Report on

GEN-2016-102
Modification Request Impact Study

Revision R1 October 1, 2024

Submitted to
Southwest Power Pool

anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
10/01/2024	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-2016-102, an active Generation Interconnection Request (GIR) with a Point of Interconnection (POI) at the Blue River 138 kV Substation.

The GEN-2016-102 project interconnects in the Oklahoma Gas & Electric (OG&E) control area with a capacity of 150.9 MW. This Study has been requested to evaluate the modification of GEN-2016-102 to change the configuration to 5 x Vestas V150 4.3 MW + 28 x Vestas V150 4.5 MW wind turbines for a total dispatch of 147.5 MW.

In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformers, generation interconnection line, auxiliary loads, and reactive power devices. The existing and modified configurations for GEN-2016-102 are shown in Table ES-1 below.

Table ES-1: GEN-2016-102 Modification Request

Facility	Existing Configuration		Modification Configuration	
Point of Interconnection	Blue River 138 kV Substation (515133)		Blue River 138 kV Substation (515133)	
Configuration/Capacity	8 x GE 2.3 MW + 53 x GE 2.5 MW (wind) = 150.9 MW [dispatch]		5 x Vestas V150 4.3 MW + 28 x Vestas V150 4.5 MW (wind) = 147.5 MW [dispatch]	
Generation Interconnection Line	Length = 4 miles R = 0.000440 pu X = 0.004160 pu B = 0.016400 pu Rating MVA = 0.0 MVA		Length = 1.1 miles R = 0.000575 pu X = 0.004235 pu B = 0.001211 pu Rating MVA = 238 MVA	
Main Substation Transformer[1]	X = 8.996%, R = 0.257%, Winding MVA = 96 MVA, Rating MVA = 160 MVA		X12 = 9.498% R12 = 0.208%, X23 = 2.849% R23 = 0.062%, X13 = 14.247% R13 = 0.311%, Winding MVA = 100 MVA, Winding 1, 2, & 3 Rating MVA = 167 MVA	
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 8 X = 5.699%, R = 0.759%, Winding MVA = 22 MVA, Rating MVA = 22 MVA	Gen 2 Equivalent Qty: 53 X = 5.699%, R = 0.759%, Winding MVA = 145.75 MVA, Rating MVA[2] = 145.8 MVA	Gen 1 Equivalent Qty: 5 X = 9.876%, R = 0.693%, Winding MVA = 25.75 MVA, Rating MVA[2] = 25.8 MVA	Gen 2 Equivalent Qty: 28 X = 9.874%, R = 0.71%, Winding MVA = 148.4 MVA, Rating MVA = 148.4 MVA
Equivalent Collector Line[3]	R = 0.004290 pu X = 0.005710 pu B = 0.047860 pu		R = 0.004473 pu X = 0.006422 pu B = 0.056854 pu	
Generator Dynamic Model[4] & Power Factor	8 x GE 2.3 MW (GEWTGCU1)[4] Leading: 0.99 Lagging: 0.99	53 x GE 2.5 MW (GEWTGCU1)[4] Leading: 0.99 Lagging: 0.99	5 x Vestas V150 4.3 MW (CP220961102)[4] Leading: 0.956 Lagging: 0.918	28 x Vestas V150 4.5 MW (CP220961102)[4] Leading: 0.942 Lagging: 0.87
Auxiliary Load	N/A		0.08 MW + 0.06 MVAR on 34.5 kV Bus	
Reactive Power Devices	N/A		2 x 16 MVAR 34.5 kV Capacitor Bank	

1) X and R based on Winding MVA, 2) Rating rounded in PSS/E, 3) All pu are on 100 MVA Base, 4) 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 turbine from GE to Vestas 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-2018-002/2019-001 study models:

- 2025 Summer Peak (25SP),
- 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 reactive power analysis using the 25SP model showed that the GEN-2016-102 project needed a 5.8 MVAr shunt reactor on the 34.5 kV bus of the project substation with the modifications in place, a decrease from the 6.4 MVAr found with the existing configuration. 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-2016-102 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2016-102 POI was 0.52 kA. The maximum three-phase fault current level within 5 buses of the POI was 40.3 kA for the 25SP model. There was a bus with a maximum three-phase fault current over 40 kA. This busis highlighted in Appendix B.

The dynamic stability analysis was performed using Siemens PTI PSS/E version 34.8.0 software for the two modified study models: 25SP and 25WP. 62 fault events were simulated, which included three-phase faults and single-line-to-ground stuck breaker faults.

The results of the dynamic stability analysis showed several existing base case issues that were found in both the original DISIS-2018-002/2019-001 model and in the model with the GEN-2016-102 modification included. These issues were not attributed to the GEN-2016-102 modification request and are detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2016-102 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

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.

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-2016-102. 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.

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.

2.0 Project and Modification Request

The GEN-2016-102 Interconnection Customer requested a modification to its Generation Interconnection Request (GIR) with a Point of Interconnection (POI) at the Blue River 138 kV Substation in the Oklahoma Gas & Electric (OG&E) control area.

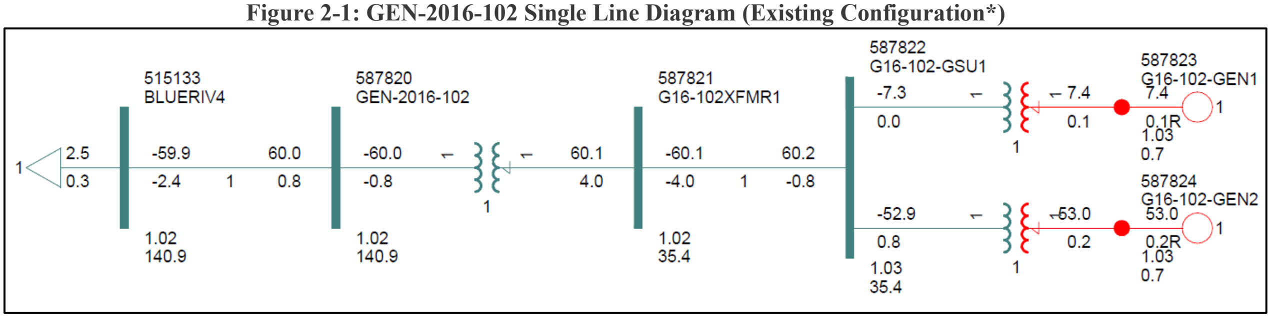
At the time of report posting, GEN-2016-102 is an active Interconnection Request with a queue status of "IA FULLY EXECUTED/ON SCHEDULE." GEN-2016-102 is a wind facility with a maximum summer and winter queue capacity of 150.9 MW with Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (ERIS).

The GEN-2016-102 project is currently in the DISIS-2016-002 cluster. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2016-102 configuration using the DISIS-2018-002/2019-001 25SP stability model.

This Study has been requested to evaluate the modification of GEN-2016-102 to change the configuration to 5 x Vestas V150 4.3 MW + 28 x Vestas V150 4.5 MW wind turbines for a total dispatch of 147.5 MW.

In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformers, generation interconnection line, auxiliary loads, and reactive power devices. Figure 2-2 shows the power flow model single line diagram for the GEN-2016-102 modification. The existing and modified configurations for GEN-2016-102 are shown in Table 2-1 below.

Figure 2-1: GEN-2016-102 Single Line Diagram (Existing Configuration*)



*based on the DISIS-2018-002/2019-001 25SP stability models

Figure 2-2: GEN-2016-102 Single Line Diagram (Modification Configuration)

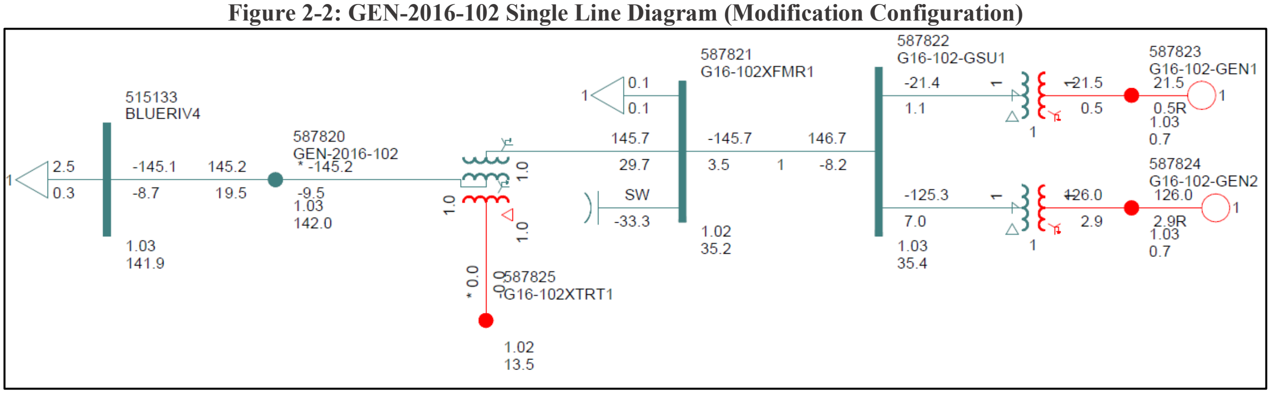


Table 2-1: GEN-2016-102 Modification Request

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</table>

1) X and R based on Winding MVA, 2) Rating rounded in PSS/E, 3) All pu are on 100 MVA Base, 4) 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-2018-002/2019-001 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 turbine change from GE to Vestas turbines. 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 turbine 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-2016-102 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-2016-102 generators, capacitors, and auxiliary/station service loads 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 reduce 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-2018-002/2019-001 stability study model.

4.2 Results

The results from the analysis showed that the GEN-2016-102 project needed approximately 5.8 MVAr of compensation at its collector substation to reduce the MVAr injection at the POI to zero. This is a decrease from the 6.4 MVAr found with the existing configuration. 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 existing configuration. Figure 4-2 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-2016-102	515133	BLUERIV4 138 kV	5.8

Figure 4-1: GEN-2016-102 Existing Single Line Diagram (Shunt Sizes)

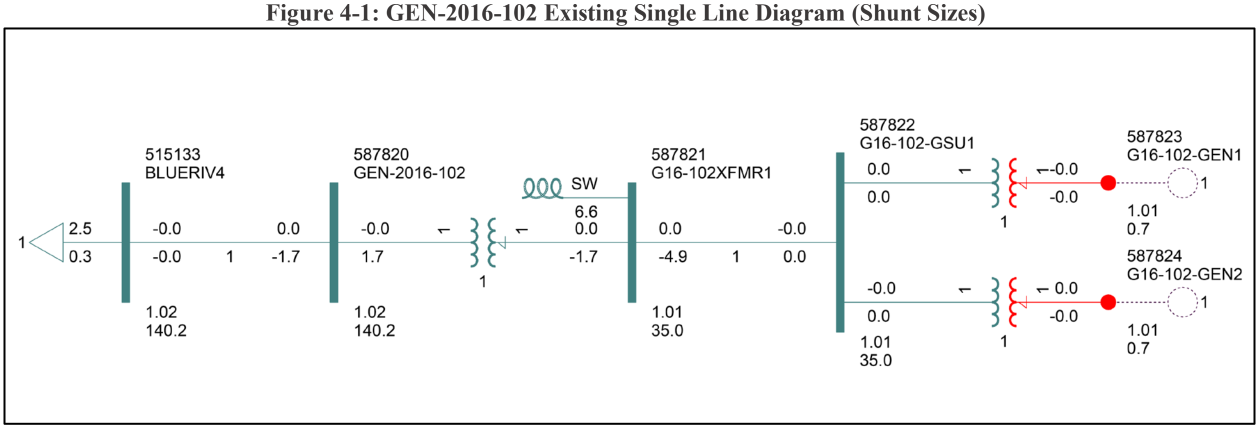
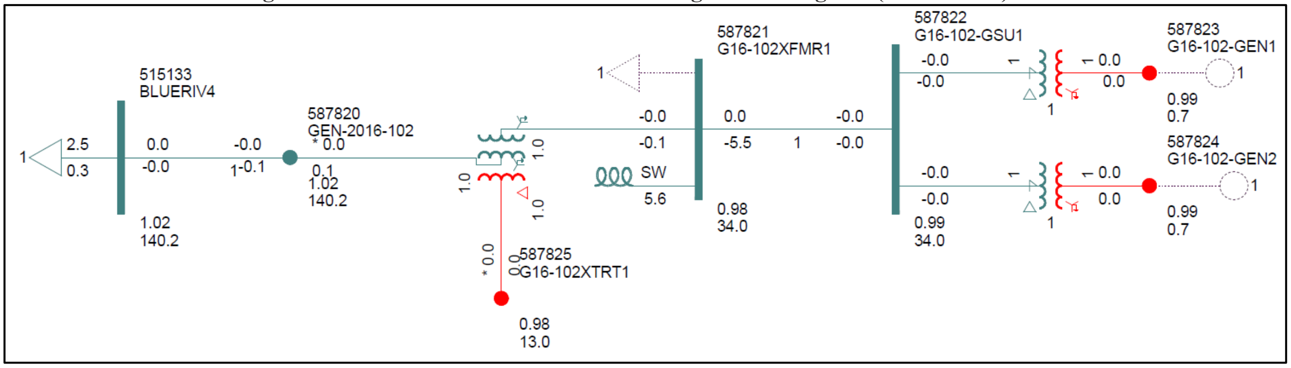


Figure 4-2: GEN-2016-102 Modification Single Line Diagram (Shunt Sizes)



5.0 Short Circuit Analysis

Aneden performed a short circuit study using the 25SP model for GEN-2016-102 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-2016-102 online.

Aneden created a short circuit model using the 25SP DISIS-2018-002/2019-001 stability study model by adjusting the GEN-2016-102 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#	
	587823	587824
Machine MVA Base	21.5	126
R (pu)	0.0	0.0
X'' (pu)	0.93	0.93

*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-2016-102 POI bus (Blue River 138 kV) fault current magnitudes for the comparison cases are provided in Table 5-2 showing a fault current of 10.35 kA with the GEN-2016-102 project online. Table 5-3 shows the maximum fault current magnitudes and fault current increases with the GEN-2016-102 project online.

The maximum fault current calculated within 5 buses of the POI was 40.3 kA for the 25SP model. There was a bus with a maximum three-phase fault current over 40 kA. This busis highlighted in Appendix B. The maximum GEN-2016-102 contribution to three-phase fault currents was about 5.3% and 0.52 kA.

Table 5-2: POI Short Circuit Comparison Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	kA Change	%Change
25SP	9.83	10.35	0.52	5.3%

Table 5-3: 25SP Short Circuit Comparison Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	14.2	0.08	0.6%
138	40.3	0.52	5.3%
345	30.8	0.05	0.2%
Max	**40.3**	**0.52**	**5.3%**

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the modifications to GEN-2016-102. The analysis was performed according to SPP's Disturbance Performance Requirements[2]. 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-2016-102 configuration of 5 x Vestas V150 4.3 MW + 28 x Vestas V150 4.5 MW (CP220961102). This stability analysis was performed using Siemens PTI's PSS/E version 34.8.0 software.

The modifications requested for the GEN-2016-102 project were used to create modified stability models for this impact study based on the DISIS-2018-002/2019-001 stability study models:

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

The dynamic model data for the GEN-2016-102 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:

- 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-2016-102 and other current and prior queued projects in Group 4. In addition, voltages of five (5) buses away from the POI of the GEN-2016-102 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas 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.

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

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 6-1 below. These contingencies were applied to the modified 25SP and 25WP models.

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT1000-SB	P4	Stuck Breaker on BLUERIV4 (515133) 138 kV Bus a. Apply single phase fault at the BLUERIV4 (515133) 138 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the BLUERIV4 (515133) 138 kV to ARBUCKL4 (515117) 138 kV line CKT 1. b.2.Trip the BLUERIV4 (515133) 138 kV to PARKLN 4 (515178) 138 kV line CKT 1. Trip generator(s) on the Bus G16-102-GEN1 (587823) 0.72 kV Trip generator(s) on the Bus G16-102-GEN2 (587824) 0.72 kV
FLT1001-SB	P4	Stuck Breaker on ARBUCKL4 (515117) 138 kV Bus a. Apply single phase fault at the ARBUCKL4 (515117) 138 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the ARBUCKL4 (515117) 138 kV to VANOSTP4 (515531) 138 kV line CKT 1. b.2.Trip the ARBUCKL4 (515117) 138 kV to MILLCKT4 (515121) 138 kV line CKT 1. b.3.Trip the ARBUCKL4 (515117) 138 kV to GEN-2016-126 (588180) 138 kV line CKT 1. b.4.Trip the ARBUCKL4 (515117) 138 kV to SULPHR 4 (515559) 138 kV line CKT 1. Trip generator(s) on the Bus G16-126-GEN1 (588183) 0.65 kV
FLT1002-SB	P4	Stuck Breaker on ARBUCKL4 (515117) 138 kV Bus a. Apply single phase fault at the ARBUCKL4 (515117) 138 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the ARBUCKL4 (515117) 138 kV to BLUERIV4 (515133) 138 kV line CKT 1. b.2.Trip the ARBUCKL4 (515117) 138 kV to BERWYN 4 (515173) 138 kV line CKT 1. b.3.Trip the ARBUCKL4 (515117) 138 kV to OAKLAW-4 (515123) 138 kV line CKT 1. b.4.Trip the ARBUCKL4 (515117) 138 kV / ARBUCKL2 (515116) 69 kV / ARBUCKL1 (515702) 13.2 kV XFMR CKT 1.
FLT1003-SB	P4	Stuck Breaker on ARBUCKL2 (515116) 69 kV Bus a. Apply single phase fault at the ARBUCKL2 (515116) 69 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip bus ARBUCKL2 (515116) 69 kV.
FLT1004-SB	P4	Stuck Breaker on PARKLN 4 (515178) 138 kV Bus a. Apply single phase fault at the PARKLN 4 (515178) 138 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the PARKLN 4 (515178) 138 kV to BLUERIV4 (515133) 138 kV line CKT 1. b.2.Trip the PARKLN 4 (515178) 138 kV to SOTHADA4 (515318) 138 kV line CKT 1. b.3.Trip the PARKLN 4 (515178) 138 kV to LKKONWA4 (515977) 138 kV line CKT 1. b.4.Trip the PARKLN 4 (515178) 138 kV / PARKLN 2 (515177) 69 kV / PARKLN21 (515748) 13.2 kV XFMR CKT 1.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT1005-SB	P4	Stuck Breaker on PARKLN 4 (515178) 138 kV Bus a. Apply single phase fault at the PARKLN 4 (515178) 138 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the PARKLN 4 (515178) 138 kV to VANOSS 4 (515174) 138 kV line CKT 1. b.2.Trip the PARKLN 4 (515178) 138 kV / PARKLN 2 (515177) 69 kV / PARKLN11 (515747) 13.2 kV XFMR CKT 1. b.3. Trip LOAD PARKLN 4 (515178) 138 kV #1
FLT1006-SB	P4	Stuck Breaker on PARKLN 2 (515177) 69 kV Bus a. Apply single phase fault at the PARKLN 2 (515177) 69 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the PARKLN 2 (515177) 69 kV to ADAINDU2 (515384) 69 kV line CKT 1. b.2.Trip the PARKLN 2 (515177) 69 kV to BYNGSPA2 (515179) 69 kV line CKT 1. b.3.Trip the PARKLN 2 (515177) 69 kV / PARKLN 4 (515178) 138 kV / PARKLN21 (515748) 13.2 kV XFMR CKT 1.
FLT1007-SB	P4	Stuck Breaker on PARKLN 2 (515177) 69 kV Bus a. Apply single phase fault at the PARKLN 2 (515177) 69 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip the PARKLN 2 (515177) 69 kV to IDEAL 2 (515175) 69 kV line CKT 1. b.2.Trip the PARKLN 2 (515177) 69 kV / PARKLN 4 (515178) 138 kV / PARKLN11 (515747) 13.2 kV XFMR CKT 1. b.3. Trip SWITCHED SHUNT PARKLN 2 (515177) 69 kV
FLT1008-SB	P4	Stuck Breaker on GEN-2016-102 (587820) 138 kV Bus a. Apply single phase fault at the GEN-2016-102 (587820) 138 kV Bus b. Clear fault after 16 cycles and trip the following elements: b.1.Trip bus GEN-2016-102 (587820) 138 kV. Trip generator(s) on the Bus G16-102-GEN1 (587823) 0.72 kV Trip generator(s) on the Bus G16-102-GEN2 (587824) 0.72 kV
FLT9000-3PH	P1	3 Phase fault on BLUERIV4 (515133) 138 kV to GEN-2016-102 (587820) 138 kV line CKT 1, near BLUERIV4 (515133) 138 kV. a. Apply fault at the BLUERIV4 (515133) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. Trip generator(s) on the Bus G16-102-GEN1 (587823) 0.72 kV Trip generator(s) on the Bus G16-102-GEN2 (587824) 0.72 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 BLUERIV4 (515133) 138 kV to ARBUCKL4 (515117) 138 kV line CKT 1, near BLUERIV4 (515133) 138 kV. a. Apply fault at the BLUERIV4 (515133) 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.
FLT9002-3PH	P1	3 Phase fault on BLUERIV4 (515133) 138 kV to PARKLN 4 (515178) 138 kV line CKT 1, near BLUERIV4 (515133) 138 kV. a. Apply fault at the BLUERIV4 (515133) 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.
FLT9003-3PH	P1	3 Phase fault on GEN-2016-102 (587820) 138 kV to BLUERIV4 (515133) 138 kV line CKT 1, near GEN-2016-102 (587820) 138 kV. a. Apply fault at the GEN-2016-102 (587820) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. Trip generator(s) on the Bus G16-102-GEN1 (587823) 0.72 kV Trip generator(s) on the Bus G16-102-GEN2 (587824) 0.72 kV

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9004-3PH	P1	3 Phase fault on GEN-2016-102 (587820) 138 kV / G16-102XFMR1 (587821) 34.5 kV / G16-102XTRT1 (587825) 13.2 kV XFMR CKT 1, near GEN-2016-102 (587820) 138 kV. a. Apply fault at the GEN-2016-102 (587820) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer. Trip generator(s) on the Bus G16-102-GEN1 (587823) 0.72 kV Trip generator(s) on the Bus G16-102-GEN2 (587824) 0.72 kV
FLT9005-3PH	P1	3 Phase fault on PARKLN 4 (515178) 138 kV to BLUERIV4 (515133) 138 kV line CKT 1, near PARKLN 4 (515178) 138 kV. a. Apply fault at the PARKLN 4 (515178) 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.
FLT9006-3PH	P1	3 Phase fault on PARKLN 4 (515178) 138 kV to VANOSS 4 (515174) 138 kV line CKT 1, near PARKLN 4 (515178) 138 kV. a. Apply fault at the PARKLN 4 (515178) 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.
FLT9007-3PH	P1	3 Phase fault on PARKLN 4 (515178) 138 kV to LKKONWA4 (515977) 138 kV line CKT 1, near PARKLN 4 (515178) 138 kV. a. Apply fault at the PARKLN 4 (515178) 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.
FLT9008-3PH	P1	3 Phase fault on PARKLN 4 (515178) 138 kV to SOTHADA4 (515318) 138 kV line CKT 1, near PARKLN 4 (515178) 138 kV. a. Apply fault at the PARKLN 4 (515178) 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.
FLT9009-3PH	P1	3 Phase fault on PARKLN 4 (515178) 138 kV / PARKLN 2 (515177) 69 kV / PARKLN11 (515747) 13.2 kV XFMR CKT 1, near PARKLN 4 (515178) 138 kV. a. Apply fault at the PARKLN 4 (515178) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
FLT9010-3PH	P1	3 Phase fault on PARKLN 2 (515177) 69 kV / PARKLN 4 (515178) 138 kV / PARKLN11 (515747) 13.2 kV XFMR CKT 1, near PARKLN 2 (515177) 69 kV. a. Apply fault at the PARKLN 2 (515177) 69 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
FLT9011-3PH	P1	3 Phase fault on PARKLN 2 (515177) 69 kV to IDEAL 2 (515175) 69 kV line CKT 1, near PARKLN 2 (515177) 69 kV. a. Apply fault at the PARKLN 2 (515177) 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 PARKLN 2 (515177) 69 kV to ADAINDU2 (515384) 69 kV line CKT 1, near PARKLN 2 (515177) 69 kV. a. Apply fault at the PARKLN 2 (515177) 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 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9013-3PH	P1	3 Phase fault on PARKLN 2 (515177) 69 kV to BYNGSPA2 (515179) 69 kV line CKT 1, near PARKLN 2 (515177) 69 kV. a. Apply fault at the PARKLN 2 (515177) 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 IDEAL 2 (515175) 69 kV to PARKLN 2 (515177) 69 kV line CKT 1, near IDEAL 2 (515175) 69 kV. a. Apply fault at the IDEAL 2 (515175) 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 ADAINDU2 (515384) 69 kV to PARKLN 2 (515177) 69 kV line CKT 1, near ADAINDU2 (515384) 69 kV. a. Apply fault at the ADAINDU2 (515384) 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 ADAINDU2 (515384) 69 kV to VALLYVU2 (515182) 69 kV line CKT 1, near ADAINDU2 (515384) 69 kV. a. Apply fault at the ADAINDU2 (515384) 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 BYNGSPA2 (515179) 69 kV to PARKLN 2 (515177) 69 kV line CKT 1, near BYNGSPA2 (515179) 69 kV. a. Apply fault at the BYNGSPA2 (515179) 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 BYNGSPA2 (515179) 69 kV to SASAKWT2 (515094) 69 kV line CKT 1, near BYNGSPA2 (515179) 69 kV. a. Apply fault at the BYNGSPA2 (515179) 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.
FLT9019-3PH	P1	3 Phase fault on SOTHADA4 (515318) 138 kV to PARKLN 4 (515178) 138 kV line CKT 1, near SOTHADA4 (515318) 138 kV. a. Apply fault at the SOTHADA4 (515318) 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.
FLT9020-3PH	P1	3 Phase fault on SOTHADA4 (515318) 138 kV to HARDEN 4 (515362) 138 kV line CKT 1, near SOTHADA4 (515318) 138 kV. a. Apply fault at the SOTHADA4 (515318) 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.
FLT9021-3PH	P1	3 Phase fault on LKKONWA4 (515977) 138 kV to PARKLN 4 (515178) 138 kV line CKT 1, near LKKONWA4 (515977) 138 kV. a. Apply fault at the LKKONWA4 (515977) 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.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9022-3PH	P1	3 Phase fault on LKKONWA4 (515977) 138 kV to SEMINOL4 (515044) 138 kV line CKT 1, near LKKONWA4 (515977) 138 kV. a. Apply fault at the LKKONWA4 (515977) 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.
FLT9023-3PH	P1	3 Phase fault on VANOSS 4 (515174) 138 kV to PARKLN 4 (515178) 138 kV line CKT 1, near VANOSS 4 (515174) 138 kV. a. Apply fault at the VANOSS 4 (515174) 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.
FLT9024-3PH	P1	3 Phase fault on VANOSS 4 (515174) 138 kV to VANOSTP4 (515531) 138 kV line CKT 1, near VANOSS 4 (515174) 138 kV. a. Apply fault at the VANOSS 4 (515174) 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.
FLT9025-3PH	P1	3 Phase fault on VANOSTP4 (515531) 138 kV to VANOSS 4 (515174) 138 kV line CKT 1, near VANOSTP4 (515531) 138 kV. a. Apply fault at the VANOSTP4 (515531) 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 VANOSTP4 (515531) 138 kV to SEMINOL4 (515044) 138 kV line CKT 1, near VANOSTP4 (515531) 138 kV. a. Apply fault at the VANOSTP4 (515531) 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 VANOSTP4 (515531) 138 kV to ARBUCKL4 (515117) 138 kV line CKT 1, near VANOSTP4 (515531) 138 kV. a. Apply fault at the VANOSTP4 (515531) 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 ARBUCKL4 (515117) 138 kV to VANOSTP4 (515531) 138 kV line CKT 1, near ARBUCKL4 (515117) 138 kV. a. Apply fault at the ARBUCKL4 (515117) 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 ARBUCKL4 (515117) 138 kV to BERWYN 4 (515173) 138 kV line CKT 1, near ARBUCKL4 (515117) 138 kV. a. Apply fault at the ARBUCKL4 (515117) 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.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9030-3PH	P1	3 Phase fault on ARBUCKL4 (515117) 138 kV to MILLCKT4 (515121) 138 kV line CKT 1, near ARBUCKL4 (515117) 138 kV. a. Apply fault at the ARBUCKL4 (515117) 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 ARBUCKL4 (515117) 138 kV to OAKLAW-4 (515123) 138 kV line CKT 1, near ARBUCKL4 (515117) 138 kV. a. Apply fault at the ARBUCKL4 (515117) 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 ARBUCKL4 (515117) 138 kV to SULPHR 4 (515559) 138 kV line CKT 1, near ARBUCKL4 (515117) 138 kV. a. Apply fault at the ARBUCKL4 (515117) 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 ARBUCKL4 (515117) 138 kV to GEN-2016-126 (588180) 138 kV line CKT 1, near ARBUCKL4 (515117) 138 kV. a. Apply fault at the ARBUCKL4 (515117) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. Trip generator(s) on the Bus G16-126-GEN1 (588183) 0.65 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.
FLT9034-3PH	P1	3 Phase fault on ARBUCKL4 (515117) 138 kV to BLUERIV4 (515133) 138 kV line CKT 1, near ARBUCKL4 (515117) 138 kV. a. Apply fault at the ARBUCKL4 (515117) 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 ARBUCKL4 (515117) 138 kV / ARBUCKL2 (515116) 69 kV / ARBUCKL1 (515702) 13.2 kV XFMR CKT 1, near ARBUCKL4 (515117) 138 kV. a. Apply fault at the ARBUCKL4 (515117) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
FLT9036-3PH	P1	3 Phase fault on ARBUCKL2 (515116) 69 kV / ARBUCKL4 (515117) 138 kV / ARBUCKL1 (515702) 13.2 kV XFMR CKT 1, near ARBUCKL2 (515116) 69 kV. a. Apply fault at the ARBUCKL2 (515116) 69 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
FLT9037-3PH	P1	3 Phase fault on ARBUCKL2 (515116) 69 kV to DAVS 2 (515111) 69 kV line CKT 1, near ARBUCKL2 (515116) 69 kV. a. Apply fault at the ARBUCKL2 (515116) 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.
FLT9038-3PH	P1	3 Phase fault on DAVS 2 (515111) 69 kV to ARBUCKL2 (515116) 69 kV line CKT 1, near DAVS 2 (515111) 69 kV. a. Apply fault at the DAVS 2 (515111) 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 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9039-3PH	P1	3 Phase fault on DAVS 2 (515111) 69 kV to LAKEARB2 (515194) 69 kV line CKT 1, near DAVS 2 (515111) 69 kV. a. Apply fault at the DAVS 2 (515111) 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.
FLT9040-3PH	P1	3 Phase fault on DAVS 2 (515111) 69 kV to WNREF1T2 (515110) 69 kV line CKT 1, near DAVS 2 (515111) 69 kV. a. Apply fault at the DAVS 2 (515111) 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.
FLT9041-3PH	P1	3 Phase fault on GEN-2016-126 (588180) 138 kV to ARBUCKL4 (515117) 138 kV line CKT 1, near GEN-2016-126 (588180) 138 kV. a. Apply fault at the GEN-2016-126 (588180) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted line. Trip generator(s) on the Bus G16-126-GEN1 (588183) 0.65 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.
FLT9042-3PH	P1	3 Phase fault on GEN-2016-126 (588180) 138 kV to G16-126XFMR1 (588181) 34.5 kV XFMR CKT 1, near GEN-2016-126 (588180) 138 kV. a. Apply fault at the GEN-2016-126 (588180) 138 kV Bus. b. Clear fault after 7 cycles by tripping the faulted transformer. Trip generator(s) on the Bus G16-126-GEN1 (588183) 0.65 kV
FLT9043-3PH	P1	3 Phase fault on SULPHR 4 (515559) 138 kV to ARBUCKL4 (515117) 138 kV line CKT 1, near SULPHR 4 (515559) 138 kV. a. Apply fault at the SULPHR 4 (515559) 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.
FLT9044-3PH	P1	3 Phase fault on SULPHR 4 (515559) 138 kV to JOLLYVL4 (515118) 138 kV line CKT 1, near SULPHR 4 (515559) 138 kV. a. Apply fault at the SULPHR 4 (515559) 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.
FLT9045-3PH	P1	3 Phase fault on OAKLAW-4 (515123) 138 kV to ARBUCKL4 (515117) 138 kV line CKT 1, near OAKLAW-4 (515123) 138 kV. a. Apply fault at the OAKLAW-4 (515123) 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.
FLT9046-3PH	P1	3 Phase fault on OAKLAW-4 (515123) 138 kV to OAKLAWN4 (521019) 138 kV line CKT Z1, near OAKLAW-4 (515123) 138 kV. a. Apply fault at the OAKLAW-4 (515123) 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.
FLT9047-3PH	P1	3 Phase fault on OAKLAW-4 (515123) 138 kV to CHIGLEY4 (515114) 138 kV line CKT 1, near OAKLAW-4 (515123) 138 kV. a. Apply fault at the OAKLAW-4 (515123) 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.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9048-3PH	P1	3 Phase fault on MILLCKT4 (515121) 138 kV to ARBUCKL4 (515117) 138 kV line CKT 1, near MILLCKT4 (515121) 138 kV. a. Apply fault at the MILLCKT4 (515121) 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.
FLT9049-3PH	P1	3 Phase fault on MILLCKT4 (515121) 138 kV to MILLCRK4 (515196) 138 kV line CKT 1, near MILLCKT4 (515121) 138 kV. a. Apply fault at the MILLCKT4 (515121) 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.
FLT9050-3PH	P1	3 Phase fault on MILLCKT4 (515121) 138 kV to SXMLCKT4 (515122) 138 kV line CKT 1, near MILLCKT4 (515121) 138 kV. a. Apply fault at the MILLCKT4 (515121) 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.
FLT9051-3PH	P1	3 Phase fault on BERWYN 4 (515173) 138 kV to ARBUCKL4 (515117) 138 kV line CKT 1, near BERWYN 4 (515173) 138 kV. a. Apply fault at the BERWYN 4 (515173) 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.
FLT9052-3PH	P1	3 Phase fault on BERWYN 4 (515173) 138 kV to AIRPRKT4 (515169) 138 kV line CKT 1, near BERWYN 4 (515173) 138 kV. a. Apply fault at the BERWYN 4 (515173) 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.

6.3 Results

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

Table 6-2: GEN-2016-102 Dynamic Stability Results

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 6-2 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
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
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

Table 6-2 continued

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	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

The results of the dynamic stability showed several existing base case issues that were found in both the original DISIS-2018-002/2019-001 model and the model with the GEN-2016-102 modification included. These issues were not attributed to the GEN-2016-102 modification request and detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2016-102 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 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.

7.1 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-2016-102 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.