GEN-2003-019

Impact Restudy for Generator Modification

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By SPP Generator Interconnections Dept.

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
06/25/2020	SPP	Initial report issued.
07/10/2020	SPP	Report Revised to reflect correct Phase II Generation Interconnection Line Data
07/14/2020	SPP	Corrected Shunt Reactor value in Summary Section

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SUMMARY

The GEN-2003-019 Interconnection Customer has requested a modification to Phase I of its 249.3 MW Interconnection Request. This system impact restudy was performed to determine the effects of changing its Phase I turbines from 56 Vestas V-80 1.8 MW wind turbine generators (for a total of 100.8 MW) to 49 Vestas V-80 1.8 MW and 7 Vestas V-100 1.8 MW wind turbine generators (for a total of 100.8 MW). Also, the modification request included changes to the generation interconnection line, collection system, main substation transformer, and the generator substation transformer. The point of interconnection (POI) for GEN-2003-019 remains at the Smokey Hills 230kV Substation.

A system impact restudy was performed by Aneden Consulting to help determine whether the requested modification is a Material Modification. A Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later Queue priority date. Dynamic stability and low-wind/no-wind condition analyses were performed for this modification request. The full study report follows this executive summary.

The results of the dynamic stability analysis showed that, with the GEN-2003-019 requested modification implemented, all fault events from a full system intact state resulted in a stable response following each studied event. There were no damping or voltage recovery violations observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride-Through (LVRT) requirements of FERC Order #661A.

Given the results of the impact analysis, the requested modification is not considered a Material Modification; the requested modification does not have a material impact on the cost or timing of any Interconnection Request with a later Queue priority date.

Per 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.

Additionally, the project may require a 5.48 MVAr shunt reactor on the 34.5 kV bus of the Phase I project substation which is an increase from the existing model representation which required 1.2 MVAr. Phase II of the GEN-2003-019 project may require a 6.94 MVAr shunt reactor on the 34.5 kV bus of the Phase II project substation, an increase from the existing model representation which did not require reactive power. This is necessary to offset the capacitive effect on the transmission network caused by the project’s transmission line and collector system during low-wind/no-wind conditions. The customer may elect to provide reactive compensation by other equipment and it is the customer’s responsibility to design and verify the compensation.

In real-time operation, the customer may be required to reduce its generation output to 0 MW, 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.

A: CONSULTANT'S MATERIAL MODIFICATION STUDY REPORT

See next page for the Consultant's Material Modification Study report.

Submitted to

Southwest Power Pool

SPP Southwest Power Pool

Report On

GEN-2003-019
Modification Request Impact Study

Revision R1

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anedenconsulting.com

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Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for Phase I of GEN-2003-019, an active generation interconnection request with a point of interconnection (POI) at the Smokey Hills 230 kV substation.

The GEN-2003-019 project is interconnected in the Midwest Energy (MIDW) control area with a capacity of 249.3 MW as shown in Table ES-1 below. The GEN-2003-019 Phase I Modification Request included a repowering of the 56 Vestas V-80 1.8 MW Wind Turbine Generators to a total of 49 x Vestas V-80 1.8MW + 7 x Vestas V-100 1.8 MW turbines, for a total capacity of 100.8 MW. In addition, the Phase I modification request included changes to the collection system, generator substation transformer, and main substation transformer. The Phase II collection system, generator substation transformer, generation interconnection line, and main substation transformer were also updated with the latest project information to ensure accurate results. The Phase I modification request changes and updates are shown in Table ES-2, and the Phase II updates are shown in Table ES-3.

Table ES-1: Existing GEN-2003-019 Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2003-019	249.3	56 x Vestas V-80 1.8MW (Phase I) = 100.8 MW 99 x GE 1.5MW (Phase II) = 148.5 MW	Smokey Hills 230 kV (530592)

Table ES-2: GEN-2003-019 Phase I Modification Request

Facility	Existing	Modification	
Point of Interconnection	Smokey Hills 230 kV (530592)	Smokey Hills 230 kV (530592)	
Configuration/Capacity	56 x Vestas V-80 1.8MW = 100.8 MW	49 x Vestas V-80 1.8MW + 7 x Vestas V-100 1.8 MW = 100.8 MW	
Generation Interconnection Line	Length = 4.74 miles R = 0.001050 pu X = 0.007050 pu B = 0.013670 pu	Length = 4.74 miles R = 0.001050 pu X = 0.007050 pu B = 0.013670 pu	
Main Substation Transformer	X12 = 12.56%, R12 = 0.28%, X23 = 3.30%, R23 = 0.00%, X13 = 13.30%, R13 = 0.00% Winding 1-2 69 MVA, Winding 2-3 100 MVA, Rating 115 MVA	X = 8.72%, R = 0.21%, Winding 69 MVA, Rating 115 MVA	
GSU Transformer	Gen 1 Equivalent Qty: 56 X = 7.5%, R = 0.00%, Winding and Rating 117.6 MVA	Gen 1 Equivalent Qty: 49: X = 7.46%, R = 0.78%, Rating 90.7 MVA	Gen 2 Equivalent Qty: 7: X = 9.76%, R = 0.895%, Rating 16.1 MVA
Equivalent Collector Line	N/A	R = 0.005937 pu X = 0.011562 pu B = 0.041132 pu	
Generator Bus Power Factor	0.99 Leading and Lagging from the generator Additional Reactive Power Compensator at Gen Bus Modeled as: 1 x 16.78 MVAR Capacitor Bank 1 x 31.61 MVAR Capacitor Bank	Unity from the Generator N/A	
Reactive Power Devices	1 x 9 MVAR 34.5 kV Shunt Reactor 1 x 8 MVAR 34.5 kV Capacitor Bank	1 x 9 MVAR 34.5 kV Shunt Reactor 1 x 8 MVAR 34.5 kV Capacitor Bank	

Table ES-3: GEN-2003-019 Phase II Updates

Facility	Existing	Updated
Point of Interconnection	Smokey Hills 230 kV (530592)	Smokey Hills 230 kV (530592)
Configuration/Capacity	99 x GE 1.5MW = 148.5 MW	99 x GE 1.5MW = 148.5 MW
Generation Interconnection Line	Length = 2.7 miles R = 0.000600 pu X = 0.004020 pu B = 0.007790 pu	Length = 2.7 miles R = 0.000600 pu X = 0.004020 pu B = 0.007790 pu
Main Substation Transformer	X12 = 8.5%, R12 = 0.18%, X23 = 2.57%, R23 = 0.00%, X13 = 9.25%, R13 = 0.00% Winding 1-2 102.6 MVA, Winding 2-3 100 MVA, Rating 171 MVA	X = 14.49%, R = 0.32%, Winding and Rating 171 MVA
GSU Transformer	Gen 1 Equivalent Qty: 99 X = 5.7%, R = 0.76%, Winding and Rating 173.3 MVA	Gen 1 Equivalent Qty: 99 X = 5.7%, R = 0.76%, Winding and Rating 173.3 MVA
Equivalent Collector Line	N/A	R = 0.006321 pu X = 0.009117 pu B = 0.061603 pu

Aneden performed reactive power analysis, short circuit analysis, and dynamic stability analysis using the modification request data on the initial DISIS-2016-002 Group 4 study models. All analyses were performed using the PTI PSS/E version 33.7 software and the results are summarized below.

The results of the reactive power analysis, also known as the low-wind/no-wind condition analysis, showed that Phase I of the GEN-2003-019 project may require a 5.48 MVAr shunt reactor on the 34.5 kV bus of the Phase I project substation which is an increase from the existing model representation which required 1.2 MVAr. Phase II of the GEN-2003-019 project may require a 6.94 MVAr shunt reactor on the 34.5 kV bus of the Phase II project substation, an increase from the existing model representation which did not require reactive power. A shunt reactor is needed to reduce the reactive power transfer at the POI to approximately zero during low/no wind conditions while Phase I and Phase II of the generation interconnection project remains connected to the grid.

The results from the short circuit analysis with the updated topology showed that the maximum Phase I GEN-2003-019 contribution to three-phase fault currents in the immediate systems at or near GEN-2003-019 was not greater than 0.50 kA for the 2018SP and 2026SP cases. All three-phase fault current levels within 5 buses of the POI with the GEN-2003-019 Phase I and Phase II generators online were below 27 kA for the 2018SP models and 2026SP models.

The dynamic stability analysis was performed using three DISIS-2016-002 models, 2017 Winter Peak, 2018 Summer Peak, 2026 Summer Peak. Up to 59 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

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

1.0 Introduction

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for Phase I of GEN-2003-019, an active generation interconnection request with a point of interconnection (POI) at the Smokey Hills 230 kV Substation.

The GEN-2003-019 project consists of two phases and is proposed to interconnect in the Midwest Energy (MIDW) control area with a combined capacity of 249.3 MW as shown in Table 1-1 below. Details of the modification request is provided in Section 2.0 below.

Table 1-1: Existing GEN-2003-019 Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2003-019	249.3	56 x Vestas V-80 1.8MW (Phase I) = 100.8 MW 99 x GE 1.5MW (Phase II) = 148.5 MW	Smokey Hills 230 kV (530592)

1.1 Scope

The Study included reactive power, short circuit, and dynamic stability analyses. The methodology, assumptions, and results of the analyses are presented in the following five main sections:

1. Project and Modification Request
2. Reactive Power Analysis
3. Short Circuit Analysis
4. Dynamic Stability Analysis
5. Conclusions

The analyses were completed using a set of modified study models developed using the modification request data and the three DISIS-2016-002 study models:

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

All analyses were performed using the PTI PSS/E version 33.7 software. The results of each analysis are presented in the following sections.

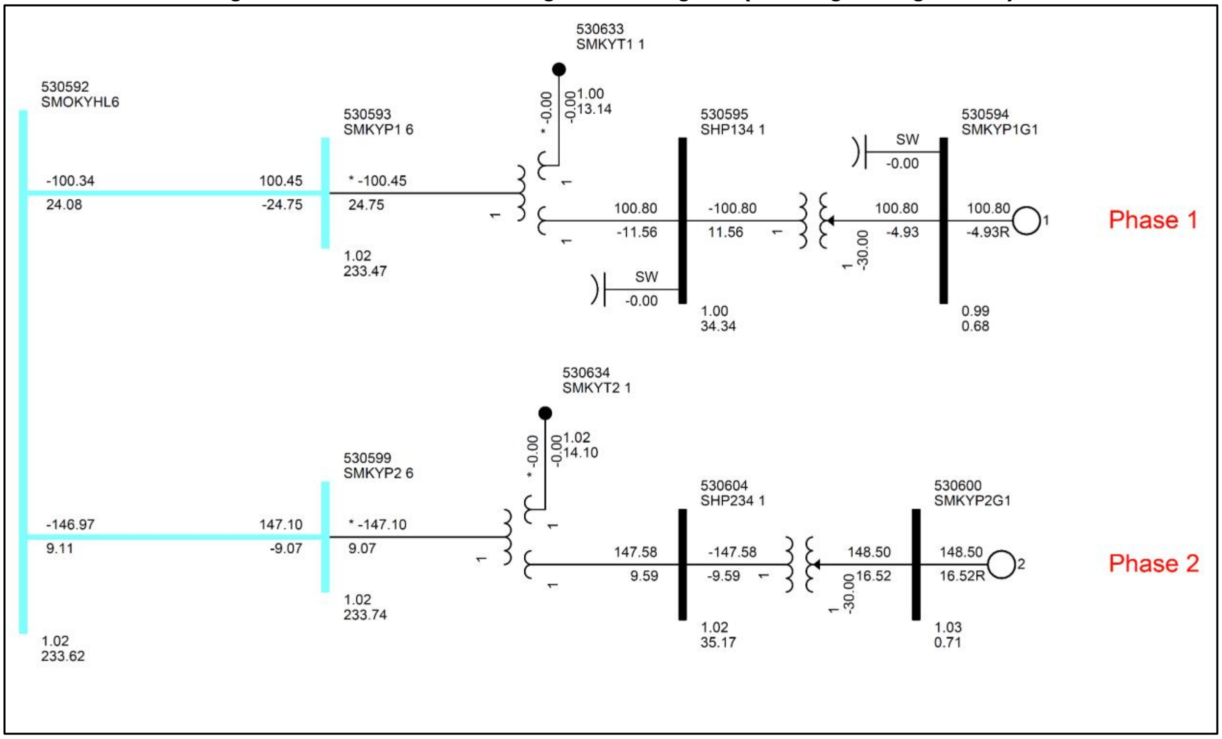
1.2 Study Limitations

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

GEN-2003-019 was last studied in an impact study completed in November of 2007[1]. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2003-019 configuration modeled in the DISIS-2016-002 models.

Figure 2-1: GEN-2003-019 Single Line Diagram (Existing Configuration)



The GEN-2003-019 Phase I Modification Request included a repowering of the 56 Vestas V-80 1.8 MW Wind Turbine Generators to a total of 49 x Vestas V-80 1.8MW + 7 x Vestas V-100 1.8 MW turbines, for a total capacity of 100.8 MW. In addition, the modification request also included updates to the collection system, generator substation transformer, and main substation transformer. The Phase II collection system, generator substation transformer, generation interconnection line, and main substation transformer were also modified with the latest project information to ensure accurate results. The major Phase I modification request changes and updates are shown in Figure 2-2 and Table 2-1 below. The Phase II updates are shown in Table 2-2.

[1] Impact Study For Generation Interconnection Request GEN-2003-019 posted in November of 2007

Figure 2-2: GEN-2003-019 Single Line Diagram (Modification Configuration)

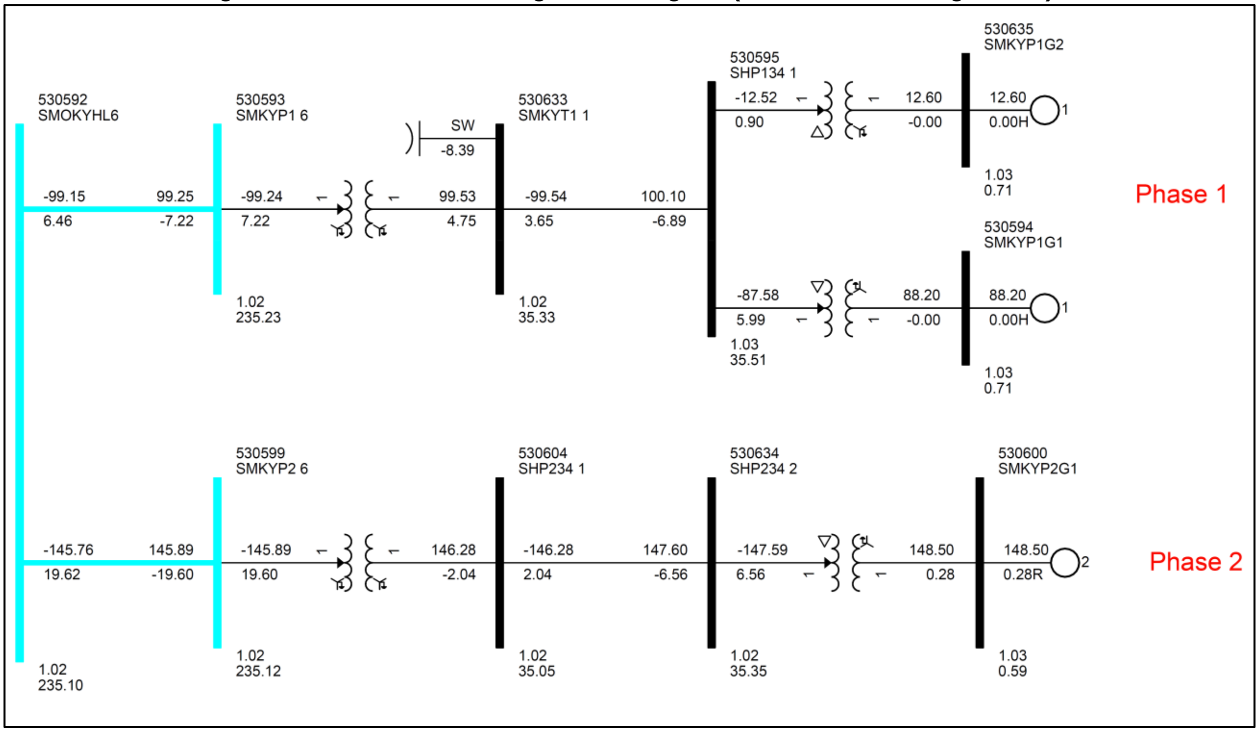


Table 2-1: GEN-2003-019 Phase I Modification Request

Facility	Existing	Modification	
Point of Interconnection	Smokey Hills 230 kV (530592)	Smokey Hills 230 kV (530592)	
Configuration/Capacity	56 x Vestas V-80 1.8MW = 100.8 MW	49 x Vestas V-80 1.8MW + 7 x Vestas V-100 1.8 MW = 100.8 MW	
Generation Interconnection Line	Length = 4.74 miles R = 0.001050 pu X = 0.007050 pu B = 0.013670 pu	Length = 4.74 miles R = 0.001050 pu X = 0.007050 pu B = 0.013670 pu	
Main Substation Transformer	X12 = 12.56%, R12 = 0.28%, X23 = 3.30%, R23 = 0.00%, X13 = 13.30%, R13 = 0.00% Winding 1-2 69 MVA, Winding 2-3 100 MVA, Rating 115 MVA	X = 8.72%, R = 0.21%, Winding 69 MVA, Rating 115 MVA	
GSU Transformer	Gen 1 Equivalent Qty: 56 X = 7.5%, R = 0.00%, Winding and Rating 117.6 MVA	Gen 1 Equivalent Qty: 49: X = 7.46%, R = 0.78%, Rating 90.7 MVA	Gen 2 Equivalent Qty: 7: X = 9.76%, R = 0.895%, Rating 16.1 MVA
Equivalent Collector Line	N/A	R = 0.005937 pu X = 0.011562 pu B = 0.041132 pu	
Generator Bus Power Factor	0.99 Leading and Lagging from the generator Additional Reactive Power Compensator at Gen Bus Modeled as: 1 x 16.78 MVAR Capacitor Bank 1 x 31.61 MVAR Capacitor Bank	Unity from the Generator N/A	
Reactive Power Devices	1 x 9 MVAR 34.5 kV Shunt Reactor 1 x 8 MVAR 34.5 kV Capacitor Bank	1 x 9 MVAR 34.5 kV Shunt Reactor 1 x 8 MVAR 34.5 kV Capacitor Bank	

Table 2-2: GEN-2003-019 Phase II Updates

Facility	Existing	Updated
Point of Interconnection	Smokey Hills 230 kV (530592)	Smokey Hills 230 kV (530592)
Configuration/Capacity	99 x GE 1.5MW = 148.5 MW	99 x GE 1.5MW = 148.5 MW
Generation Interconnection Line	Length = 2.7 miles R = 0.000600 pu X = 0.004020 pu B = 0.007790 pu	Length = 2.7 miles R = 0.000600 pu X = 0.004020 pu B = 0.007790 pu
Main Substation Transformer	X12 = 8.5%, R12 = 0.18%, X23 = 2.57%, R23 = 0.00%, X13 = 9.25%, R13 = 0.00% Winding 1-2 102.6 MVA, Winding 2-3 100 MVA, Rating 171 MVA	X = 14.49%, R = 0.32%, Winding and Rating 171 MVA
GSU Transformer	Gen 1 Equivalent Qty: 99 X = 5.7%, R = 0.76%, Winding and Rating 173.3 MVA	Gen 1 Equivalent Qty: 99 X = 5.7%, R = 0.76%, Winding and Rating 173.3 MVA
Equivalent Collector Line	N/A	R = 0.006321 pu X = 0.009117 pu B = 0.061603 pu

3.0 Reactive Power Analysis

The reactive power analysis, also known as the low-wind/no-wind condition analysis, was performed for GEN-2003-019 to determine the reactive power contribution from the project's Phase I interconnection line and collector transformer and cables during low/no wind conditions while the project is still connected to the grid and to size shunt reactors that would reduce the project reactive power contribution to the POI to approximately zero. Phase II of GEN-2003-019 was also included as it is part of the same generating facility.

3.1 Methodology and Criteria

For the GEN-2003-019 project, both Phase I and Phase II were analyzed. The entire Phase II project was taken offline and the Phase I generators and reactive power device were switched out of service while other Phase I collector system elements remained in-service. A shunt reactor was tested at the 34.5 kV collection substation bus to set the MVAr flow into the POI from Phase I to approximately zero. The same approach was done for Phase II with Phase I taken offline.

3.2 Results

The results from the reactive power analysis showed that the GEN-2003-019 project required an approximately 5.48 MVAr shunt reactor, an increase from the existing model representation which required 1.2 MVAr, for Phase I and 6.94 MVAr shunt reactor, an increase from the existing model representation which did not require reactive power, for Phase II at the respective project substations, to reduce the POI MVAr to zero. Figure 3-1 illustrates the shunt reactor sizes required to reduce the POI MVAr to approximately zero in the existing model. Figure 3-2 illustrates the shunt reactor sizes required to reduce the POI MVAr to approximately zero with the updated topology. Reactive compensation can be provided either by discrete reactive devices or by the generator itself if it possesses that capability.

Figure 3-1: Existing GEN-2003-019 Single Line Diagram (Shunt Reactor)

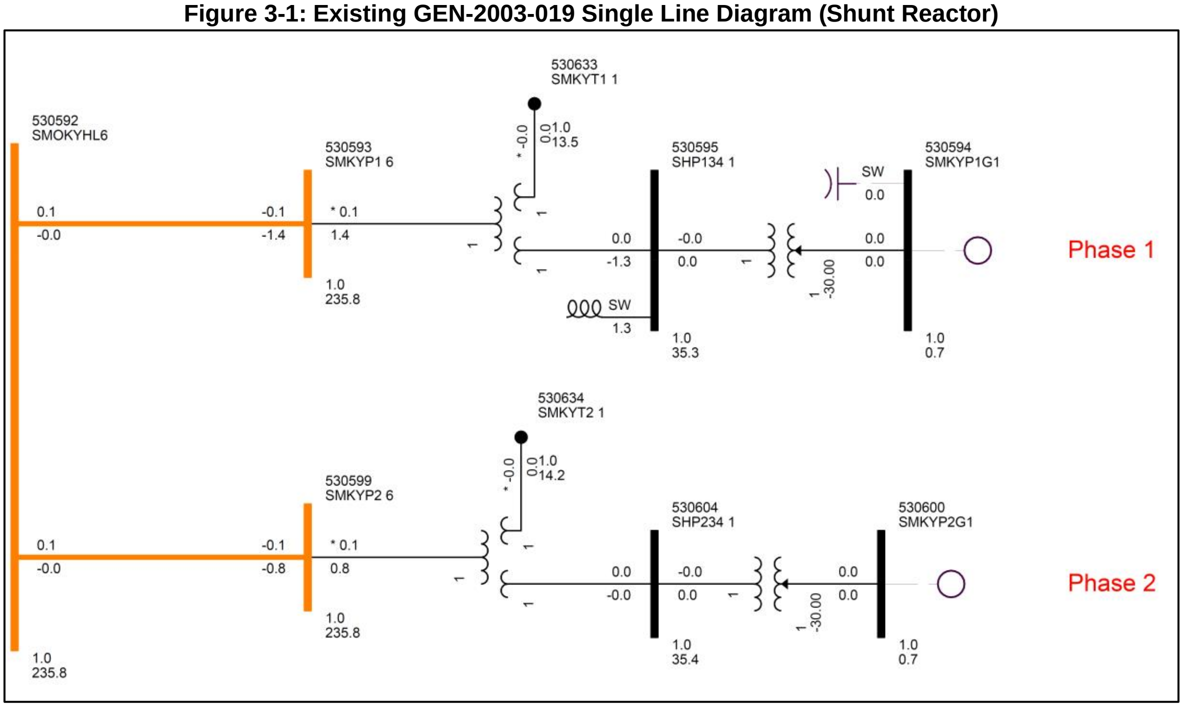


Figure 3-2: Modified GEN-2003-019 Single Line Diagram (Shunt Reactor)

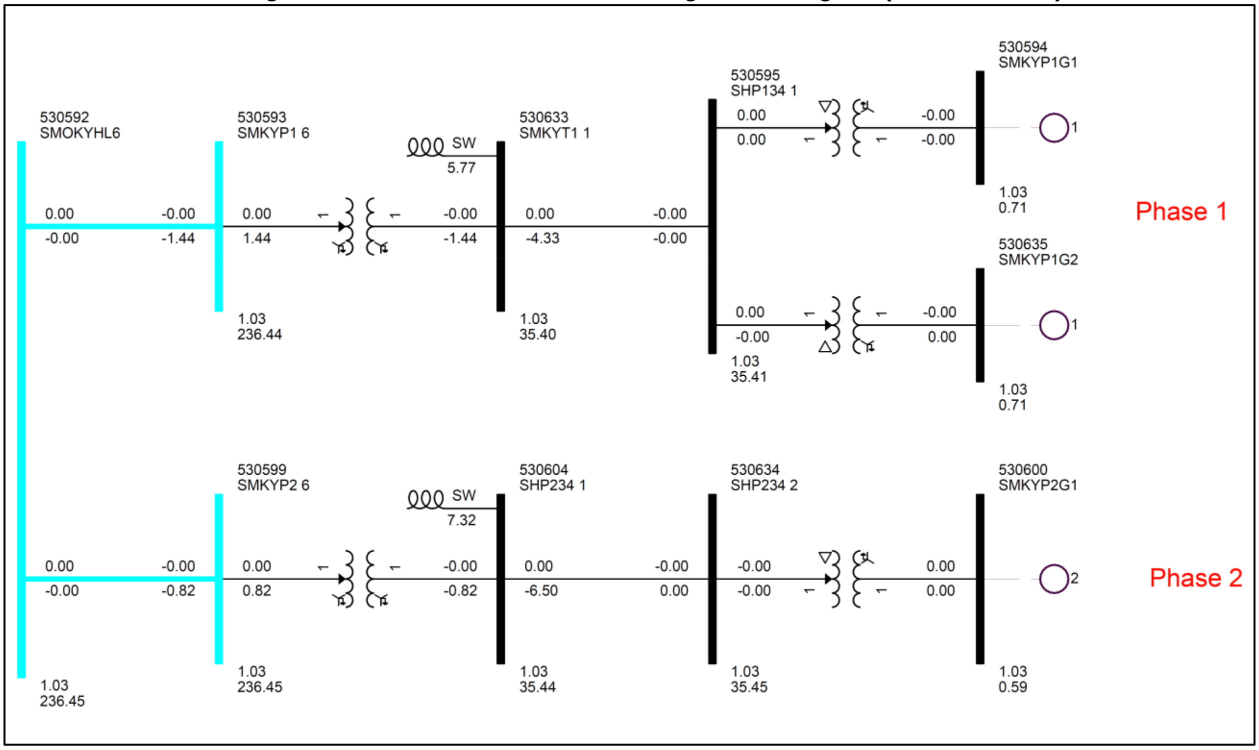


Table 3-1 shows the shunt reactor sizes determined for the three modified study models used in the assessment for both Phase I and Phase II of the GEN-2003-019 generating facility.

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

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)		
			17WP	18SP	26SP
GEN-2003-019 Phase I	530592	Smokey Hills 230 KV	5.48	5.48	5.48
GEN-2003-019 Phase II	530592	Smokey Hills 230 KV	6.94	6.94	6.94

4.0 Short Circuit Analysis

A short-circuit study was performed using the 2018SP and 2026SP models for Phase I of GEN-2003-019 with the updated topology for both Phase I and Phase II. The detailed results of the short-circuit analysis are provided in Appendix A.

4.1 Methodology

The short-circuit analysis included applying a 3-phase fault on buses up to 5 levels away from the 230 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels with and without Phase I of the project online. Phase II was left online through the analysis.

4.2 Results

The results of the short circuit analysis for the 2018SP and 2026SP models are summarized in Table 4-2 and Table 4-3 respectively. The GEN-2003-019 POI bus fault current magnitudes are provided in Table 4-1 showing a maximum fault current of 6.2 kA with Phase I online.

The maximum fault current calculated within 5 buses of the GEN-2003-019 POI was less than 27 kA for the 2018SP and 2026SP models respectively. The maximum GEN-2003-019 Phase I contribution to three-phase fault current was about 8.9% and 0.50 kA.

Table 4-1: POI Short Circuit Results

Case	Phase I GEN-OFF Current (kA)	Phase I GEN-ON Current (kA)	Max kA Change	Max %Change
2018SP	5.65	6.15	0.50	8.9%
2026SP	5.70	6.20	0.50	8.8%

Table 4-2: 2018SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
115	23.7	0.11	0.6%
230	25.0	0.50	8.9%
345	23.8	0.05	0.5%
Max	**25.0**	**0.50**	**8.9%**

Table 4-3: 2026SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
115	26.1	0.11	0.6%
230	25.0	0.50	8.8%
345	24.0	0.05	0.4%
Max	**26.1**	**0.50**	**8.8%**

5.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the turbine configuration change and other modifications to Phase I of the GEN-2003-019 project. The analysis was performed according to SPP's Disturbance Performance Requirements shown in Appendix B. The modification details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix C. The simulation plots can be found in Appendix D.

5.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested 49 Vestas V-80 1.8MW (WT2G1) and 7 Vestas V-100 1.8MW (VC20035500) turbine configuration for Phase I of the GEN-2003-019 generating facilities and 99 GE 1.5MW (GEWTG2) for Phase II. This stability analysis was performed using PTI's PSS/E version 33.7 software.

The stability models were developed using the models from DISIS-2016-002 for Group 4. The modifications requested for Phase I of the GEN-2003-019 project as well as configuration updates for Phase II were used to create modified stability models for this impact study.

The modified dynamics model data for Phase I and Phase II of GEN-2003-019 is provided in Appendix C. The modified power flow models and associated dynamics database were initialized (no-fault test) to confirm that there were no errors in the initial conditions of the system and the dynamic data.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2003-019 and both DIS-2016-002 queued and prior queued projects in Group 4. In addition, voltages of five (5) buses away from the POI of GEN-2003-019 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within this study area including 520 (AEPW), 524 (OKGE), 525 (WFEC), 526 (SPS), 531 (MIDW), 534 (SUNC), 536 (WERE), 640 (NPPD) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

5.2 Fault Definitions

Aneden simulated the faults previously simulated for GEN-2003-019 and selected additional fault events for GEN-2003-019 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 faults with stuck breakers. The simulated faults are listed and described in Table 5-1 below. These contingencies were applied to the modified 2017 Winter Peak, 2018 Summer Peak, and the 2026 Summer Peak models.

Table 5-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT01-3PH	P1	3 phase fault on the Wind Farm Gen-2003-019 Switching Station (530592) to SUMMIT (532873) 230 kV line, near Wind Farm a. Apply Fault at the Wind Farm bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault
FLT02-1PH	N/A	Single phase fault on the Wind Farm Gen-2003-019 Switching Station (530592) to SUMMIT (532873) 230 kV line, near Wind Farm a. Apply Fault at the Wind Farm bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault
FLT03-3PH	P1	3 phase fault on the Wind Farm Gen-2003-019 Switching Station (530592) to KNOLL (530558) 230 kV line, near the Wind Farm. a. Apply fault at the Wind Farm bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT04-1PH	N/A	Single phase fault on the Wind Farm Gen-2003-019 Switching Station (530592) to KNOLL (530558) 230 kV line, near the Wind Farm. a. Apply fault at the Wind Farm bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT11-3PH (17WP ONLY)	P1	3 phase fault on the SUMMIT (532773) to Jefferies Energy Center (532766) 345 kV line, near SUMMIT. a. Apply fault at the SUMMIT bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 30 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT12-1PH (17WP ONLY)	N/A	Single phase fault on the SUMMIT (532773) to Jefferies Energy Center (532766) 345 kV line, near SUMMIT. a. Apply fault at the SUMMIT bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 30 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT15-3PH	P1	3 phase fault on the KNOLL (530561) to REDLINE (530605) 115 kV line, near KNOLL. a. Apply fault at the KNOLL bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 15 cycles, and then re-close line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT16-1PH	N/A	Single phase fault on the KNOLL (530561) to REDLINE (530605) 115 kV line, near KNOLL. a. Apply fault at the KNOLL bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 15 cycles, and then re-close line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT17-3PH	P1	3 phase fault on the HAYS (530581) to VINE (530693) 115 kV line, near HAYS. a. Apply fault at the HAYS bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 15 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT18-1PH	N/A	Single phase fault on the HAYS (530581) to VINE (530693) 115 kV line, near HAYS. a. Apply fault at the HAYS bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 15 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT21-3PH	P1	3 phase fault on the KNOLL (530561) to SALINE (530551) 115 kV line, near KNOLL. a. Apply fault at the KNOLL bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 15 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT22-1PH	N/A	Single phase fault on the KNOLL (530561) to SALINE (530551) 115 kV line, near KNOLL. a. Apply fault at the KNOLL bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 15 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 5-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9001-3PH	P1	3 phase fault on KNOLL 6 (530558) to POSTROCK6 (530584) 230 kV line, near KNOLL 6. a. Apply Fault at the KNOLL 6 bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault
FLT9002-3PH	P1	3 phase fault on KNOLL 6 (530558) 230 kV to KNOLL 3 (530561) 115 kV to KNLL1 1 (530629) 11.49 kV XFMR, near KNOLL 6 230 kV. a. Apply fault at the KNOLL 6 230 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9003-3PH	P1	3 phase fault on POSTROCK6 (530584) 230 kV to POSTROCK7 (530583) 345 kV to POSTROCK1 (530673) 13.8 kV XFMR, near POSTROCK6 230 kV. a. Apply fault at the POSTROCK6 230 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9004-3PH	P1	3 phase fault on POSTROCK6 (530584) to S Hays6 (530582) 230 kV line, near POSTROCK6. a. Apply Fault at the POSTROCK6 bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault
FLT9005-3PH	P1	3 phase fault on POSTROCK6 (530584) to Buckeye_230 (530702) 230 kV line, near POSTROCK6. a. Apply Fault at the POSTROCK6 bus. b. Clear fault after 5 cycles by tripping the faulted line. Trip generators BUCKE_WTG (530705), BUCKW_WTG (530708) and G16-160-GEN1 (588451). c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault
FLT9006-3PH	P1	3 phase fault on POSTROCK7 (530583) to G13-010-TAP (562334) 345 kV line, near POSTROCK7. a. Apply Fault at the POSTROCK7 bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault
FLT9007-3PH	P1	3 phase fault on POSTROCK7 (530583) to G16-050-TAP (560082) 345 kV line, near POSTROCK7. a. Apply Fault at the POSTROCK7 bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault
FLT9008-3PH	P1	3 phase fault on SUMMIT 6 (532873) to UNIONRG6 (532874) 230 kV line, near SUMMIT 6. a. Apply Fault at the SUMMIT 6 bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault
FLT9009-3PH	P1	3 phase fault on SUMMIT 6 (532873) 230 kV to SUMMIT 3 (533381) 115 kV to SUMIT2 1 (532896) 13.8 kV XFMR, near SUMMIT 6 230 kV. a. Apply fault at the SUMMIT 6 230 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9010-3PH	P1	3 phase fault on SUMMIT 6 (532873) 230 kV to SUMMIT 7 (532773) 345 kV to SUMMIT 1 (532813) 14.4 kV XFMR, near SUMMIT 6 230 kV. a. Apply fault at the SUMMIT 6 230 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9011-3PH	P1	3 phase fault on SUMMIT 6 (532873) to Emcpher6 (532872) 230 kV line, near SUMMIT 6. a. Apply Fault at the SUMMIT 6 bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault

Table 5-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9012-3PH	P1	3 phase fault on UNIONRG6 (532874) 230 kV to UNIONRG3 (533359) 115 kV to UNIONRG1 (532817) 13.2 kV XFMR, near UNIONRG6 230 kV. a. Apply fault at the UNIONRG6 230 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9013-3PH	P1	3 phase fault on UNIONRG6 (532874) to GEN-2015-069 (585070) 230 kV line, near UNIONRG6. a. Apply Fault at the UNIONRG6 bus. b. Clear fault after 5 cycles by tripping the faulted line. Trip generator G15-069-GEN1 (585073). c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault
FLT9014-3PH	P1	3 phase fault on UNIONRG6 (532874) to MORRIS 6 (532863) 230 kV line, near UNIONRG6. a. Apply Fault at the UNIONRG6 bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault
FLT9015-3PH	P1	3 phase fault on SUMMIT 7 (532773) to ELMCREEK7 (539805) 345 kV line, near SUMMIT 7. a. Apply Fault at the SUMMIT 7 bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault
FLT9016-3PH (18SP and 26SP Only)	P1	3 phase fault on SUMMIT 7 (532773) to GEARY 7 (532767) 345 kV line, near SUMMIT 7. a. Apply Fault at the SUMMIT 7 bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault
FLT9017-3PH	P1	3 phase fault on SUMMIT 7 (532773) to G16-112-TAP (587894) 345 kV line, near SUMMIT 7. a. Apply Fault at the SUMMIT 7 bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault
FLT9018-3PH	P1	3 phase fault on ELMCREEK7 (539805) 345 kV to ELMCREEK6 (539639) 230 kV to ELMCREEK1 (539806) 13.8 kV XFMR, near ELMCREEK7 345kV. a. Apply fault at the ELMCREEK7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9019-3PH	P1	3 phase fault on ELMCREEK6 (539639) to NMANHT6 (532865) 230 kV line, near ELMCREEK6. a. Apply Fault at the ELMCREEK6 bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault
FLT9020-3PH	P1	3 phase fault on ELMCREEK6 (539639) to MRWYP (539637) 230 kV line, near ELMCREEK6. a. Apply Fault at the ELMCREEK6 bus. b. Clear fault after 5 cycles by tripping the faulted line. Trip generators MRWY-WG1 (599025) and MRWY-WG2 (599027). c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault
FLT9021-3PH	P1	3 phase fault on ELMCREEK6 (539639) to CONCRD6 (539658) 230 kV line, near ELMCREEK6. a. Apply Fault at the ELMCREEK6 bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault
FLT9022-3PH	P1	3 phase fault on JEC N 7 (532766) to MORRIS 7 (532770) 345 kV line, near JEC N 7. a. Apply Fault at the JEC N 7 bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault

Table 5-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9023-3PH (18SP and 26SP Only)	P1	3 phase fault on GEARY 7 (532767) 345 kV to GEARY 3 (533336) 115 kV to GEARY 1X1 (532834) 13.8 kV XFMR, near GEARY 7 345 kV. a. Apply fault at the GEARY 7 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9024-3PH	P1	3 phase fault on EMCPHER6 (532872) 230 kV to EMCPHER3 (533417) 115 kV to EMCPHER1 (532894) 13.8 kV XFMR, near GEARY 7 345 kV. a. Apply fault at the EMCPHER6 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9025-3PH	P1	3 phase fault on EMCPHER6 (532872) to CIRCLE 6 (532871) 230 kV line, near EMCPHER6. a. Apply Fault at the EMCPHER6 bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault
FLT9026-3PH	P1	3 phase fault on G16-112-TAP (587894) to G16-111-TAP (587884) 345 kV line, near G16-112-TAP. a. Apply Fault at the G16-112-TAP bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault
FLT9027-3PH	P1	3 phase fault on G16-111-TAP (587884) to RENO 7 (532771) 345 kV line, near G16-111-TAP. a. Apply Fault at the G16-111-TAP bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault
FLT9028-3PH	P1	3 phase fault on the KNOLL 3 (530561) to OGALATP3 (530677) 115 kV line, near KNOLL 3. a. Apply fault at the KNOLL 3 bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 15 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9029-3PH	P1	3 phase fault on the KNOLL 3 (530561) to GMEC 3 (530676) 115 kV line, near KNOLL 3. a. Apply fault at the KNOLL 3 bus. b. Clear fault after 5 cycles by tripping the faulted line. Trip generators GMECG1 1 (530674) and GMECG2 1 (530675). c. Wait 15 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9030-3PH	P1	3 phase fault on the KNOLL 3 (530561) to N HAYS3 (530581) 115 kV line, near KNOLL 3. a. Apply fault at the KNOLL 3 bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 15 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9031-3PH	P1	3 phase fault on the SUMMIT 3 (533381) to SO GATE3 (533379) 115 kV line, near SUMMIT 3. a. Apply fault at the SUMMIT 3 bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 15 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9032-3PH	P1	3 phase fault on the SUMMIT 3 (533381) to EXIDE J3 (533368) 115 kV line, near SUMMIT 3. a. Apply fault at the SUMMIT 3 bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 15 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9033-3PH	P1	3 phase fault on the SUMMIT 3 (533381) to NORTHVW3 (533371) 115 kV line, near SUMMIT 3. a. Apply fault at the SUMMIT 3 bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 15 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9034-3PH (18SP and 26SP Only)	P1	3 phase fault on GEARY 7 (532767) to JEC N 7 (532766) 345 kV line, near GEARY 7. a. Apply Fault at the GEARY 7 bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault

Table 5-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9008-PO1	P6	**Prior Outage of the Wind Farm Gen-2003-019 Switching Station (530592) to KNOLL (530558) 230 kV line.** 3 phase fault on SUMMIT 6 (532873) to UNIONRG6 (532874) 230 kV line, near SUMMIT 6. a. Apply Fault at the SUMMIT 6 bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault
FLT9009-PO1	P6	**Prior Outage of the Wind Farm Gen-2003-019 Switching Station (530592) to KNOLL (530558) 230 kV line.** 3 phase fault on SUMMIT 6 (532873) 230 kV to SUMMIT 3 (533381) 115 kV to SUMIT2 1 (532896) 13.8 kV XFMR, near SUMMIT 6 230 kV. a. Apply fault at the SUMMIT 6 230 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9010-PO1	P6	**Prior Outage of the Wind Farm Gen-2003-019 Switching Station (530592) to KNOLL (530558) 230 kV line.** 3 phase fault on SUMMIT 6 (532873) 230 kV to SUMMIT 7 (532773) 345 kV to SUMMIT 1 (532813) 14.4 kV XFMR, near SUMMIT 6 230 kV. a. Apply fault at the SUMMIT 6 230 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9011-PO1	P6	**Prior Outage of the Wind Farm Gen-2003-019 Switching Station (530592) to KNOLL (530558) 230 kV line.** 3 phase fault on SUMMIT 6 (532873) to Emcpher6 (532872) 230 kV line, near SUMMIT 6. a. Apply Fault at the SUMMIT 6 bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault
FLT9001-PO2	P6	**Prior Outage of the Wind Farm Gen-2003-019 Switching Station (530592) to SUMMIT (532873) 230 kV line.** 3 phase fault on KNOLL 6 (530558) to POSTROCK6 (530584) 230 kV line, near KNOLL 6. a. Apply Fault at the KNOLL 6 bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault
FLT9002-PO2	P6	**Prior Outage of the Wind Farm Gen-2003-019 Switching Station (530592) to SUMMIT (532873) 230 kV line.** 3 phase fault on KNOLL 6 (530558) 230 kV to KNOLL 3 (530561) 115 kV to KNLL1 1 (530629) 11.49 kV XFMR, near KNOLL 6 230 kV. a. Apply fault at the KNOLL 6 230 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT1001-SB	P4	**Stuck Breaker at KNOLL 6 (530558)** a. Apply single phase fault at KNOLL 6 230 kV bus. b. Clear fault after 16 cycles and trip the following elements c. Drop the bus KNOLL (530558).
FLT1002-SB	P4	**Stuck Breaker at SUMMIT 6 (532873)** a. Apply single phase fault at SUMMIT 6 230 kV bus. b. Clear fault after 16 cycles and trip the following elements c. SUMMIT 6 (532873) to UNIONRG6 (532874) 230 kV CKT 1 line d. SUMMIT 6 (532873) 230 kV to SUMMIT 7 (532773) 345 kV to SUMMIT 1 (532813) 14.4 kV XFMR
FLT1003-SB	P4	**Stuck Breaker at SUMMIT 6 (532873)** a. Apply single phase fault at SUMMIT 6 230 kV bus. b. Clear fault after 16 cycles and trip the following elements c. SUMMIT 6 (532873) to UNIONRG6 (532874) 230 kV CKT 1 line d. SUMMIT 6 (532873) to EMCPHER6 (532872) 230 kV line
FLT1004-SB	P4	**Stuck Breaker at SUMMIT 6 (532873)** a. Apply single phase fault at SUMMIT 6 230 kV bus. b. Clear fault after 16 cycles and trip the following elements c. SUMMIT 6 (532873) 230 kV to SUMMIT 3 (533381) 115 kV to SUMIT2 1 (532896) 13.8 kV XFMR d. SUMMIT 6 (532873) 230 kV to SUMMIT 7 (532773) 345 kV to SUMMIT 1 (532813) 14.4 kV XFMR

Table 5-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT1005-SB	P4	**Stuck Breaker at SUMMIT 6 (532873)** a. Apply single phase fault at SUMMIT 6 230 kV bus. b. Clear fault after 16 cycles and trip the following elements c. SUMMIT 6 (532873) to SMOKYHL6 (530592) 230 kV line. d. SUMMIT 6 (532873) 230 kV to SUMMIT 7 (532773) 345 kV to SUMMIT 1 (532813) 14.4 kV XFMR
FLT1006-SB	P4	**Stuck Breaker at SUMMIT 6 (532873)** a. Apply single phase fault at SUMMIT 6 230 kV bus. b. Clear fault after 16 cycles and trip the following elements c. SUMMIT 6 (532873) to SUMMIT 6 (532873) 230 kV to SUMMIT 3 (533381) 115 kV to SUMIT3 1 (532897) 13.8 kV XFMR d. SUMMIT 6 (532873) to EMCPHER6 (532872) 230 kV line
FLT1007-SB	P4	**Stuck Breaker at SUMMIT 6 (532873)** a. Apply single phase fault at SUMMIT 6 230 kV bus. b. Clear fault after 16 cycles and trip the following elements c. SUMMIT 6 (532873) to SUMMIT 6 (532873) 230 kV to SUMMIT 3 (533381) 115 kV to SUMIT3 1 (532897) 13.8 kV XFMR d. SUMMIT 6 (532873) to SMOKYHL6 (530592) 230 kV line.

5.3 Results

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

Table 5-2: GEN-2003-019 Phase I Dynamic Stability Results

Fault ID	2017WP			2018SP			2026SP		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable
FLT01-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-1PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-1PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT11-3PH (17WP ONLY)	Pass	Pass	Stable						
FLT12-1PH (17WP ONLY)	Pass	Pass	Stable						
FLT15-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT16-1PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT17-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT18-1PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT21-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT22-1PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 5-2 continued

Fault ID	2017WP			2018SP			2026SP		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH (18SP and 26SP Only)				Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH (18SP and 26SP Only)				Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9027-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9028-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9029-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9030-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9031-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9032-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9033-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9034-3PH (18SP and 26SP Only)				Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

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

6.0 Conclusions

The Interconnection Customer for GEN-2003-019 requested a Modification Request Impact Study to assess the impact of the turbine and facility changes to Phase I of the configuration with a total of 49 x Vestas V-80 1.8MW + 7 x Vestas V-100 1.8MW wind turbines for a total capacity of 100.8 MW. In addition, the Phase I modification request included updates to the collection system, generator substation transformer, and main substation transformer. The Phase II collection system, generator substation transformer, generation interconnection line, and main substation transformer were also updated with the latest project information to ensure accurate results.

A power factor analysis was not performed as there was no change in the point of interconnection for GEN-2003-019.

The results of the reactive power analysis, also known as the low-wind/no-wind condition analysis, showed that Phase I of the GEN-2003-019 project may require a 5.48 MVAr shunt reactor on the 34.5 kV bus of the Phase I project substation which is an increase from the existing model representation which required 1.2 MVAr. Phase II of the GEN-2003-019 project may require a 6.94 MVAr shunt reactor on the 34.5 kV bus of the Phase II project substation, an increase from the existing model representation which did not require reactive power. A shunt reactor is needed to reduce the reactive power transfer at the POI to approximately zero during low/no wind conditions while Phase I and Phase II of the generation interconnection project remains connected to the grid.

The results from the short circuit analysis with the updated topology showed that the maximum Phase I GEN-2003-019 contribution to three-phase fault currents in the immediate systems at or near GEN-2003-019 was not greater than 0.50 kA for the 2018SP and 2026SP cases. All three-phase fault current levels within 5 buses of the POI with the GEN-2003-019 Phase I and Phase II generators online were below 27 kA for the 2018SP models and 2026SP models.

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