the G16-063-TAP (560088) to SUNNYSD7 (515136) 345 kV line CKT 1, near G16-063-TAP. a. Apply fault at the G16-063-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9026-3PH	P1	3 phase fault on the VALIANT7 (510911) to PITTSB-7 (510907) 345 kV line CKT 1, near VALIANT7. a. Apply fault at the VALIANT7 138kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9027-3PH	P1	3 phase fault on the VALIANT7 (510911) to NWTXARK7 (508072) 345 kV line CKT 1, near VALIANT7. a. Apply fault at the VALIANT7 138kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9028-3PH	P1	3 phase fault on the VALIANT7 (510911) to LYDIA 7 (508298) 345 kV line CKT 1, near VALIANT7. a. Apply fault at the VALIANT7 138kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9029-3PH	P1	3 phase fault on the LYDIA 7 (508298) to NWTXARK7 (508072) 345 kV line CKT 1, near LYDIA 7. a. Apply fault at the LYDIA 7 138kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9030-3PH	P1	3 phase fault on the LYDIA 7 (508298) to WELSH 7 (508359) 345 kV line CKT 1, near LYDIA 7. a. Apply fault at the LYDIA 7 138kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9031-3PH	P1	3 phase fault on the SUNNYSD2 345 kV (515136) /138kV (515135)/ 13.8 kV (515405) XFMR CKT 1, near SUNNYSD7 (515136) 345 kV. a. Apply fault at the SUNNYSD7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9032-3PH	P1	3 phase fault on the SUNNYSD2 345 kV (515136) /138kV (515135)/ 13.8 kV (515762) XFMR CKT 1, near SUNNYSD7 (515136) 345 kV. a. Apply fault at the SUNNYSD7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9033-3PH	P1	3 phase fault on the SUNNYSD7 (515136) to TERRYRD7 (511568) 345 kV line CKT 1, near SUNNYSD7. a. Apply fault at the SUNNYSD7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9034-3PH	P1	3 phase fault on the SUNNYSD7 (515136) to JOHNCO 7 (514809) 345 kV line CKT 1, near SUNNYSD7. a. Apply fault at the SUNNYSD7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9035-3PH	P1	3 phase fault on the JOHNCO 7 (514809) to PITTSB-7 (510907) 345 kV line CKT 1, near JOHNCO 7. a. Apply fault at the JOHNCO 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9036-3PH	P1	3 phase fault on the PITTSB-7 (510907) to GEN-2017-156 (761481) 345 kV line CKT 1, near PITTSB-7. a. Apply fault at the PITTSB-7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9037-3PH	P1	3 phase fault on the PITTSB-7 (510907) to SEMINOL7 (515045) 345 kV line CKT 1, near PITTSB-7. a. Apply fault at the PITTSB-7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9038-3PH	P1	3 phase fault on the PITTSB-7 (510907) to C-RIVER7 (515422) 345 kV line CKT 1, near PITTSB-7. a. Apply fault at the PITTSB-7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9039-3PH	P1	3 phase fault on the NWTCARK1 345 kV (508072) /138kV (508071)/ 13.8 kV (508100) XFMR CKT 1, near NWTXARK7 (508072) 345 kV. a. Apply fault at the NWTXARK7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9040-3PH	P1	3 phase fault on the NWTXARK7 (508072) to TURK 7 (507455) 345 kV line CKT 1, near NWTXARK7. a. Apply fault at the NWTXARK7 138kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9041-3PH	P1	3 phase fault on the WELSH 7 (508359) to NWTXARK7 (508072) 345 kV line CKT 1, near WELSH 7. a. Apply fault at the WELSH 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9042-3PH	P1	3 phase fault on the WELSH 7 (508359) to DIANA 7 (508832) 345 kV line CKT 1, near WELSH 7. a. Apply fault at the WELSH 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9043-3PH	P1	3 phase fault on the WELSH 7 (508359) to WILKES 7 (508841) 345 kV line CKT 1, near WELSH 7. a. Apply fault at the WELSH 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9044-3PH	P1	3 phase fault on the WELSH 3 345kV (508359) / 18kV (509406) XFMR CKT 1, near WELSH 7 (508359) 345kV. a. Apply fault at the WELSH 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted transformer. **Trip the transformer HUGO1 (509406).**

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9002-PO1	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to SAWYER4 (520411) 138kV line CKT 1;** 3 phase fault on the HUGO PP4 (520948) to FROGVIL4 (520918) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9003-PO1	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to SAWYER4 (520411) 138kV line CKT 1;** 3 phase fault on the YNd1 138kV (520948) / 23.4kV (520947) XFMR CKT 1, near HUGO PP4 (520948) 138kV. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted transformer. Trip the transformer HUGO1 (520947).
FLT9004-PO1	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to SAWYER4 (520411) 138kV line CKT 1;** 3 phase fault on the HUGO PP4 (520948) to VALLANT4 (521079) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9005-PO1	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to SAWYER4 (520411) 138kV line CKT 1;** 3 phase fault on the HUGO PP4 (520948) to HUGOITC4 (520560) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9006-PO1	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to SAWYER4 (520411) 138kV line CKT 1;** 3 phase fault on the HUGO PP4 (520948) to VALIANT4 (510918) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9001-PO2	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to FROGVIL4 (520918) 138kV line CKT 1;** 3 phase fault on the HUGO PP4 (520948) to SAWYER4 (520411) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9003-PO2	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to FROGVIL4 (520918) 138kV line CKT 1;** 3 phase fault on the YNd1 138kV (520948) / 23.4kV (520947) XFMR CKT 1, near HUGO PP4 (520948) 138kV. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted transformer. Trip the transformer HUGO1 (520947).
FLT9004-PO2	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to FROGVIL4 (520918) 138kV line CKT 1;** 3 phase fault on the HUGO PP4 (520948) to VALLANT4 (521079) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9005-PO2	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to FROGVIL4 (520918) 138kV line CKT 1;** 3 phase fault on the HUGO PP4 (520948) to HUGOITC4 (520560) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9006-PO2	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to FROGVIL4 (520918) 138kV line CKT 1;** 3 phase fault on the HUGO PP4 (520948) to VALIANT4 (510918) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9001-PO3	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to VALLANT4 (521079) 138kV line CKT 1;** 3 phase fault on the HUGO PP4 (520948) to SAWYER4 (520411) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9002-PO3	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to VALLANT4 (521079) 138kV line CKT 1;** 3 phase fault on the HUGO PP4 (520948) to FROGVIL4 (520918) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9003-PO3	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to VALLANT4 (521079) 138kV line CKT 1;** 3 phase fault on the YNd1 138kV (520948) / 23.4kV (520947) XFMR CKT 1, near HUGO PP4 (520948) 138kV. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted transformer. Trip the transformer HUGO1 (520947).
FLT9005-PO3	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to VALLANT4 (521079) 138kV line CKT 1;** 3 phase fault on the HUGO PP4 (520948) to HUGOITC4 (520560) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9006-PO3	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to VALLANT4 (521079) 138kV line CKT 1;** 3 phase fault on the HUGO PP4 (520948) to VALIANT4 (510918) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9001-PO4	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to HUGOITC4 (520560) 138kV line CKT 1;** 3 phase fault on the HUGO PP4 (520948) to SAWYER4 (520411) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9002-PO4	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to HUGOITC4 (520560) 138kV line CKT 1;** 3 phase fault on the HUGO PP4 (520948) to FROGVIL4 (520918) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9003-PO4	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to HUGOITC4 (520560) 138kV line CKT 1;** 3 phase fault on the YNd1 138kV (520948) / 23.4kV (520947) XFMR CKT 1, near HUGO PP4 (520948) 138kV. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted transformer. Trip the transformer HUGO1 (520947).

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9004-PO4	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to HUGOITC4 (520560) 138kV line CKT 1;** 3 phase fault on the HUGO PP4 (520948) to VALLANT4 (521079) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9006-PO4	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to HUGOITC4 (520560) 138kV line CKT 1;** 3 phase fault on the HUGO PP4 (520948) to VALIANT4 (510918) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9001-PO5	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to VALIANT4 (510918) 138kV line CKT 1;** 3 phase fault on the HUGO PP4 (520948) to SAWYER4 (520411) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9002-PO5	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to VALIANT4 (510918) 138kV line CKT 1;** 3 phase fault on the HUGO PP4 (520948) to FROGVIL4 (520918) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9003-PO5	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to VALIANT4 (510918) 138kV line CKT 1;** 3 phase fault on the YNd1 138kV (520948) / 23.4kV (520947) XFMR CKT 1, near HUGO PP4 (520948) 138kV. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted transformer. Trip the transformer HUGO1 (520947).
FLT9004-PO5	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to VALIANT4 (510918) 138kV line CKT 1;** 3 phase fault on the HUGO PP4 (520948) to VALLANT4 (521079) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9005-PO5	P6	**PRIOR OUTAGE of HUGO PP4 (520948) to VALIANT4 (510918) 138kV line CKT 1;** 3 phase fault on the HUGO PP4 (520948) to HUGOITC4 (520560) 138kV line CKT 1, near HUGO PP4. a. Apply fault at the HUGO PP4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT1001-SB	P4	**Stuck Breaker on VALIANT7 (510911) 345kV bus.** a. Apply single-phase fault at VALIANT7 (510911) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT3 138kV (510918) / 345 kV (510911)/ 13.8 kV (510939) XFMR CKT 1. d. Trip the VALIANT3 138kV (510918) / 345 kV (510911)/ 13.8 kV (510938) XFMR CKT 2.
FLT1002-SB	P4	**Stuck Breaker on VALIANT7 (510911) 345kV bus.** a. Apply single-phase fault at VALIANT7 (510911) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT3 138kV (510918) / 345 kV (510911)/ 13.8 kV (510939) XFMR CKT 1. d. Trip the VALIANT7 (510911) to PITTSB-7 (510907) 345 kV line CKT 1.
FLT1003-SB	P4	**Stuck Breaker on VALIANT7 (510911) 345kV bus.** a. Apply single-phase fault at VALIANT7 (510911) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT7 (510911) to LYDIA 7 (508298) 345 kV line CKT 1. d. Trip the VALIANT7 (510911) to PITTSB-7 (510907) 345 kV line CKT 1.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT1004-SB	P4	**Stuck Breaker on VALIANT7 (510911) 345kV bus.** a. Apply single-phase fault at VALIANT7 (510911) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT7 (510911) to LYDIA 7 (508298) 345 kV line CKT 1. d. Trip the VALIANT7 (510911) to HUGO 7 (521157) 345 kV line CKT 1.
FLT1005-SB	P4	**Stuck Breaker on VALIANT7 (510911) 345kV bus.** a. Apply single-phase fault at VALIANT7 (510911) on the 345kV bus. b. Wait 16 cycles and remove fault. d. Trip the VALIANT7 (510911) to HUGO 7 (521157) 345 kV line CKT 1. d. Trip the VALIANT7 (510911) to NWTXARK7 (508072) 345 kV line CKT 1.
FLT1006-SB	P4	**Stuck Breaker on VALIANT7 (510911) 345kV bus.** a. Apply single-phase fault at VALIANT7 (510911) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT3 138kV (510918) / 345 kV (510911)/ 13.8 kV (510938) XFMR CKT 2. d. Trip the VALIANT7 (510911) to NWTXARK7 (508072) 345 kV line CKT 1.
FLT1007-SB	P4	**Stuck Breaker on VALIANT4 (510918) 138kV bus.** a. Apply single-phase fault at VALIANT4 (510918) on the 138kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT4 (510918) to HUGO PP4 (520948) 138kV line CKT 1. d. Trip the VALIANT2 138kV (510918) / 69 kV (510910)/ 13.8 kV (510937) XFMR CKT 1.
FLT1008-SB	P4	**Stuck Breaker on VALIANT4 (510918) 138kV bus.** a. Apply single-phase fault at VALIANT4 (510918) on the 138kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT4 (510918) to HUGO PP4 (520948) 138kV line CKT 1. d. Trip the VALIANT3 138kV (510918) / 345 kV (510911)/ 13.8 kV (510939) XFMR CKT 1.
FLT1009-SB	P4	**Stuck Breaker on VALIANT4 (510918) 138kV bus.** a. Apply single-phase fault at VALIANT4 (510918) on the 138kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT4 (510918) to V-WEYCO4 (510866) 138kV line CKT 1. d. Trip the VALIANT3 138kV (510918) / 345 kV (510911)/ 13.8 kV (510939) XFMR CKT 1.
FLT1010-SB	P4	**Stuck Breaker on VALIANT4 (510918) 138kV bus.** a. Apply single-phase fault at VALIANT4 (510918) on the 138kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT4 (510918) to V-WEYCO4 (510866) 138kV line CKT 1. d. Trip the VALIANT4 (510918) to HUGO-4 (510901) 138kV line CKT 1.
FLT1011-SB	P4	**Stuck Breaker on VALIANT4 (510918) 138kV bus.** a. Apply single-phase fault at VALIANT4 (510918) on the 138kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT3 138kV (510918) / 345 kV (510911)/ 13.8 kV (510938) XFMR CKT 2. d. Trip the VALIANT4 (510918) to HUGO-4 (510901) 138kV line CKT 1. e. Trip the VALIANT4 (510918) to IDABEL-4 (510886) 138kV line CKT 1.
FLT1012-SB	P4	**Stuck Breaker on VALIANT4 (510918) 138kV bus.** a. Apply single-phase fault at VALIANT4 (510918) on the 138kV bus. b. Wait 16 cycles and remove fault. c. Trip the VALIANT3 138kV (510918) / 345 kV (510911)/ 13.8 kV (510938) XFMR CKT 2. d. Trip the VALIANT2 138kV (510918) / 69 kV (510910)/ 13.8 kV (510937) XFMR CKT 1. e. Trip the VALIANT4 (510918) to IDABEL-4 (510886) 138kV line CKT 1.
FLT1013-SB	P4	**Stuck Breaker on at HUGO 7 (521157) at 345kV bus.** a. Apply single-phase fault at HUGO 7 (521157) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the Bus HUGO 7 (521157).
FLT1014-SB	P4	**Stuck Breaker on at HUGO PP4 (520948) at 138kV bus.** a. Apply single-phase fault at HUGO PP4 (520948) on the 138kV bus. b. After 16 cycles, trip the following elements c. Trip the HUGO PP4 (520948) to SAWYER4 (520411) 138kV line CKT 1. d. Trip the HUGO PP4 (520948) to FROGVIL4 (520918) 138kV line CKT 1.
FLT1015-SB	P4	**Stuck Breaker on at HUGO PP4 (520948) at 138kV bus.** a. Apply single-phase fault at HUGO PP4 (520948) on the 138kV bus. b. After 16 cycles, trip the following elements c. Trip the YNd1 138kV (520948) / 23.4kV (520947) XFMR CKT 1 d. Trip the HUGO PP4 (520948) to VALLANT4 (521079) 138kV line CKT 1. **Trip the transformer HUGO1 (520947).**

Table 6-1 Continued

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

6.3 Results

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

Table 6-2: GEN-2017-023 Dynamic Stability Results

Fault ID	25SP			25WP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	25SP			25WP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	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
FLT9002-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO3	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO3	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO3	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO3	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO3	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO4	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO4	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO4	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	25SP			25WP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9004-PO4	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO4	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO5	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO5	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO5	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO5	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO5	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1011-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1012-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1013-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1014-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1015-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1016-SB	Pass	Pass	Stable	Pass	Pass	Stable

The results of the dynamic stability analysis showed that there were several existing base case issues found in the original DISIS-2017-002 case and the case with the GEN-2017-023 modification. These issues were not attributed to the GEN-2017-023 modification request and detailed in Appendix D.

There were no damping or voltage recovery violations attributed to the GEN-2017-023 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.

7.1 Results

The modified generating capacity of GEN-2017-023 (86.268 MW) and the total capability (93.6 MW) exceed the GIA Interconnection Service amount, 85 MW, as listed in Appendix A of the GIA. The GEN-2017-023 inverters are rated at 3.6 MW, and use a Power Plant Controller (PPC) to limit the total power injected into the POI.

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 power flow conclusions.

This determination implies that any network upgrades already required by GEN-2017-023 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.

9.0 Conclusions

The Interconnection Customer for GEN-2017-023 requested a Modification Request Impact Study to assess the impact of the inverter and facility change to 26 x Sungrow SG3600UD 3.318 MW for a total capacity of 86.268 MW. The inverters are rated at 3.6 MW, and use a Power Plant Controller (PPC) to limit the total power injected into the POI. The generating capacity for GEN-2017-023 (86.268 MW) and the total capability (93.6 MW) exceed its Generator Interconnection Agreement (GIA) Interconnection Service amount, 85 MW, 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.

In addition, the modification request included changes to the collection system, generator step-up transformer, generation interconnection line, main substation transformer, and reactive power devices.

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.83% compared to the DISIS-2017-002 power flow models (GEN-2017-023 dispatched to 100%). However, SPP determined that the change in inverter manufacturer from TMEIC to Sungrow required short circuit and dynamic stability analyses.

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

The results of the charging current compensation analysis using the 25SP and 25WP models showed that the GEN-2017-023 project needed a 0.9 MVAr shunt reactor on the 34.5 kV bus of the project substation with the modifications in place, a decrease from the 1.03 MVAr found in the DISIS-2017-001 study[6]. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during reduced generation conditions. The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

The 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-2017-023 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2017-023 POI was no greater than 0.35 kA. All three-phase fault current levels within 5 buses of the POI with the GEN-2017-023 generator online were below 41 kA. There is one bus with a maximum three-phase fault current of over 40 kA. This bus is highlighted in Appendix B.

The dynamic stability analysis was performed using Siemens PTI PSS/E version 34.8 software for the two modified study models: 25SP and 25WP. 85 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults.

The results of the dynamic stability analysis showed that there were several existing base case issues found in the original DISIS-2017-002 case and the case with the GEN-2017-023 modification. These issues were not attributed to the GEN-2017-023 modification request and detailed in Appendix D.

There were no damping or voltage recovery violations attributed to the GEN-2017-023 modification request observed during the simulated faults. Additionally, the project was found to stay connected during the

[6] DISIS-2017-001-2 Restudy of Stability and Short Circuit Analysis – June 16, 2022

contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

The requested modification has been determined by SPP to not be 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.

Appendices

GEN-2017-023

Modification Request Impact Study

Date of Submittal

January 24, 2023

anedenconsulting.com

Appendix A

GEN-2017-023 Generator Dynamic Model

NOTE: Aneden disabled the frequency relay in the GEN-2017-023.dyr file after observing the generator tripping during initial three phase fault simulations.

```
// *************** GEN-2017-023 100% **************
//
// POI on Hugo 138kV
//
// SG3600 3.318 MW X 26 = 86.268 MW
//
// Pmax=86.268 MW | Pgen=86.268 MW
//
// POI limited to 85 MW
//
// 0.908 PF Range

588673 'REGCA1' 1      0
       0.20000E-01   10.000      0.90000      0.50000       1.1000
        1.1000      0.90000      0.30000E-01  -1.0000      0.10000E-01
        0.0000       999.00      -999.00       1.0000      /
588673 'REECA1' 1
        0         0       1       0       0       0
       0.90000         1.1000        0.10000E-01    -0.10000        0.10000
        2.0000         1.0000        -1.0000         1.0000        0.10000E-01
        0.0000         0.0000        0.10000E-01     0.60000       -0.60000
        1.1000        0.90000        0.30000         5.0000        0.50000
        0.0000         0.0000        0.10000E-01      99.000        -99.000
        1.0000         0.0000         1.0000        0.10000E-01     0.50000E-01
        1.0000        0.49000         1.0000        0.50000         1.0000
        1.2000         1.0000        0.50000E-01      1.0000        0.49000
        1.0000        0.50000         1.0000         1.2000         1.0000      /
588673 'REPCA1' 1
        588671        588672        588671    '1 '       1       1       1
       0.50000E-01     0.50000         3.0000         0.0000        0.50000E-01
       0.70000         0.0000         0.0000         0.0000        0.50000E-01
      -0.50000E-01      0.0000         0.0000         0.60000       -0.60000
       0.50000         0.25000        0.25000       -0.60000E-03    0.60000E-03
        999.00        -999.00         1.0000         0.0000        0.50000
        20.000         20.000      /
58867301   'VTGTPAT'   588673  588673  '1 '    0.50000      999.00      3.0000      0.0000     /
58867302   'VTGTPAT'   588673  588673  '1 '    0.88000      999.00      1.1000      0.0000     /
58867303   'VTGTPAT'   588673  588673  '1 '     0.0000      1.1000      2.0000      0.0000     /
58867304   'VTGTPAT'   588673  588673  '1 '     0.0000      1.2000      0.16000     0.0000     /
58867305   'FRQTPAT'   588673  588673  '1 '     58.500      999.00      300.00      0.0000     /
58867306   'FRQTPAT'   588673  588673  '1 '     56.500      999.00      0.16000     0.0000     /
58867307   'FRQTPAT'   588673  588673  '1 '     0.0000      62.000      0.16000     0.0000     /
58867308   'FRQTPAT'   588673  588673  '1 '     0.0000      61.200      300.00      0.0000     /
```

Appendix B

Short Circuit Results

Table B-1: 25SP Short Circuit Results

BUS NUMBER	BUS NAME	Voltage (kV)	AREA	ZONE	3 Phase Fault Current (kA)		Difference (ON - OFF)		Distance from GEN POI Bus	Greater Than 40 kA
					GenON	GenOFF	Change	%	520948	
515044	SEMINOL4	138	524	568	40.885	40.882	0.003	0.01%	5	TRUE
520948	HUGO PP4	138	525	579	22.764	22.413	0.351	1.57%	0	FALSE
510918	VALIANT4	138	520	548	14.987	14.938	0.049	0.33%	1	FALSE
520411	SAWYER4	138	525	579	10.531	10.465	0.066	0.63%	1	FALSE
520560	HUGOITC4	138	525	579	22.434	22.119	0.315	1.42%	1	FALSE
520918	FROGVIL4	138	525	579	10.659	10.591	0.068	0.64%	1	FALSE
521079	VALLANT4	138	525	579	8.595	8.556	0.039	0.46%	1	FALSE
588670	GEN-2017-023	138	525	577	20.288	N/A	N/A	N/A	1	FALSE
510866	V-WEYCO4	138	520	548	9.533	9.513	0.020	0.21%	2	FALSE
510886	IDABEL-4	138	520	548	6.789	6.782	0.007	0.10%	2	FALSE
510901	HUGO---4	138	520	548	3.495	3.492	0.003	0.09%	2	FALSE
510910	VALIANT2	69	520	548	7.343	7.337	0.006	0.08%	2	FALSE
510911	VALIANT7	345	520	548	13.462	13.410	0.052	0.39%	2	FALSE
520419	GARVIN4	138	525	579	5.954	5.942	0.012	0.20%	2	FALSE
521036	RATTAN 4	138	525	579	6.824	6.800	0.024	0.35%	2	FALSE
521098	WSBNKTP4	138	525	579	6.574	6.553	0.021	0.32%	2	FALSE
521157	HUGO 7	345	525	579	11.359	11.297	0.062	0.55%	2	FALSE
508072	NWTXARK7	345	520	528	13.146	13.133	0.013	0.10%	3	FALSE
508298	LYDIA 7	345	520	529	12.680	12.665	0.015	0.12%	3	FALSE
510870	WCITYTP2	69	520	548	6.385	6.380	0.005	0.08%	3	FALSE
510876	KIPUMPT2	69	520	548	4.872	4.869	0.003	0.06%	3	FALSE
510888	B.BOWTP4	138	520	548	7.137	7.130	0.007	0.10%	3	FALSE
510893	HUGO---2	69	520	548	5.086	5.083	0.003	0.06%	3	FALSE
510907	PITTSB-7	345	520	548	14.736	14.727	0.009	0.06%	3	FALSE
520497	WSTBANK4	138	525	579	5.112	5.100	0.012	0.24%	3	FALSE
520874	DARWIN 4	138	525	579	4.748	4.741	0.007	0.15%	3	FALSE
520953	IDABEL 4	138	525	579	6.027	6.018	0.009	0.15%	3	FALSE
521077	UNGER 4	138	525	579	4.936	4.927	0.009	0.18%	3	FALSE
560088	G16-063-TAP	345	524	567	8.074	8.065	0.009	0.11%	3	FALSE
507455	TURK 7	345	520	526	8.853	8.849	0.004	0.05%	4	FALSE
508071	NWTXARK4	138	520	528	24.566	24.550	0.016	0.07%	4	FALSE
508359	WELSH 7	345	520	529	20.942	20.933	0.009	0.04%	4	FALSE
510864	B.BOW 4	138	520	548	6.138	6.133	0.005	0.08%	4	FALSE
510868	GA PAC 2	69	520	548	2.487	2.487	0.000	0.00%	4	FALSE
510869	W CITY 2	69	520	548	3.854	3.853	0.001	0.03%	4	FALSE
510875	KI PMPN2	69	520	548	3.450	3.449	0.001	0.03%	4	FALSE
510890	CRAIGJT4	138	520	548	8.615	8.606	0.009	0.10%	4	FALSE
510894	VALYTIM2	69	520	548	2.699	2.699	0.000	0.00%	4	FALSE
510917	FTOWSON2	69	520	548	3.785	3.784	0.001	0.03%	4	FALSE
510920	SAWYER 2	69	520	548	3.882	3.881	0.001	0.03%	4	FALSE
510925	KIOWA 7	345	520	548	14.456	14.447	0.009	0.06%	4	FALSE
514809	JOHNCO 7	345	524	567	11.377	11.372	0.005	0.04%	4	FALSE
515045	SEMINOL7	345	524	568	28.534	28.531	0.003	0.01%	4	FALSE
515136	SUNNYSD7	345	524	567	12.058	12.052	0.006	0.05%	4	FALSE
515422	C-RIVER7	345	524	565	10.171	10.169	0.002	0.02%	4	FALSE
520466	HAWORTH4	138	525	579	4.117	4.112	0.005	0.12%	4	FALSE
520826	BENNGTN4	138	525	593	4.629	4.624	0.005	0.11%	4	FALSE
520946	HOLYCRK4	138	525	579	6.270	6.261	0.009	0.14%	4	FALSE
520968	LANE 4	138	525	593	4.945	4.941	0.004	0.08%	4	FALSE
587430	GEN-2016-063	345	524	567	7.968	7.960	0.008	0.10%	4	FALSE
589130	GEN-2017-075	345	524	567	8.063	8.054	0.009	0.11%	4	FALSE
761481	GEN-2017-156	345	520	1	3.576	3.576	0.000	0.00%	4	FALSE
5917	SPPMAINBUS	345	520	520	20.942	20.933	0.009	0.04%	5	FALSE
504124	ASHDWN_W 4	138	520	544	9.787	9.784	0.003	0.03%	5	FALSE
505614	BRKN BW4	138	515	523	7.331	7.325	0.006	0.08%	5	FALSE
507419	DEQUEEN4	138	520	526	4.113	4.111	0.002	0.05%	5	FALSE
507431	PATTERS4	138	520	526	12.942	12.937	0.005	0.04%	5	FALSE
507454	TURK 4	138	520	526	24.186	24.179	0.007	0.03%	5	FALSE
507461	GORDON TAP 4	138	520	544	2.588	2.588	0.000	0.00%	5	FALSE
508049	NASH 4	138	520	528	19.148	19.139	0.009	0.05%	5	FALSE
508070	NWT-BNT4	138	520	528	23.582	23.568	0.014	0.06%	5	FALSE
508080	SUGARHL4	138	520	528	11.875	11.872	0.003	0.03%	5	FALSE
508832	DIANA 7	345	520	531	18.784	18.780	0.004	0.02%	5	FALSE
508841	WILKES 7	345	520	531	15.247	15.245	0.002	0.01%	5	FALSE
510867	KI PMPS2	69	520	548	3.083	3.082	0.001	0.03%	5	FALSE
510887	ATOKA--4	138	520	548	5.833	5.830	0.003	0.05%	5	FALSE
510915	ANTLTAP2	69	520	548	2.491	2.491	0.000	0.00%	5	FALSE
510946	C-RIVER4	138	520	548	13.029	13.027	0.002	0.02%	5	FALSE
511568	TERRYRD7	345	520	549	10.408	10.407	0.001	0.01%	5	FALSE
514808	JOHNCO 4	138	524	567	15.804	15.800	0.004	0.03%	5	FALSE
514908	ARCADIA7	345	524	569	28.281	28.281	0.000	0.00%	5	FALSE
514934	DRAPER 7	345	524	569	25.954	25.953	0.001	0.00%	5	FALSE
515135	SUNNYSD4	138	524	567	20.393	20.388	0.005	0.02%	5	FALSE
515224	MUSKOGE7	345	524	565	27.399	27.399	0.000	0.00%	5	FALSE
516006	DMNDSPG7	345	524	567	8.005	8.003	0.002	0.02%	5	FALSE
520834	BROKNBW4	138	525	579	6.778	6.770	0.008	0.12%	5	FALSE
520884	DURANTP4	138	525	593	5.427	5.423	0.004	0.07%	5	FALSE
521004	MTRIVER4	138	525	579	8.271	8.262	0.009	0.11%	5	FALSE
521115	BENNSUB4	138	525	593	4.360	4.356	0.004	0.09%	5	FALSE
588839	FIREWHL-TAP	345	524	565	11.233	11.232	0.001	0.01%	5	FALSE
760830	GEN-2017-149	345	524	1	4.158	4.157	0.001	0.02%	5	FALSE

Appendix C

SPP Disturbance Performance Requirements

Southwest Power Pool Disturbance Performance Requirements

Revision 3.0

July 21, 2016

Revision History

Version Number	Author	Change Description	Comments
1.0 (1/13/2013)	Transient Stability Task Force	First draft	TWG approval of Rotor Angle Damping
1.1 (7/31/2013)	Transmission Working Group	Approval of entire document	Approval of both Rotor Angle Damping and Transient Voltage requirements and addressed items regarding SPPR figure.
2.0 (12/15/2015)	Transmission Working Group	Revision to Transient Voltage Requirements	Addition of 2.5 seconds delay of looking at voltage being above 0.7 p.u.
3.0 (7/21/2016)	Dynamic Load Task Force	Revision to Rotor Angle Damping Requirements	Edited verbiage to clarify rotor angle requirements.

Southwest Power Pool
Disturbance Performance Requirements

OVERVIEW

These Disturbance Performance Requirements ("Requirements") shall be applicable to the Bulk Electric System within the Southwest Power Pool Planning Area. Utilization of these Requirements applies to all registered entities within the Southwest Power Pool Planning Area. These Requirements shall not be applicable to facilities that are not part of Bulk Electric System. More stringent Requirements are at the sole discretion of each Transmission Planner.

Transient and dynamic stability assessments are generally performed to assure adequate avoidance of loss of generator synchronism and prevention of system voltage collapse within the first 20 seconds after a system disturbance. These Requirements provide a basis for evaluating the system response during the initial transient period following a disturbance on the Bulk Electric System by establishing minimum requirements for machine rotor angle damping and transient voltage recovery.

ROTOR ANGLE DAMPING REQUIREMENT

Machine Rotor Angles shall exhibit well damped angular oscillations following a disturbance on the Bulk Electric System for all NERC TPL-001-4 P1 through P7 events.

Machines with rotor angle deviations greater than or equal to 16 degrees (measured as absolute maximum peak to absolute minimum peak) shall be evaluated against SPPR1 or SPPR5 requirements below. Machines with rotor angle deviations less than 16 degrees which do not exhibit convergence shall be evaluated on an individual basis. Rotor angle deviations will be calculated relative to the system swing machine.

Well damped angular oscillations shall meet one of the following two requirements when calculated directly from the rotor angle:

1. Successive Positive Peak Ratio One (SPPR1) must be less than or equal to 0.95 where SPPR1 is calculated as follows:

$$\text{SPPR1} = \frac{\text{Peak Rotor Angle of } 2^{nd} \text{ Positive Peak minus Minimum Value}}{\text{Peak Rotor Angle of } 1^{st} \text{ Positive Peak minus Minimum Value}} \leq 0.95$$

   -or- Damping Factor % = (1 – SPPR1) x 100% $\geq$ 5%

   The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

   Damping Ratio $\geq$ 0.0081633

2. Successive Positive Peak Ratio Five (SPPR5) must be less than or equal to 0.774 where SPPR5 is calculated as follows:

$$\text{SPPR5} = \frac{\text{Peak Rotor Angle of } 6^{th} \text{ Positive Peak minus Minimum Value}}{\text{Peak Rotor Angle of } 1^{st} \text{ Positive Peak minus Minimum Value}} \leq 0.774$$

   -or- Damping Factor % = (1 – SPPR5) x 100% $\geq$ 22.6%

   The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

   Damping Ratio $\geq$ 0.0081633

Qualitatively, these Requirements are shown in Figure 1 & 2 below.

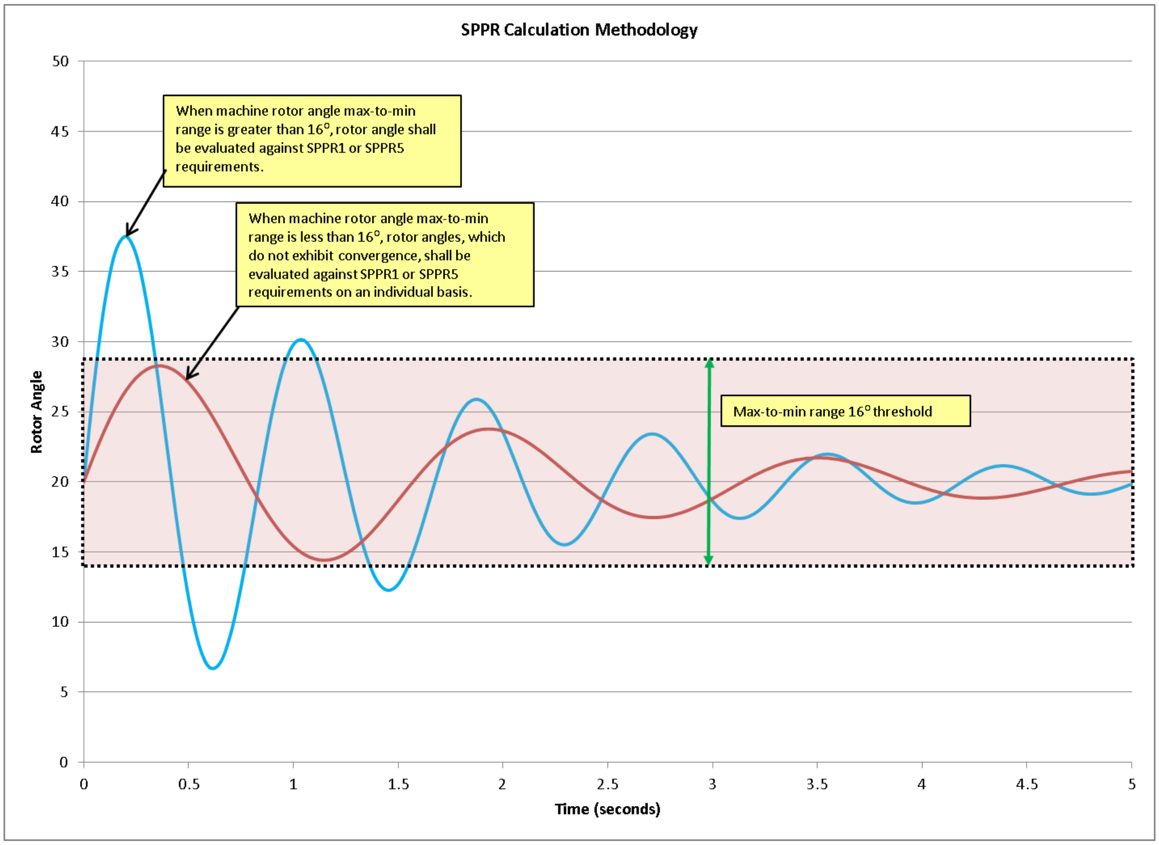


Figure 1. Applicability of 16 Degree Threshold

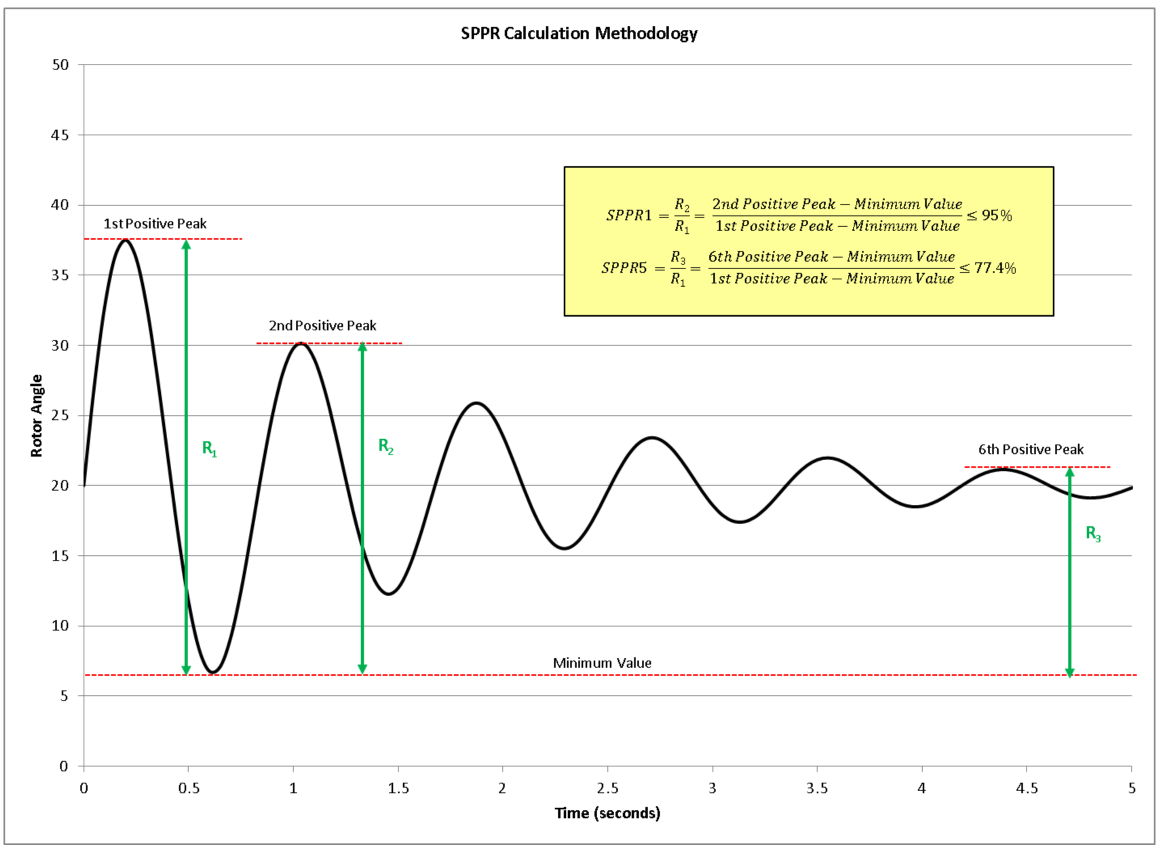


Figure 2. SPPR1 and SPPR5 Calculations

TRANSIENT VOLTAGE RECOVERY REQUIREMENT

Bus voltages on the Bulk Electric System shall recover above 0.70 per unit, 2.5 seconds after the fault is cleared. Bus voltages shall not swing above 1.20 per unit after the fault is cleared, unless affected transmission system elements are designed to handle the rise above 1.2 per unit.

Qualitatively, this Requirement is shown in Figure 3 below.

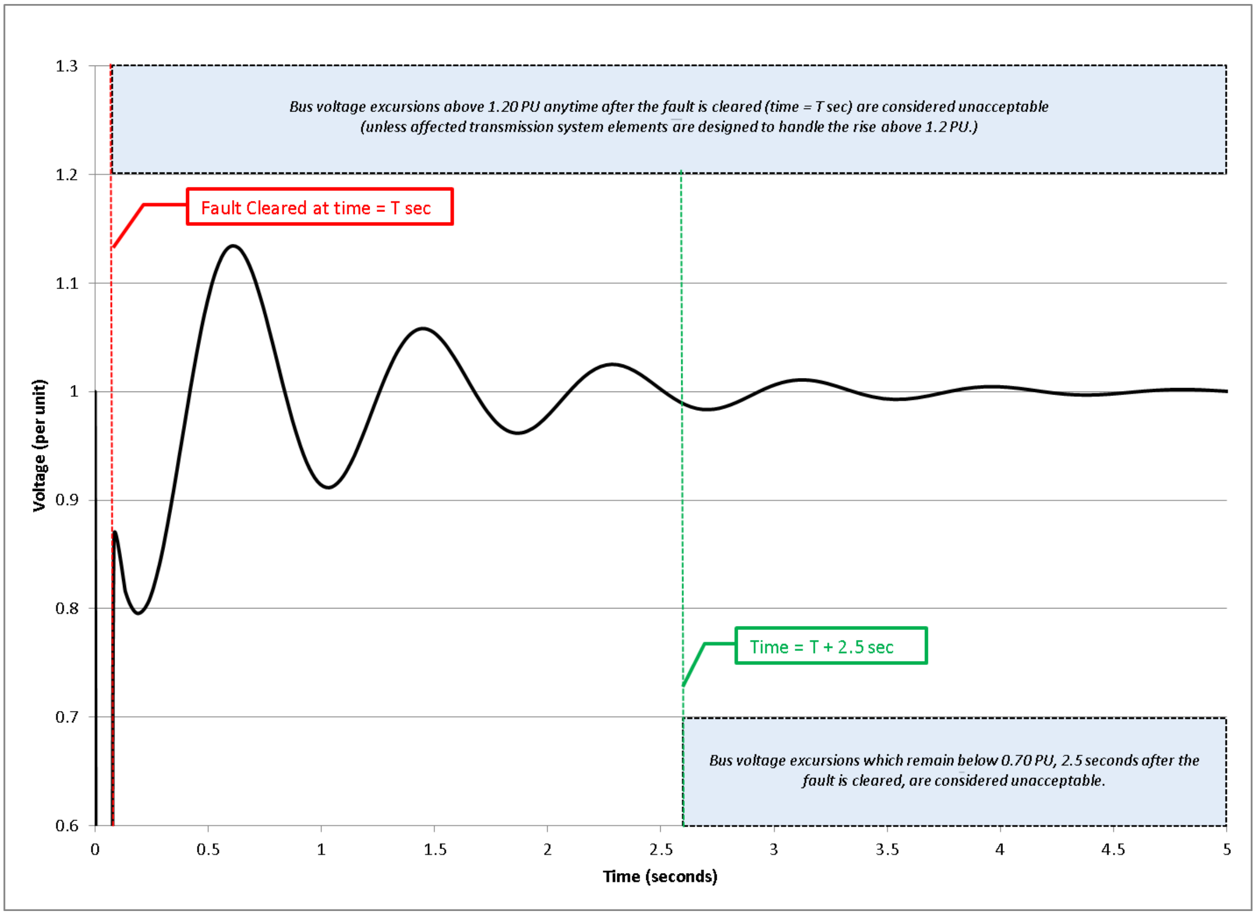


Figure 3. Transient Voltage Recovery Requirement

Appendix D

GEN-2017-023

Dynamic Stability Results with Existing Base Case Issues & Simulation Plots

Table D-1: GEN-2017-023 Dynamic Stability Results w/ Existing DISIS Base Case Issues

Fault ID	25SP			25WP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9027-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9028-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9029-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9030-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9031-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)

Table D-1 Continued

Fault ID	25SP			25WP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9032-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)
FLT9033-3PH	Pass	Pass	Stable (2,3)	Pass	Pass	Stable (2,3)
FLT9034-3PH	Pass	Pass	Stable (2,3)	Pass	Pass	Stable (2,3)
FLT9035-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2)
FLT9036-3PH	Pass	Pass	Stable (1)	Pass	Pass	Stable (1,2)
FLT9037-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)
FLT9038-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)
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
FLT9002-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO3	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO3	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO3	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO3	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO3	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO4	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO4	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO4	Pass	Pass	Stable	Pass	Pass	Stable

Table D-1 Continued

Fault ID	25SP			25WP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9004-PO4	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO4	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO5	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO5	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO5	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO5	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO5	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1011-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1012-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1013-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1014-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1015-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1016-SB	Pass	Pass	Stable	Pass	Pass	Stable

(1) The GEN-2017-156 345 kV (761481) final bus voltage falls below 0.9 p.u. in both the pre and post modification models
(2) Unit G16-095 (587773) does not reach stable active power within 20 seconds in both the pre and post modification models
(3) Unit G16-097 (587793) does not reach stable active power within 20 seconds in both the pre and post modification models

The results of the stability analysis showed that the final bus voltage at GEN-2017-156 345 kV (761481) fell below 0.9 p.u. with the loss of the PITTSB-7 to GEN-2017-156 Ckt 1 345 kV line. This issue was observed under fault FLT9036-3PH in the starting DISIS-2017-002 case and with the GEN-2017-023 modification as shown in Figure D-1 and Figure D-2, respectively. Therefore, the issue was not attributed to the GEN-2017-023 modification request. Note that at the time of this Study, the GEN-2017-156 and GEN-2017-157 interconnection requests were already withdrawn from the SPP Active Queue and as such this issue is no longer relevant.

Figure D-1: FLT9036-3PH Voltage (25SP DISIS Case)

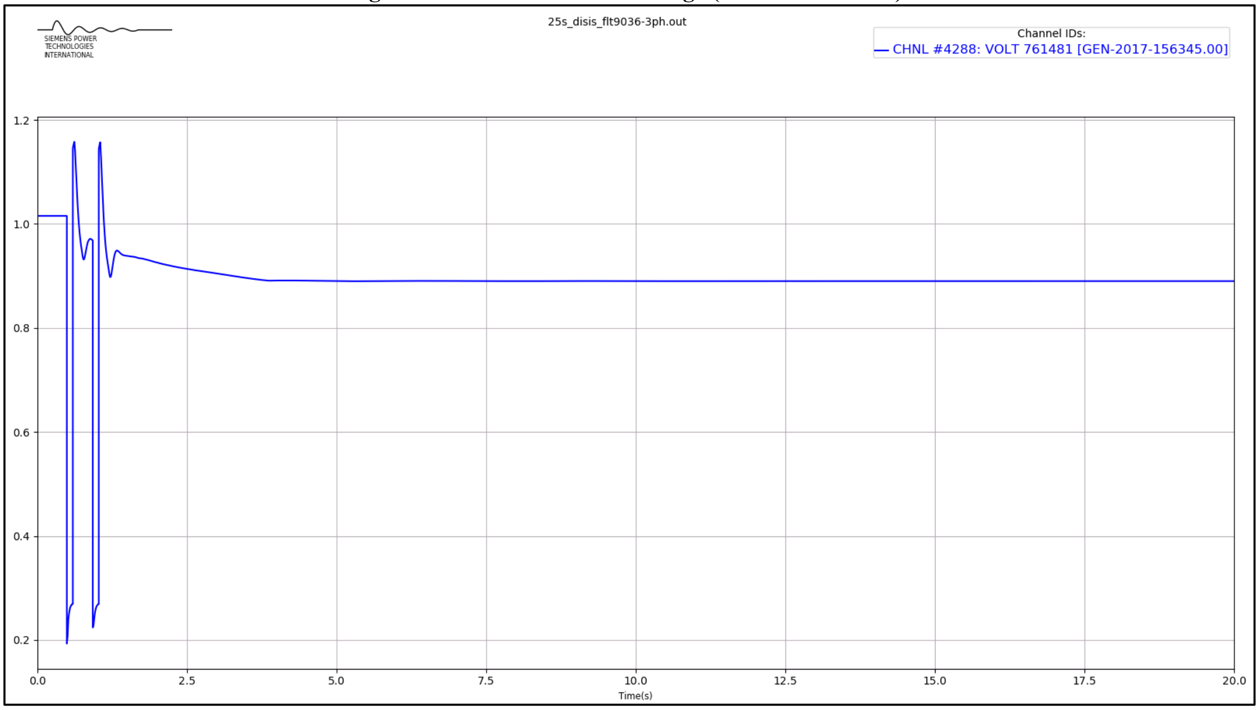
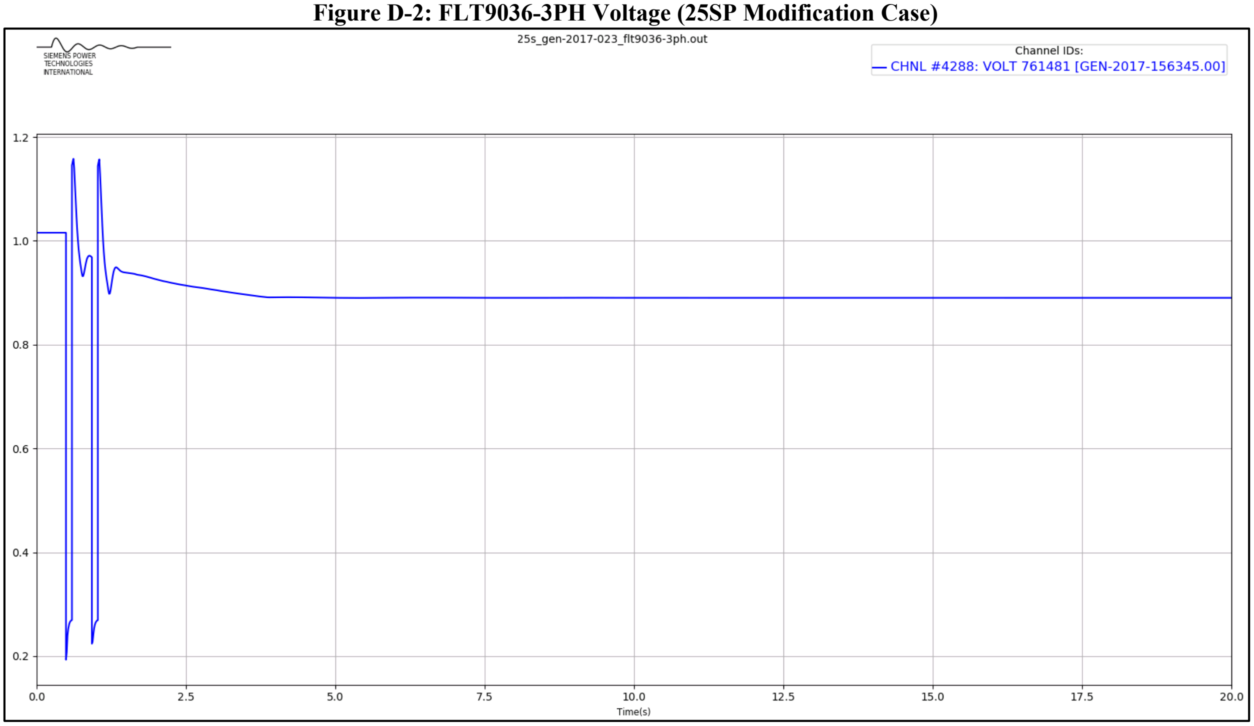


Figure D-2: FLT9036-3PH Voltage (25SP Modification Case)



In addition, GEN-2016-095[1] and GEN-2016-097[1] did not reach stable active power within 20 seconds under several contingencies. For example, this issue was observed under fault FLT9033-3PH in the starting DISIS-2017-002 case and with the GEN-2017-023 modification as shown in Figure D-3 and Figure D-4, respectively. Therefore, the issue was not attributed to the GEN-2017-023 modification request.

Figure D-3: FLT9033-3PH Active Power (25SP DISIS Case)

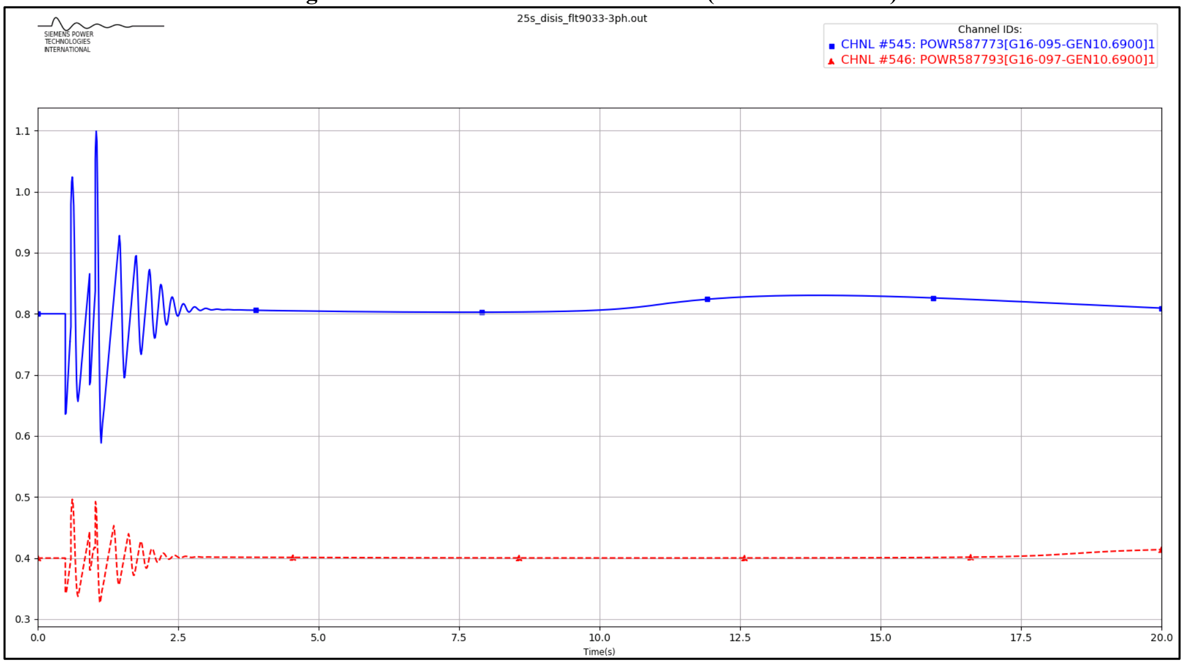
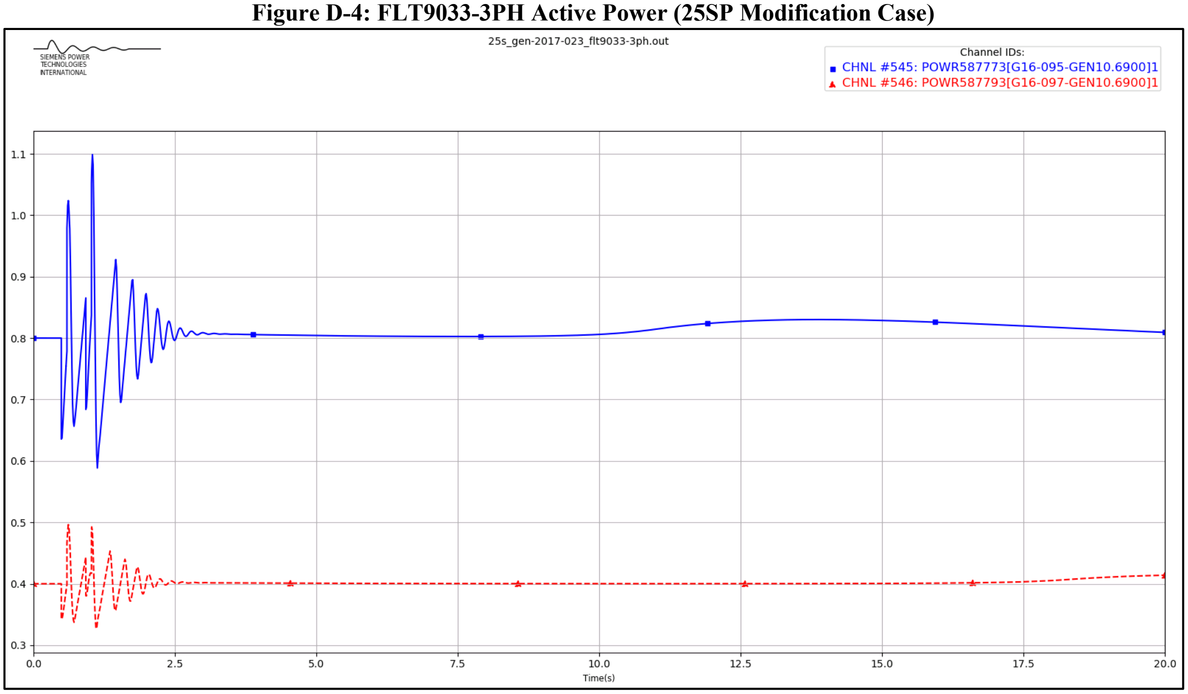


Figure D-4: FLT9033-3PH Active Power (25SP Modification Case)



[1] GEN-2016-095 and GEN-2016-097 were recently modified and the response observed in this study may not be consistent with the latest project model performance.

2025 Summer Peak Plots

Including Prior Outage Plots

GEN-2017-023_25SP_Plots.pdf

2025 Winter Peak Plots

Including Prior Outage Plots

GEN-2017-023_25WP_Plots.pdf