GEN-2013-002 & GEN-2013-019

Impact Restudy for Generator Modification

Published February 2019

By Generator Interconnection

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
2/13/2019	Generator Interconnection		Initial Posting

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EXECUTIVE SUMMARY

The GEN-2013-002 and GEN-2013-019 Interconnection Customer has requested a modification to its Interconnection Request. This system impact restudy was performed to determine the effects of changing wind turbine generators from the previously studied 54 Siemens 2.3 MW wind turbine generators (for a total capacity of 124.2 MW) to 54 GE 2.3 MW wind turbine generators (for a total capacity of 124.2 MW). The Point of Interconnection (POI) for this request has also changed from a tap into the Lincoln Electric System (LES) Sheldon to SW 7th Bennet 115 kV transmission line to the 115 kV bus inside the Nebraska Public Power District (NPPD) Monolith 115 kV substation.

The dynamic stability portion of this study was performed by Aneden Consulting, while the steady-state power flow analysis portion was performed by SPP to determine whether the request for modification is considered Material. The consultant's dynamic stability study report is included in Appendix A.

The stability analysis for this restudy showed that no other stability problems were found during the summer and the winter peak conditions as a result of changing to the GE 2.3 MW wind turbine generators. Additionally, the project wind farm was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A. The steady-state power flow analysis demonstrated that no additional constraints are identified due to the change in the project POI, and no other interconnection requests' costs or timelines are affected by the modification.

With the assumptions outlined in this report and with all the required network upgrades in place, GEN-2013-002 and GEN-2013-019 with 54 GE 2.3 MW wind turbine generators should be able to interconnect reliably to the SPP transmission grid. This restudy confirms that the requested modification in wind turbine generators is not considered Material.

A low-wind/no-wind condition analysis was performed for this modification request. To prevent reactive power injection into the transmission system during low/no wind operation, the Interconnection Customer will be required to install approximately 6.5 MVAr of shunt reactors to be located on the 115 kV bus or install and utilize an equivalent means of compensating for the injection of reactive power into the transmission system at the Point of Interconnection.

It should be noted that this study analyzed the requested modification to change generator technology and layout. This study analyzed many of the most probable contingencies, but it is not an all-inclusive list and cannot account for every operational situation. It is likely that 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.

POWER FLOW ANALYSIS

POWER FLOW ANALYSIS METHODOLOGY

The ACCC function of PSS/E is used to simulate single element and special (i.e., breaker-to-breaker, multi-element, etc.) contingencies in portions or all of the modeled control areas of SPP as well as control areas external to SPP. A power flow analysis is conducted for the Interconnection Customer's facility using modified versions of the year 1 winter peak season, the year 2 spring, year 2 summer peak season, year 5 summer and winter peak seasons, year 5 light load season, and year 10 summer peak seasonal models.

Network constraints are found by using PSS/E AC Contingency Calculation (ACCC) analysis with PSS/E MUST First Contingency Incremental Transfer Capability (FCITC) analysis on the entire cluster grouping dispatched at the various levels previously described.

For ERIS, thermal overloads are determined for system intact (n-0) greater than 100% of Rate A - normal and for contingency (n-n) greater than 100% of Rate B – emergency conditions.

The overloads are then screened to determine which interconnection requests have at least

- 3% Distribution Factor (DF) for system intact conditions (n-0),
- 20% DF upon outage-based conditions (n-n),
- or 3% DF on contingent elements that resulted in a non-converged solution.

Interconnection Requests that requested NRIS are also studied in a separate NRIS analysis to determine if any constraint measured greater than or equal to a 3% DF.

After all thermal overload and voltage support mitigations are determined; a full ACCC analysis is then performed to determine voltage constraints. The following voltage performance guidelines are used in accordance with the Transmission Owner local planning criteria.

SPP voltage criteria is applicable to all SPP facilities 69 kV and greater in the absence of more stringent criteria:

System Intact	Contingency
0.95 – 1.05 per unit	0.90 – 1.05 per unit

Areas and specific buses having more-stringent voltage criteria:

Areas/Facilities	System Intact	Contingency
AEPW – all buses EMDE High Voltage	0.95 – 1.05 per unit	0.92 – 1.05 per unit
WERE Low Voltage	0.95 – 1.05 per unit	0.93 – 1.05 per unit
WERE High Voltage	0.95 – 1.05 per unit	0.95 – 1.05 per unit
TUCO 230 kV Bus #525830	0.925 – 1.05 per unit	0.925 – 1.05 per unit
Wolf Creek 345 kV Bus #532797	0.985 – 1.03 per unit	0.985 – 1.03 per unit
FCS Bus #646251	1.001 – 1.047 per unit	1.001 – 1.047 per unit

First-Tier External Areas facilities 115 kV and greater.

Area	System Intact	Contingency
EES-EAI LAGN EES AMMO CLEC LAFA LEPA XEL MP SMMPA GRE OTP ALTW MEC MDU DPC ALTE	0.95 – 1.05 per unit	0.90 – 1.05 per unit
OTP-H (115kV+)	0.97 – 1.05 per unit	0.92 – 1.10 per unit
SPC	0.95 – 1.05 per unit	0.95 – 1.05 per unit

The constraints identified through the voltage scan are screened for the following for each interconnection request. 1) 3% DF on the contingent element and 2) 2% change in pu voltage. In certain conditions, engineering judgement was used to determine whether or not a generator had impacts to voltage constraints.

For this modification study, the BC (Base Case) was taken from the DISIS-2016-002 Scenario 0 Group 09 ERIS and NRIS models with the GEN-2013-002 and GEN-2013-019 requests at the previous POI. The TC (Transfer Case) included the POI modification for the GEN-2013-002 and GEN-2013-019 requests to the Monolith 115 kV substation.

POWER FLOW RESULTS

CLUSTER SCENARIO

The Cluster Scenario considers the Base Case as well as all Interconnection Requests in the DISIS Study Queue and all generating facilities (and with respect to (3) below, any identified Network Upgrades associated with such higher-queued interconnection) that, on the date the DISIS is commenced:

1. are directly connected to the Transmission System;
2. are interconnection to Affected Systems and may have an impact on the Interconnection Request;
3. have a pending higher-queued Interconnection Request to interconnect to the Transmission System; and
4. have no Interconnection Queue Position but have executed a GIA or requested that an unexecuted GIA be filed with FERC.

CLUSTER GROUP 9 (NEBRASKA AREA)

The table shown on the next page depicts the constraints that were identified as a result of the modification of the GEN-2013-002 and GEN-2013-019 interconnection requests. A comparison of the BC and TC loadings on constraints that show up in the DISIS-2016-002 TC Group 09 ERIS and NRIS models shows there is no change between the steady-state loadings pre-modification and post-modification. The Transfer Distribution Factor's (TDF's) for projects in Group 09 have not been affected by the modification by GEN-2013-002 and GEN-2013-019. The steady-state power flow analysis demonstrates that there are no additional voltage or thermal constraints.

Table 1 Group 9 Cluster Constraints

SOLUTION	GROUP	SCENARIO	SEASON	SOURCE	DIRECTION	MONITORED ELEMENT	RATEA (MVA)	RATEB(MVA)	TDF	TC%LOADING (% MVA)	CONTINGENCY
There were no additional constraints identified in this cluster group.											

APPENDIX A: STABILITY STUDY REPORT

Aneden Consulting report follows.

Submitted to

Southwest Power Pool

SPP Southwest Power Pool

Report On

GEN-2013-002 & GEN-2013-019
Modification Request Impact Study

Revision R1

Date of Submittal
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anedenconsulting.com

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APPENDICES

Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2013-002 and GEN-2013-019, active generation interconnection requests with a common point of interconnection (POI) on the Sheldon to SW 7th & Bennet 115 kV transmission line.

The GEN-2013-002 and GEN-2013-019 projects were proposed to interconnect in the Nebraska Public Power District (NPPD) control area with a combined capacity of 124.2 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2013-002 and GEN-2013-019 point of interconnection change to the Monolith 115 kV substation and turbine configuration change to a total of 22 x GE 2.3 MW and 32 x GE 2.3 MW for GEN-2013-002 and GEN-2013-019 respectively, for a total capacity of 124.2 MW. Both projects were modeled as a single equivalent generator. In addition, the modification request included changes to the generation interconnection line, collection system and the main substation transformer. The modification request changes are shown in Table ES-2 below.

Table ES-1: Existing GEN-2013-002 & GEN-2013-019 Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2013-002	50.6	22 x Siemens 2.3MW	Sheldon to SW 7th Bennet 115 kV Line (560746)
GEN-2013-019	73.6	32 x Siemens 2.3 MW	Sheldon to SW 7th Bennet 115 kV Line (560746)

Table ES-2: GEN-2013-002 & GEN-2013-019 Modification Request

Facility	Existing	Modification Request
Point of Interconnection	Tap on Sheldon to SW 7th Bennet 115 kV Line (560746)	Monolith 115 kV Substation (640591)
Configuration/Capacity	22 x Siemens 108m VS 2.3 MW 32 x Siemens 108m VS 2.3 MW	22 x GE 2.3 MW 32 x GE 2.3 MW
Generation Interconnection Line(s)	Length = 1.05 miles R = 0.000700 pu X = 0.005300 pu B = 0.000900 pu *Zero impedance line is included in original case	Length = 3.00 miles R = 0.002650 X = 0.016020 B = 0.002390 *Zero impedance line is included in new case
Main Substation Transformer	T1: Z = 8.5%, Rating 55 MVA T2: Z = 8.0%, Rating 75 MVA	T1: Z = 8.0%, Rating 140 MVA
Equivalent Collector Line 1	R = 0.027860 pu X = 0.034740 pu B = 0.026680 pu	R = 0.006773 X = 0.010646 B = 0.062520
Equivalent Collector Line 2	R = 0.028910 pu X = 0.034140 pu B = 0.053810 pu	N/A

GEN-2013-002 and GEN-2013-019 were originally studied as part of Group 9 in the DISIS-2013-001 and DISIS-2013-002. Aneden performed power factor analysis, reactive power analysis, short circuit analysis and dynamic stability analysis using the modification request data based on the DISIS-2016-001 ReStudy #1 Group 9 study models listed below:

1. 2016 Winter Peak (2016WP)
2. 2017 Summer Peak (2017SP)
3. 2025 Summer Peak (2025SP)
4. 2016 GGS Winter Peak Case (2016WP_GGS)
5. 2017 GGS Summer Peak Case (2017SP_GGS)
6. 2025 GGS Summer Peak Case (2025SP_GGS)

All analyses were performed using the PTI PSS/E version 32 software and the results are summarized below.

The power factor analysis was performed for all N-1 contingencies performed in the stability analysis using all six models. The minimum leading power factors (generation facility absorbing reactive power from the network) were found to be 0.877 pf (68.21 MVAr) in the 2017 summer peak case and 0.805 pf (91.43 MVAr) in the 2017 summer peak. The GEN-2013-002 and GEN-2013-019 project turbines have +/-0.90 pf capability. Per SPP Tariff requirements, the Generating Facilities will be required to meet the standard 95% power factor requirement at the Point of Interconnection. The customer may be required to add capacitor and/or reactor banks depending upon its final collector system design.

The results of the reactive power analysis, also known as the low-wind/no-wind condition analysis, performed using all three models showed that the combined GEN-2013-002 and GEN-2013-019 project may require a 6.5 MVAr shunt reactor on the 115 kV bus of the project substation. The shunt reactor is needed to reduce the reactive power transfer at the POI to approximately zero during low/no wind conditions while the generation interconnection project remains connected to the grid.

The results from short circuit analysis showed that the maximum change in the fault currents in the immediate systems at or near GEN-2013-002 and GEN-2013-019 was approximately 1.6 kA. All three-phase current levels with the GEN-2013-002 and GEN-2013-019 generator online were below 43 kA for the 2017SP models and 44 kA for the 2025SP models.

The dynamic stability analysis was performed using the six models 2016 Winter Peak, 2017 Summer Peak, 2025 Summer Peak, 2016 Winter Peak GGS, 2017 Summer Peak GGS, and 2025 Summer Peak GGS. Up to 101 contingencies were simulated, which included three-phase faults, three phase faults on prior outage cases, and single-line-to-ground faults and stuck breakers faults.

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

The results of this Study show that the GEN-2013-002 and GEN-2013-019 Modification Request does not constitute a material modification.

1.0 Introduction

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2013-002 and GEN-2013-019, two active generation interconnection requests with a common point of interconnection (POI) on the Sheldon to SW 7th & Bennet 115 kV transmission line.

The GEN-2013-002 and GEN-2013-019 projects were proposed to interconnect in the Nebraska Public Power District (NPPD) control area with a combined capacity of 124.2 MW as shown in Table 1-1 below. Details of the modification request as provided in Section 2.0 below.

Table 1-1: Existing GEN-2013-002 & GEN-2013-019 Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2013-002	50.6	22 x Siemens 2.3MW	Tap on Sheldon to SW 7th Bennet 115 kV Line (560746)
GEN-2013-019	73.6	32 x Siemens 2.3 MW	Tap on Sheldon to SW 7th Bennet 115 kV Line (560746)

1.1 Scope

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

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

Aneden performed a power factor analysis, reactive power analysis, short circuit analysis and dynamic stability analysis using a set of modified study models developed using the modification request data and the six DISIS-2016-001 ReStudy #1 study models:

1. 2016 Winter Peak (2016WP),
2. 2017 Summer Peak (2017SP),
3. 2025 Summer Peak (2025SP),
4. 2016 GGS Winter Peak Case (2016WP_GGS),
5. 2017 GGS Summer Peak Case (2017SP_GGS), and
6. 2025 GGS Summer Peak Case (2025SP_GGS).

All analyses were performed using the PTI PSS/E version 32 software. The results of each analysis are presented in the following sections.

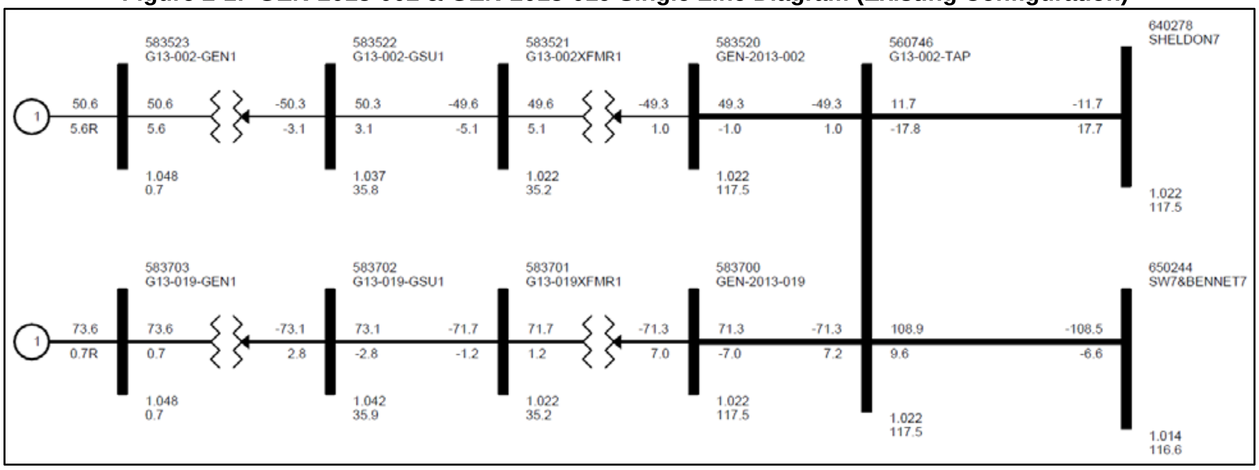
1.2 Study Limitations

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

Figure 2-1 shows the power flow model single line diagram for the existing GEN-2013-002 and GEN-2013-019 configurations. GEN-2013-002 and GEN-2013-019 were originally studied as part of Group 9 in the DISIS-2013-001 and DISIS-2013-002 studies respectively.

Figure 2-1: GEN-2013-002 & GEN-2013-019 Single Line Diagram (Existing Configuration)



The GEN-2013-002 and GEN-2013-019 Modification Request included a point of interconnection change to the Monolith 115 kV substation and turbine configuration change to a total of 22 x GE 2.3 MW and 32 x GE 2.3 MW for GEN-2013-002 and GEN-2013-019 respectively, a combined capacity of 124.2 MW. In addition, the modification request also included changes to the collection system, the main substation transformer and the generation interconnection line. The major modification request changes are shown in Figure 2-2 and Table 2-1 below. The two projects were modeled as a single equivalent generator in this Study.

Figure 2-2: GEN-2013-002 & GEN-2013-019 Single Line Diagram (New Configuration)

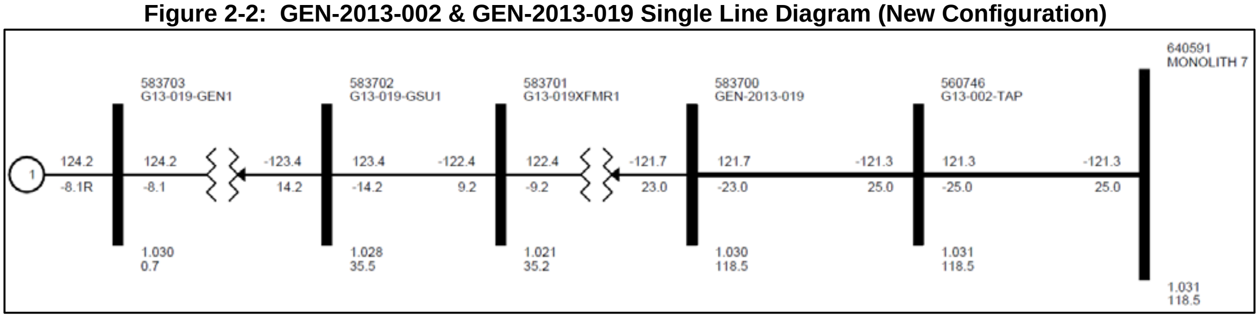


Table 2-1: GEN-2013-002 & GEN-2013-019 Modification Request

Facility	Existing	Modification Request
Point of Interconnection	Tap on Sheldon to SW 7th Bennet 115 kV Line (560746)	Monolith 115 kV Substation (640591)
Configuration/Capacity	22 x Siemens 2.3 MW 32 x Siemens 2.3 MW	22 x GE 2.3 MW 32 x GE 2.3 MW
Generation Interconnection Line(s)	Length = 1.05 miles R = 0.000700 pu X = 0.005300 pu B = 0.000900 pu *Zero impedance line is included in original case	Length = 3.00 miles R = 0.002650 X = 0.016020 B = 0.002390 *Zero impedance line is included in new case
Main Substation Transformer	T1: Z = 8.5%, Rating 55 MVA T2: Z = 8.0%, Rating 75 MVA	T1: Z = 8.0%, Rating 140 MVA
Equivalent Collector Line 1	R = 0.027860 pu X = 0.034740 pu B = 0.026680 pu	R = 0.006773 X = 0.010646 B = 0.062520
Equivalent Collector Line 2	R = 0.028910 pu X = 0.034140 pu B = 0.053810 pu	N/A

3.0 Power Factor Requirement

The power factor analysis was performed using the modified study models created using the DISIS 2016-001 Restudy #1 2016WP, 2017SP, 2025SP and the GGS 2016WP, 2017SP, and 2025SP models. The methodology and results of the power factor analysis are provided in Appendix A.

3.1 Methodology and Criteria

The GEN-2013-002 and GEN-2013-019 projects were turned off for the power factor analysis. The interconnection generator was replaced with a generator modeled at the high voltage bus of the collector substation transformer. The replacement generator was modeled to reflect the real power (MW) output of the interconnection request generator. This replacement generator was set to maintain a voltage schedule at the point of interconnection consistent with the voltage schedule in each of the modified study models or 1.0 pu voltage, whichever was higher. Table 3-1 shows the POI bus voltages used in the analysis. Table 3-2 shows the POI bus voltages for the GGS models used in the analysis. The replacement generator's reactive power capability was set to +/-9999 MVAr to find the required power factor.

Table 3-1: Base Case GEN-2013-002 & GEN-2013-019 POI Bus Voltages

Machine	PF Capability	POI Bus Number	Initial POI Voltage (pu)		
			16WP	17SP	25SP
GEN-2013-002 & GEN-2013-019	+/- .90	640591	1.032	1.033	1.031

Table 3-2: GGS Model Base Case GEN-2013-002 & GEN-20103-019 POI Bus Voltages

Machine	PF Capability	POI Bus Number	Initial POI Voltage (pu) for GGS Models		
			16WP_GGS	17SP_GGS	25SP_GGS
GEN-2013-002 & GEN-2013-019	+/- .90	640591	1.032	1.031	1.032

The reactive power output of the replacement generator was captured for all the N-1 three phase contingencies simulated and the resulting leading and lagging power factors were computed. The results of the power factor analysis are presented in Appendix A.

3.2 Results

The power factor analysis results for the modified GEN-2013-002 and GEN-2013-019 facilities for the N-1 three phase contingencies are presented in Appendix A.

The lowest leading power factor (generation facility absorbing reactive power from the network) were found to be 0.877 pf (68.21 MVAr) in the 2017 summer peak case and 0.805 pf (91.43 MVAr) in the 2017 summer peak GGS. Per SPP Tariff requirements, the Generating Facilities will be required to meet the standard 95% power factor (leading and lagging) requirement at the Point of Interconnection. The customer may be required to add capacitor and/or reactor banks depending upon its final collector system design.

4.0 Reactive Power Analysis

The reactive power analysis, also known as the low-wind/no-wind condition analysis, was performed for GEN-2013-002 and GEN-2013-019 to determine the reactive power contribution from the project's 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.

4.1 Methodology and Criteria

For the GEN-2013-002 and GEN-2013-019 combined project, the generator was switched out of service while other collector system elements remained in-service. A shunt reactor was tested at the collection substation 115 kV bus to set the MVAr flow into the POI to approximately zero.

4.2 Results

The results from the reactive power analysis showed that the GEN-2013-002 and GEN-2013-019 projects required approximately 6.5 MVAr shunt reactance at the high side of the project substation, to reduce the POI MVAr to zero. This represents the contributions from the project collection system. Figure 4-1 illustrates the shunt reactor size required to reduce the POI voltage to approximately zero. Reactive compensation can be provided either by discrete reactive devices or by the generator itself if it possesses that capability.

Figure 4-1: GEN-2013-002 & GEN-2013-019 Single Line Diagram (Shunt Reactor)

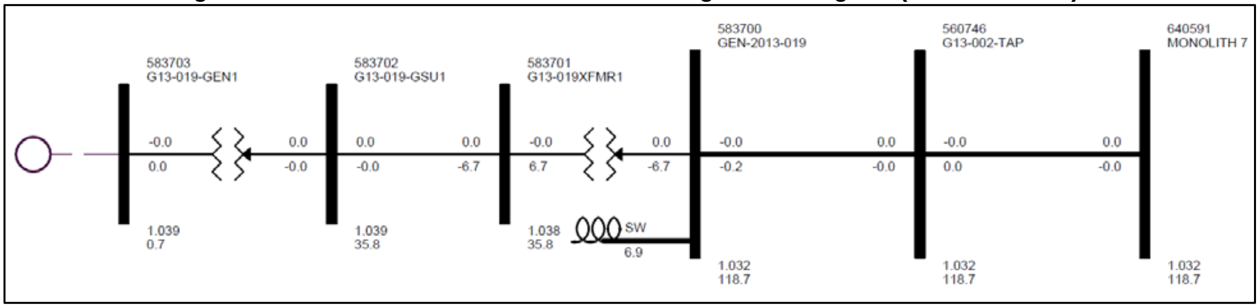


Table 4-1 shows the shunt reactor size determined for the three study models used in the assessment.

Table 4-1: Shunt Reactor Size for Low Wind Study

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)		
			16WP	17SP	25SP
GEN-2013-002 & GEN-2013-019	640591	MONOLITH 7	6.5	6.5	6.5

5.0 Short Circuit Analysis

A short-circuit study was performed using the power flow models for the 2017SP and 2025SP models and the 2017SP GGS and 2025SP GGS models for GEN-2013-002 and GEN-2013-019. The detail 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 115 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 the project online.

5.2 Results

The results of the short circuit analysis for the 2017SP and 2025SP models are summarized in Table 5-1 and Table 5-2 respectively. The maximum increase in fault current was about 1.6096 kA. The maximum fault current calculated within 5 buses with GEN-2013-002 and GEN-2013-019 was less than 43 kA for the 2017SP model and 44 kA for the 2025SP model.

Table 5-1: 2017SP Short Circuit Results

Bus Distance	Max. Change (kA)	Max %Change
0	1.6096	4.06%
1	1.4168	3.45%
2	0.3224	1.46%
3	0.1724	0.77%
4	0.1355	0.68%
5	0.1395	0.48%

Table 5-2: 2025SP Short Circuit Results

Bus Distance	Max. Change (kA)	Max %Change
0	1.6035	3.91%
1	1.4063	3.31%
2	0.3069	1.36%
3	0.1619	0.70%
4	0.1239	0.62%
5	0.1235	0.41%

The results of the short circuit analysis for the 2017SP and 2025SP GGS models are summarized in Table 5-3 and Table 5-4Table 5-2 respectively. The maximum increase in fault current was about 1.6080 kA. The maximum fault current calculated within 5 buses with GEN-2013-002 and GEN-2013-019 was less than 42 kA for the 2017SP GGS model and 44 kA for the 2025SP GGS model.

Table 5-3: 2017SP GGS Short Circuit Results

Bus Distance	Max. Change (kA)	Max %Change
0	1.6080	4.12%
1	1.4221	3.51%
2	0.3214	1.47%
3	0.1756	0.77%
4	0.1374	0.68%
5	0.1404	0.49%

Table 5-4: 2025SP GGS Short Circuit Results

Bus Distance	Max. Change (kA)	Max %Change
0	1.6018	3.99%
1	1.4129	3.38%
2	0.3052	1.37%
3	0.1638	0.70%
4	0.1226	0.61%
5	0.1229	0.42%

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the point of interconnection change, turbine configuration change and other modifications to the GEN-2013-002 and GEN-2013-019 projects. The analysis was performed according to SPP's Disturbance Performance Requirements shown in Appendix C. The modification details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix D. The simulation plots can be found in Appendix E.

6.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested 22 x GE 2.3 MW and 32 x GE 2.3 MW turbine configuration for the GEN-2013-002 and GEN-2013-019 generating facilities. This stability analysis was performed using PTI's PSS/E version 32 software.

The stability models were developed using the models from the DISIS-2016-001 ReStudy #1 Group 9 including network upgrades identified in that restudy. The modifications requested to project GEN-2013-002 and GEN-2013-019 were used to create modified stability models for this impact study.

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. The modified dynamics model data for the DISIS-2013-002 Group 9 request, GEN-2013-002 and GEN-2013-019 is provided in Appendix D.

During the fault simulations, the active power (PELEC), reactive power (QELEC) and terminal voltage (ETERM) were monitored for GEN-2013-002 and GEN-2013-019 and other equally and prior queued projects in Group 9. In addition, voltages of five (5) buses away from the POI of GEN-2013-002 and GEN-2013-019 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within this study area including 534 (SUNC), 536 (WERE), 540 (GMO), 541 (KCPL), 635 (MEC), 640 (NPPD), 645 (OPPD), 650 (LES), 652 (WAPA) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

6.2 Fault Definitions

Aneden selected the fault events simulated specifically for GEN-2013-002 and GEN-2013-019 in the DISIS-2013-002 Group 9 study and included additional faults based on the new point of interconnection. The new set of faults were simulated using the modified study models. The fault events include three phase faults with reclosing, stuck breaker, and prior outage events. Single-line-to-ground (SLG) fault impedance values were determined by applying a fault on the base case large enough to produce a 0.6 pu voltage value on the faulted bus. This SLG fault impedance value was then used for the SLG faults.

The simulated faults are listed and described in Table 6-1 below. These contingencies were applied to the modified 2016 Winter Peak, 2017 Summer Peak, and the 2025 Summer Peak models (including the GGS models).

Table 6-1: Fault Definitions

Fault ID	Fault Descriptions
FLT03-3PH	3 phase fault on SHELDON (640278) 115kV to BPS SUB7 (640088) 115kV near SHELDON.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT04-3PH	3 phase fault on SHELDON (640278) 115kV to CRETE7 (640153) 115kV near SHELDON.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT05-3PH	3 phase fault on SHELDON (640278) 115kV to CLATONA7 (640111) 115kV near SHELDON
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT07-3PH	3 phase fault on Folsom & Pleasant Hill (650242) 115kV to 20th & Pioneer (650238) 115kV near Folsom.
	a. Apply fault at Folsom 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT08-3PH	3 phase fault on Folsom & Pleasant Hill (650242) 115kV to ROKEBY (650290) 115kV near Folsom.
	a. Apply fault at Folsom 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT09-3PH	3 phase fault on BEATRCE (640076) 115kV to BPS Sub (640088) 115kV near BEATRCE.
	a. Apply fault at BEATRCE 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT17-3PH	3 phase fault on MOORE (640277) 345kV to MCCOOL (640271) 345kV near MOORE.
	a. Apply fault at MOORE 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT19-3PH	3 phase fault on MOORE (640277) 345kV to NW68HOLDRG3 (650114) 345kV near MOORE.
	a. Apply fault at MOORE 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT20-3PH	3 phase fault on MOORE (640277) 345kV to 103&ROKEBY (650189) 345kV near MOORE.
	a. Apply fault at MOORE 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT54-3PH	3 phase fault on NW68HOLDRG3 (650114) 345kV to NW68HOLDRG7 (650214) 115kV to NW68HOL1 (650314) 13.8kV transformer at the 345kV bus.
	a. Apply fault at NW68HOLDRG3 345kV bus.
	b. Clear fault after 4.5 cycles by tripping the transformer.
FLT55-3PH	3 phase fault on the MOORE (640277) 345kV to SHELDON (640278) 115kV to MOORE (640280) 13.8kV transformer at the 345kV bus.
	a. Apply fault at MOORE 345kV bus.
	b. Clear fault after 4.5 cycles by tripping the transformer.
FLT67-3PH	Prior outage of Fairport (300039) - St Joe (541199) 345 kV with a 3-phase fault near Cooper (640139) on Cooper (640139) - St Joe (541199) 345 kV.
	Prior outage of Fairport (300039) to St. Joe (541199) 345kV line (network back at steady state)
	a. Apply 3-phase fault at Cooper (640139) 345kV
	b. Run for 4.5 cycles
	c. Clear fault
	d. Trip line from Cooper (640139) to G10-056-Tap (560663) 345kV
FLT72-1PH	Sheldon Stuck Breaker
	a. Apply single phase fault at the Sheldon (640278) 115kV bus on the Sheldon- Folsom & pleasant Hill (650242) 115kV line Ckt 1.
	b. wait 16 cycles, and then drop Sheldon (640278) 115kV- Firth (640171) 115kV
	c. Trip Sheldon to Folsom & pleasant Hill 115kV and remove the fault.

Table 6-1 continued

Fault ID	Fault Descriptions
FLT9001-3PH	3 phase fault on the SHELDON 7 (640278) 115kV to MOORE 3 (640277) 345kV to MOORE 9 (640280) 13.8kV transformer at the 115kV bus.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer.
FLT9002-3PH	3 phase fault on SHELDON 7 (640278) 115kV to FOLSM&PHIL7 (650242) 115kV near SHELDON.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT9003-3PH	3 phase fault on the SHELDON 7 (640278) 115kV to SHELDON 9 (640279) 34.5kV to SHELDON T4 9 (643104) 13.8kV transformer at the 115kV bus.
	a. Apply fault at SHELDON 7 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer.
FLT9004-3PH	3 phase fault on SHELDON (640278) 115kV to SHELDN1G (640019) 13.8kV transformer at the 115kV bus.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer, tripping generator at bus 640019.
FLT9005-3PH	3 phase fault on SHELDON (640278) 115kV to SHELDN2G (640020) 13.8kV transformer at the 115kV bus.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer, tripping generator at 640020.
FLT9006-3PH	3 phase fault on SHELDON (640278) 115kV to HALLAM3G (640021) 13.8kV transformer at the 115kV bus.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer, tripping generator at bus 640021.
FLT9007-3PH	3 phase fault on SHELDON7 (640278) 115kV to SW7&BENNET7 (650244) 115kV near SHELDON7.
	a. Apply fault at SHELDON7 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT9008-3PH	3 phase fault on FOLSM&PHIL 7 (650242) 115kV to SW7&BENNET7 (650244) 115kV near FOLSM&PHIL 7.
	a. Apply fault at FOLSM&PHIL7 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT9009-3PH	3 phase fault on MONOLITH 7 (640591) 115kV to SHELDON 7 (640278) 115kV Ckt 1 near MONOLITH.
	a. Apply fault at MONOLITH 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT9010-3PH	3 phase fault on MONOLITH 7 (640591) 115kV to MONOLITH 9 (640593) 34.5kV transformer at the 115kV bus.
	a. Apply fault at MONOLITH 7 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer.
FLT9011-3PH	3 phase fault on MONOLITH 7 (640591) 115kV to FIRTH 7 (640171) 115kV near MONOLITH.
	a. Apply fault at MONOLITH 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT9012-3PH	3 phase fault on MONOLITH 7 (640591) 115kV to MONOLITH 3 (640590) 345kV to MONOLITHT1 9 (640596) 13.8kV transformer at the 115kV bus.
	a. Apply fault at MONOLITH 7 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer.
FLT9013-3PH	3 phase fault on COOPER 3 (640139) 345kV to COOPER1G (640009) 22kV transformer at the 345kV bus.
	a. Apply fault at COOPER 345kV bus.
	b. Clear fault after 4.5 cycles by tripping the transformer, tripping generator at bus 640009.
FLT9014-3PH	3 phase fault on MOORE (640277) 345kV to G15-088-TAP (560062) 345kV near MOORE.
	a. Apply fault at MOORE 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9015-3PH	3 phase fault on FIRTH 7 (640171) 115kV to FIRTH 9 (640172) 34.5kV to FIRTHT1 9 (643057) 13.8kV transformer at the 115kV bus.
	a. Apply fault at FIRTH 7 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer.

Table 6-1 continued

Fault ID	Fault Descriptions
FLT9016-3PH	3 phase fault on MONOLITH 3 (640590) 345kV to MOORE 3 (640277) 345kV near MONOLITH.
	a. Apply fault at MONOLITH 3 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9017-3PH	3 phase fault on MONOLITH 3 (640590) 345kV to COOPER 3 (640139) 345kV near MONOLITH.
	a. Apply fault at MONOLITH 3 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9018-3PH	3 phase fault on BPS SUB7 (640088) 115kV to BPS GT2G (640023) 13.8kV transformer at the 115kV bus.
	a. Apply fault at BPS SUB7 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer, tripping generator at bus 640023.
FLT9019-3PH	3 phase fault on BPS SUB7 (640088) 115kV to BPS ST3G (640024) 13.8kV transformer at the 115kV bus.
	a. Apply fault at BPS SUB7 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer, tripping generator at bus 640024.
FLT9020-3PH	3 phase fault on BPS SUB7 (640088) 115kV to BPS GT1G (640022) 13.8kV transformer at the 115kV bus.
	a. Apply fault at BPS SUB7 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer, tripping generator at bus 640022.
FLT9021-3PH	3 phase fault on BPS SUB7 (640088) 115kV to CLATONA7 (640111) 115kV near BPS SUB7.
	a. Apply fault at BPS SUB7 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT9022-3PH	3 phase fault on BPS SUB7 (640088) 115kV to BEATRCE7 (640076) 115kV near BPS SUB7 Ckt 1.
	a. Apply fault at BPS SUB7 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT9023-3PH	3 phase fault on FIRTH 7 (640171) 115kV to STERLNG7 (640362) 115kV near FIRTH 7.
	a. Apply fault at FIRTH 7 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT9024-3PH	3 phase fault on CRETE (640153) 115kV to FRIEND (640174) 115kV near CRETE.
	a. Apply fault at CRETE 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT9025-3PH	3 phase fault on COOPER 3 (640139) 345kV to 7FAIRPT (300039) 345kV near COOPER.
	a. Apply fault at COOPER 3 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9026-3PH	3 phase fault on COOPER 3 (640139) 345kV to ST JOE 3 (541199) 345kV near COOPER.
	a. Apply fault at COOPER 3 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9027-3PH	3 phase fault on COOPER 3 (640139) 345kV to S3458 3 (645458) 345kV near COOPER.
	a. Apply fault at COOPER 3 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9028-3PH	3 phase fault on COOPER 3 (640139) 345kV to ATCHSNT3 (635017) 345kV near COOPER.
	a. Apply fault at COOPER 3 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9029-3PH	3 phase fault on COOPER 3 (640139) 345kV to COOPER 5 (640140) 161kV to COOPER T2 9 (640142) 13.8kV transformer at the 345kV bus.
	a. Apply fault at COOPER 345kV bus.
	b. Clear fault after 4.5 cycles by tripping the transformer.
FLT9030-3PH	3 phase fault on SW7&BENNET7 (650244) 115kV to ATC40&ROKEBY 7 (650250) 115kV near SW7&BENNET7.
	a. Apply fault at SW7&BENNET7 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.

Table 6-1 continued

Fault ID	Fault Descriptions
FLT9031-3PH	3 phase fault on ST JOE (541199) 345kV to EASTOWN7 (541400) 345kV near ST JOE.
	a. Apply fault at ST JOE 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9032-3PH	3 phase fault on ST JOE (541199) 345kV to 7FAIRPT (300039) 345kV near ST JOE.
	a. Apply fault at ST JOE 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9033-3PH	3 phase fault on ST JOE (541199) 345kV to NASHUA 7 (542980) 345kV near ST JOE.
	a. Apply fault at ST JOE 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9034-3PH	3 phase fault on ST JOE (541199) 345kV to ST JOE 5 (541253) 161kV to ST JOE (541370) 13.8kV transformer at the 345kV bus.
	a. Apply fault at ST JOE 345kV bus.
	b. Clear fault after 4.5 cycles by tripping the transformer.
FLT9035-3PH	3 phase fault on ATCHSNT3 (635017) 345kV to BOONVIL3 (635630) 345kV near ATCHSNT3.
	a. Apply fault at ATCHSNT3 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9036-3PH	3 phase fault on ATCHSNT3 (635017) 345kV to ATCHSN 3 (635018) 345kV near ATCHSNT3.
	a. Apply fault at ATCHSNT3 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line, tripping generator at 635020.
FLT9037-3PH	3 phase fault on NW68HOLDRG3 (650114) 345kV to WAGENER (650185) 345kV near NW68HOLDRG3.
	a. Apply fault at NW68HOLDRG3 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9038-3PH	3 phase fault on 103&ROKEBY3 (650189) 345kV to WAGENER (650185) 345kV near 103&ROKEBY3.
	a. Apply fault at 103&ROKEBY3 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9039-3PH	3 phase fault on 7FAIRPT (300039) 345kV to 5FAIRPT (300076) 161kV transformer at the 345kV bus.
	a. Apply fault at 7FAIRPT 345kV bus.
	b. Clear fault after 4.5 cycles by tripping the transformer.
FLT9040-3PH	3 phase fault on MCCOOL (640271) 345kV to GR ISLD3 (652571) 345kV near MCCOOL.
	a. Apply fault at MCCOOL 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9041-3PH	3 phase fault on MCCOOL (640271) 345kV to MCCOOL (640272) 115kV to MCCOOL19 (640274) 13.8kV transformer at the 345kV bus.
	a. Apply fault at MCCOOL 345kV bus.
	b. Clear fault after 4.5 cycles by tripping the transformer.
FLT9042-3PH	3 phase fault on G15-088-TAP (560062) 345kV to GEN-2015-088 (585240) 345kV near G15-088-TAP.
	a. Apply fault at G15-088-TAP 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line, tripping generator at bus 585243.
FLT9043-3PH	3 phase fault on G15-088-TAP (560062) 345kV to PAULINE3 (640312) 345kV near G15-088-TAP.
	a. Apply fault at G15-088-TAP 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9044-3PH	3 phase fault on G14-021-TAP (560009) 345kV to GEN-2014-021 (583910) 345kV near G14-021-TAP.
	a. Apply fault at G14-021-TAP 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line, tripping generator at bus 583913, tripping generator at bus 583917
FLT9045-3PH	3 phase fault on NW68HOLDRG3 (650114) 345kV to COLMB (640125) 345kV near NW68HOLDRG3.
	a. Apply fault at NW68HOLDRG3 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.

Table 6-1 continued

Fault ID	Fault Descriptions
FLT9046-3PH	3 phase fault on S3458 (645458) 345kV to 103&ROKEBY3 (650189) 345kV near S3458.
	a. Apply fault at S3458 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9047-3PH	3 phase fault on S3458 (645458) 345kV to NEBCTY1G (645011) 23kV at the 345kV bus.
	a. Apply fault at S3458 345kV bus.
	b. Clear fault after 4.5 cycles by tripping the transformer, tripping generator at bus 645011.
FLT9048-3PH	3 phase fault on S3458 (645458) 345kV to NEBCTY1G (645012) 23kV at the 345kV bus.
	a. Apply fault at S3458 345kV bus.
	b. Clear fault after 4.5 cycles by tripping the transformer, tripping generator at bus 645012.
FLT9049-3PH	3 phase fault on S3458 (645458) 345kV to S3456 (645456) 345kV near S3458.
	a. Apply fault at S3458 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9050-3PH	3 phase fault on S3458 (645458) 345kV to S3740 (645740) 345kV near S3458.
	a. Apply fault at S3458 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9051-3PH	3 phase fault on S3458 (645458) 345kV to G14-021-TAP (560009) 345kV near S3458.
	a. Apply fault at S3458 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9052-3PH	3 phase fault on G14-021-TAP (560009) 345kV to MULLNCR7 (541197) 345kV near G14-021-TAP.
	a. Apply fault at G14-021-TAP 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9015-PO1	Prior Outage of the MONOLITH (640591) 115kV to SHELDON7 (640278) 115kV. 3 phase fault on FIRTH 7 (640171) 115kV to FIRTH 9 (640172) 34.5kV to FIRTHT1 9 (643057) 13.8kV transformer at the 115kV bus.
	a. Apply fault at FIRTH 7 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer.
FLT9023-PO1	Prior Outage of the MONOLITH (640591) 115kV to SHELDON7 (640278) 115kV. 3 phase fault on FIRTH 7 (640171) 115kV to STERLNG7 (640362) 115kV near FIRTH 7.
	a. Apply fault at FIRTH 7 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT9016-PO1	Prior Outage of the MONOLITH (640591) 115kV to SHELDON7 (640278) 115kV. 3 phase fault on MONOLITH 3 (640590) 345kV to MOORE 3 (640277) 345kV near MONOLITH.
	a. Apply fault at MONOLITH 3 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9017-PO1	Prior Outage of the MONOLITH (640591) 115kV to SHELDON7 (640278) 115kV. 3 phase fault on MONOLITH 3 (640590) 345kV to COOPER 3 (640139) 345kV near MONOLITH.
	a. Apply fault at MONOLITH 3 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT03-PO2	Prior Outage of the MONOLITH (640591) 115kV to FIRTH (640171) 115kV. 3 phase fault on SHELDON (640278) 115kV to BPS SUB7 (640088) 115kV near SHELDON.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT04-PO2	Prior Outage of the MONOLITH (640591) 115kV to FIRTH (640171) 115kV. 3 phase fault on SHELDON (640278) 115kV to CRETE7 (640153) 115kV near SHELDON.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT05-PO2	Prior Outage of the MONOLITH (640591) 115kV to FIRTH (640171) 115kV. 3 phase fault on SHELDON (640278) 115kV to CLATONA7 (640111) 115kV near SHELDON
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.

Table 6-1 continued

Fault ID	Fault Descriptions
FLT9001-PO2	Prior Outage of the MONOLITH (640591) 115kV to FIRTH (640171) 115kV. 3 phase fault on the SHELDON 7 (640278) 115kV to MOORE 3 (640277) 345kV to MOORE 9 (640280) 13.8kV transformer at the 115kV bus.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer.
FLT9002-PO2	Prior Outage of the MONOLITH (640591) 115kV to FIRTH (640171) 115kV. 3 phase fault on SHELDON 7 (640278) 115kV to FOLSM&PHIL7 (650242) 115kV near SHELDON.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT9003-PO2	Prior Outage of the MONOLITH (640591) 115kV to FIRTH (640171) 115kV. 3 phase fault on the SHELDON 7 (640278) 115kV to SHELDON 9 (640279) 34.5kV to SHELDON T4 9 (643104) 13.8kV transformer at the 115kV bus.
	a. Apply fault at SHELDON 7 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer.
FLT9004-PO2	Prior Outage of the MONOLITH (640591) 115kV to FIRTH (640171) 115kV. 3 phase fault on SHELDON (640278) 115kV to SHELDN1G (640019) 13.8kV transformer at the 115kV bus.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer, tripping generator at bus 640019.
FLT9005-PO2	Prior Outage of the MONOLITH (640591) 115kV to FIRTH (640171) 115kV. 3 phase fault on SHELDON (640278) 115kV to SHELDN2G (640020) 13.8kV transformer at the 115kV bus.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer, tripping generator at 640020.
FLT9006-PO2	Prior Outage of the MONOLITH (640591) 115kV to FIRTH (640171) 115kV. 3 phase fault on SHELDON (640278) 115kV to HALLAM3G (640021) 13.8kV transformer at the 115kV bus.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer, tripping generator at bus 640021.
FLT9016-PO2	Prior Outage of the MONOLITH (640591) 115kV to FIRTH (640171) 115kV. 3 phase fault on MONOLITH 3 (640590) 345kV to MOORE 3 (640277) 345kV near MONOLITH.
	a. Apply fault at MONOLITH 3 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT9017-PO2	Prior Outage of the MONOLITH (640591) 115kV to FIRTH (640171) 115kV. 3 phase fault on MONOLITH 3 (640590) 345kV to COOPER 3 (640139) 345kV near MONOLITH.
	a. Apply fault at MONOLITH 3 345kV bus.
	b. Clear fault after 4.5 cycles by tripping faulted line.
FLT03-PO3	Prior Outage of the MONOLITH 7 (640591) 115kV to MONOLITH 3 (640590) 345kV to MONOLITHT1 9 (640596) 13.8kV transformer. 3 phase fault on SHELDON (640278) 115kV to BPS SUB7 (640088) 115kV near SHELDON.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT04-PO3	Prior Outage of the MONOLITH 7 (640591) 115kV to MONOLITH 3 (640590) 345kV to MONOLITHT1 9 (640596) 13.8kV transformer. 3 phase fault on SHELDON (640278) 115kV to CRETE7 (640153) 115kV near SHELDON.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT05-PO3	Prior Outage of the MONOLITH 7 (640591) 115kV to MONOLITH 3 (640590) 345kV to MONOLITHT1 9 (640596) 13.8kV transformer. 3 phase fault on SHELDON (640278) 115kV to CLATONA7 (640111) 115kV near SHELDON
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.

Table 6-1 continued

Fault ID	Fault Descriptions
FLT9001-PO3	Prior Outage of the MONOLITH 7 (640591) 115kV to MONOLITH 3 (640590) 345kV to MONOLITHT1 9 (640596) 13.8kV transformer. 3 phase fault on the SHELDON 7 (640278) 115kV to MOORE 3 (640277) 345kV to MOORE 9 (640280) 13.8kV transformer at the 115kV bus.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer.
FLT9002-PO3	Prior Outage of the MONOLITH 7 (640591) 115kV to MONOLITH 3 (640590) 345kV to MONOLITHT1 9 (640596) 13.8kV transformer. 3 phase fault on SHELDON 7 (640278) 115kV to FOLSM&PHIL7 (650242) 115kV near SHELDON.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT9003-PO3	Prior Outage of the MONOLITH 7 (640591) 115kV to MONOLITH 3 (640590) 345kV to MONOLITHT1 9 (640596) 13.8kV transformer. 3 phase fault on the SHELDON 7 (640278) 115kV to SHELDON 9 (640279) 34.5kV to SHELDON T4 9 (643104) 13.8kV transformer at the 115kV bus.
	a. Apply fault at SHELDON 7 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer.
FLT9004-PO3	Prior Outage of the MONOLITH 7 (640591) 115kV to MONOLITH 3 (640590) 345kV to MONOLITHT1 9 (640596) 13.8kV transformer. 3 phase fault on SHELDON (640278) 115kV to SHELDN1G (640019) 13.8kV transformer at the 115kV bus.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer, tripping generator at bus 640019.
FLT9005-PO3	Prior Outage of the MONOLITH 7 (640591) 115kV to MONOLITH 3 (640590) 345kV to MONOLITHT1 9 (640596) 13.8kV transformer. 3 phase fault on SHELDON (640278) 115kV to SHELDN2G (640020) 13.8kV transformer at the 115kV bus.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer, tripping generator at 640020.
FLT9006-PO3	Prior Outage of the MONOLITH 7 (640591) 115kV to MONOLITH 3 (640590) 345kV to MONOLITHT1 9 (640596) 13.8kV transformer. 3 phase fault on SHELDON (640278) 115kV to HALLAM3G (640021) 13.8kV transformer at the 115kV bus.
	a. Apply fault at SHELDON 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer, tripping generator at bus 640021.
FLT9015-PO3	Prior Outage of the MONOLITH 7 (640591) 115kV to MONOLITH 3 (640590) 345kV to MONOLITHT1 9 (640596) 13.8kV transformer. 3 phase fault on FIRTH 7 (640171) 115kV to FIRTH 9 (640172) 34.5kV to FIRTHT1 9 (643057) 13.8kV transformer at the 115kV bus.
	a. Apply fault at FIRTH 7 115kV bus.
	b. Clear fault after 6.5 cycles by tripping the transformer.
FLT9023-PO3	Prior Outage of the MONOLITH 7 (640591) 115kV to MONOLITH 3 (640590) 345kV to MONOLITHT1 9 (640596) 13.8kV transformer. 3 phase fault on FIRTH 7 (640171) 115kV to STERLNG7 (640362) 115kV near FIRTH 7.
	a. Apply fault at FIRTH 7 115kV bus.
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT9026-PO4	Prior outage of Fairport (300039) - St Joe (541199) 345 kV. 3-phase fault near Cooper (640139) on Cooper (640139) - St Joe (541199) 345 kV.
	a. Apply 3-phase fault at Cooper (640139) 345kV
	b. Clear fault after 6.5 cycles by tripping faulted line.
FLT9100-SB	SHELDON7 115kV Stuck Breaker
	a. Apply single phase fault at the SHELDON7 (640278) 115kV bus on the SHELDON7 (640278) - MONOLITH (640591) 115kV line.
	b. Wait 16 cycles, and then trip SHELDON7 (640278) - MONOLITH (640591) 115kV line, branch 1.
	c. Trip SHELDON7 (640278) - MONOLITH (640591) 115kV line, branch 2 and remove the fault.

Table 6-1 continued

Fault ID	Fault Descriptions
FLT9200-SB	FIRTH 115kV Stuck Breaker
	a. Apply single phase fault at the FIRTH (640171) 115kV bus on the FIRTH (640171) - MONOLITH (640591) 115kV line.
	b. Wait 16 cycles, and then trip FIRTH (640171) - MONOLITH (640591) 115kV line.
	c. Trip FIRTH (640171) - STERLNG7 (640362) 115kV line and remove the fault.
FLT9300-SB	MONOLITH3 345kV Stuck Breaker
	a. Apply single phase fault at the MONOLITH 3 (640590) 345kV bus on the MONOLITH 3 (640590) - MONOLITH (640591) 115kV - MONOLITHT1 (640596) 13.8kV transformer.
	b. Wait 16 cycles, and then trip the MONOLITH 3 (640590) - MONOLITH (640591) 115kV - MONOLITHT1 (640596) 13.8kV transformer.
	c. Trip the MONOLITH 3 (640590) - COOPER 3 (640139) 345kV line and remove the fault.
FLT9301-SB	MONOLITH3 345kV Stuck Breaker
	a. Apply single phase fault at the MONOLITH 3 (640590) 345kV bus on the MONOLITH 3 (640590) - MONOLITH (640591) 115kV - MONOLITHT1 (640596) 13.8kV transformer.
	b. Wait 16 cycles, and then trip the MONOLITH 3 (640590) - MONOLITH (640591) 115kV - MONOLITHT1 (640596) 13.8kV transformer.
	c. Trip the MONOLITH 3 (640590) - MOORE 3 (640277) 345kV line and remove the fault.
FLT9400-SB	MONOLITH 7 115kV Stuck Breaker
	a. Apply single phase fault at the MONOLITH 7 (640591) 115kV bus on the MONOLITH 3 (640590) - MONOLITH (640591) 115kV - MONOLITHT1 (640596) 13.8kV transformer.
	b. Wait 16 cycles, and then trip the MONOLITH 3 (640590) - MONOLITH (640591) 115kV - MONOLITHT1 (640596) 13.8kV transformer.
	c. Trip the MONOLITH 7 (640591) - FIRTH 7 (640171) 115kV line and remove the fault.
FLT9401-SB	MONOLITH 7 115kV Stuck Breaker
	a. Apply single phase fault at the MONOLITH 7 (640591) 115kV bus on the MONOLITH 3 (640590) - MONOLITH (640591) 115kV - MONOLITHT1 (640596) 13.8kV transformer.
	b. Wait 16 cycles, and then trip the MONOLITH 3 (640590) - MONOLITH (640591) 115kV - MONOLITHT1 (640596) 13.8kV transformer.
	c. Trip the MONOLITH 7 (640591) - SHELDON7 (640278) 115kV line and remove the fault.
FLT9402-SB	MONOLITH 7 115kV Stuck Breaker
	a. Apply single phase fault at the MONOLITH 7 (640591) 115kV bus on the MONOLITH 3 (640590) - MONOLITH (640591) 115kV - MONOLITHT1 (640596) 13.8kV transformer.
	b. Wait 16 cycles, and then trip the MONOLITH 3 (640590) - MONOLITH (640591) 115kV - MONOLITHT1 (640596) 13.8kV transformer.
	c. Trip the MONOLITH 7 (640591) 115kV - MONOLITH 9 (640593) 34.5kV transformer and remove the fault.
FLT9403-SB	MONOLITH 7 115kV Stuck Breaker
	a. Apply single phase fault at the MONOLITH 7 (640591) 115kV bus on the MONOLITH 7 (640591) 115kV - MONOLITH 9 (640593) 34.5kV transformer.
	b. Wait 16 cycles, and then trip the MONOLITH 7 (640591) 115kV - MONOLITH 9 (640593) 34.5kV transformer.
	c. Trip the MONOLITH 7 (640591) - FIRTH 7 (640171) 115kV line and remove the fault.
FLT9404-SB	MONOLITH 7 115kV Stuck Breaker
	a. Apply single phase fault at the MONOLITH 7 (640591) 115kV bus on the MONOLITH 7 (640591) 115kV - MONOLITH 9 (640593) 34.5kV transformer.
	b. Wait 16 cycles, and then trip the MONOLITH 7 (640591) 115kV - MONOLITH 9 (640593) 34.5kV transformer.
	c. Trip the MONOLITH 7 (640591) - SHELDON7 (640278) 115kV line and remove the fault.

6.3 Results

There were no damping or voltage recovery violations observed during the simulated faults. Table 6-2 shows the results of the fault events simulated for each of the models. The associated stability plots are provided in Appendix E. Additionally, the project wind farm 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.

Table 6-2: GEN-2013-002 & GEN-2013-019 Dynamic Stability Results

Fault ID	G09			G09 GGS		
	16WP	17SP	25SP	16WP	17SP	25SP
FLT03-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT04-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT05-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT07-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT08-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT09-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT17-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT19-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT20-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT54-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT55-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT67-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9001-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9002-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9003-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9004-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9005-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9006-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9007-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9008-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9009-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9010-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9011-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9012-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9013-3PH	Stable*	Stable*	Stable*	Stable*	Stable*	Stable*
FLT9014-3PH	Stable	Stable	Stable	Stable	Stable	Stable

Table 6-2 continued

Fault ID	G09			G09 GGS		
	16WP	17SP	25SP	16WP	17SP	25SP
FLT9015-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9016-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9017-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9018-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9019-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9020-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9021-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9022-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9023-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9024-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9025-3PH	Stable*	Stable*	Stable*	Stable*	Stable*	Stable*
FLT9026-3PH	Stable*	Stable*	Stable*	Stable*	Stable*	Stable*
FLT9027-3PH	Stable*	Stable*	Stable*	Stable*	Stable*	Stable*
FLT9028-3PH	Stable*	Stable*	Stable*	Stable*	Stable*	Stable*
FLT9029-3PH	Stable*	Stable*	Stable*	Stable*	Stable*	Stable*
FLT9030-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9031-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9032-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9033-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9034-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9035-3PH	Stable*	Stable*	Stable*	Stable*	Stable*	Stable*
FLT9036-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9037-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9038-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9039-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9040-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9041-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9042-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9043-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9044-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9045-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9046-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9047-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9048-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9049-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9050-3PH	Stable	Stable	Stable	Stable	Stable	Stable

Table 6-2 continued

Fault ID	G09			G09 GGS		
	16WP	17SP	25SP	16WP	17SP	25SP
FLT9051-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9052-3PH	Stable	Stable	Stable	Stable	Stable	Stable
FLT9015-PO1	Stable	Stable	Stable	Stable	Stable	Stable
FLT9023-PO1	Stable	Stable	Stable	Stable	Stable	Stable
FLT9016-PO1	Stable	Stable	Stable	Stable	Stable	Stable
FLT9017-PO1	Stable	Stable	Stable	Stable	Stable	Stable
FLT03-PO2	Stable	Stable	Stable	Stable	Stable	Stable
FLT04-PO2	Stable	Stable	Stable	Stable	Stable	Stable
FLT05-PO2	Stable	Stable	Stable	Stable	Stable	Stable
FLT9001-PO2	Stable	Stable	Stable	Stable	Stable	Stable
FLT9002-PO2	Stable	Stable	Stable	Stable	Stable	Stable
FLT9003-PO2	Stable	Stable	Stable	Stable	Stable	Stable
FLT9004-PO2	Stable	Stable	Stable	Stable	Stable	Stable
FLT9005-PO2	Stable	Stable	Stable	Stable	Stable	Stable
FLT9006-PO2	Stable	Stable	Stable	Stable	Stable	Stable
FLT9016-PO2	Stable	Stable	Stable	Stable	Stable	Stable
FLT9017-PO2	Stable	Stable	Stable	Stable	Stable	Stable
FLT03-PO3	Stable	Stable	Stable	Stable	Stable	Stable
FLT04-PO3	Stable	Stable	Stable	Stable	Stable	Stable
FLT05-PO3	Stable	Stable	Stable	Stable	Stable	Stable
FLT9001-PO3	Stable	Stable	Stable	Stable	Stable	Stable
FLT9002-PO3	Stable	Stable	Stable	Stable	Stable	Stable
FLT9003-PO3	Stable	Stable	Stable	Stable	Stable	Stable
FLT9004-PO3	Stable	Stable	Stable	Stable	Stable	Stable
FLT9005-PO3	Stable	Stable	Stable	Stable	Stable	Stable
FLT9006-PO3	Stable	Stable	Stable	Stable	Stable	Stable
FLT9015-PO3	Stable	Stable	Stable	Stable	Stable	Stable
FLT9023-PO3	Stable	Stable	Stable	Stable	Stable	Stable
FLT9026-PO4	Stable*	Stable*	Stable*	Stable*	Stable*	Stable*
FLT9100-SB	Stable	Stable	Stable	Stable	Stable	Stable
FLT9200-SB	Stable	Stable	Stable	Stable	Stable	Stable
FLT9300-SB	Stable	Stable	Stable	Stable	Stable	Stable
FLT9301-SB	Stable	Stable	Stable	Stable	Stable	Stable
FLT9400-SB	Stable	Stable	Stable	Stable	Stable	Stable
FLT9401-SB	Stable	Stable	Stable	Stable	Stable	Stable
FLT9402-SB	Stable	Stable	Stable	Stable	Stable	Stable

Table 6-2 continued

Fault ID	G09			G09 GGS		
	16WP	17SP	25SP	16WP	17SP	25SP
FLT9403-SB	Stable	Stable	Stable	Stable	Stable	Stable
FLT9404-SB	Stable	Stable	Stable	Stable	Stable	Stable

*Generator 635020 ATCHSNW1 could not ride through low voltages due to its protective relay settings. This was also observed prior to the Modification Request Changed in this Study.

7.0 Conclusions

The Interconnection Customer for GEN-2013-002 and GEN-2013-019 requested a Modification Request Impact Study to assess the impact of the point of interconnection, turbine and facility changes presented in Table 7-1 below.

Table 7-1: Modification Request

Facility	Existing	Modification Request
Point of Interconnection	Tap on Sheldon to SW 7th Bennet 115 kV Line (560746)	Monolith 115 kV Substation (640591)
Configuration/Capacity	22 x Siemens 2.3 MW 32 x Siemens 2.3 MW	22 x GE 2.3 MW 32 x GE 2.3 MW
Generation Interconnection Line(s)	Length = 1.05 miles R = 0.000700 pu X = 0.005300 pu B = 0.000900 pu *Zero impedance line is included in original case	Length = 3.00 miles R = 0.002650 X = 0.016020 B = 0.002390 *Zero impedance line is included in new case
Main Substation Transformer	T1: Z = 8.5%, Rating 55 MVA T2: Z = 8.0%, Rating 75 MVA	T1: Z = 8.0%, Rating 140 MVA
Equivalent Collector Line 1	R = 0.027860 pu X = 0.034740 pu B = 0.026680 pu	R = 0.006773 X = 0.010646 B = 0.062520
Equivalent Collector Line 2	R = 0.028910 pu X = 0.034140 pu B = 0.053810 pu	N/A

The power factor analysis was performed for all N-1 contingencies performed in the stability analysis using all six models. The minimum leading power factor (generation facility absorbing reactive power from the network) were found to be 0.877 pf (68.21 MVAr) in the 2017 and 0.805 pf (91.43 MVAr) in the 2017 summer peak GGS case. The GEN-2013-002 & GEN-2013-019 project turbines have +/-0.90 pf capability. Per SPP Tariff requirements, the Generating Facilities will be required to meet the standard 95% power factor requirement at the Point of Interconnection. The customer may be required to add capacitor and/or reactor banks depending upon its final collector system design.

The results of the reactive power analysis, also known as the low-wind/no-wind condition analysis, performed using all three models showed that the combined GEN-2013-002 and GEN-2013-019 project may require a 6.5 MVAr shunt reactor on the 115 kV bus of the project substation. The shunt reactor is needed to reduce the reactive power transfer at the POI to approximately zero during low/no wind conditions while the generation interconnection project remains connected to the grid.

The results from short circuit analysis showed that the maximum change in the fault currents in the immediate systems at or near GEN-2013-002 and GEN-2013-019 was 1.6 kA. The largest fault currents calculated were below 43 kA for the 2017SP models and 44 kA for the 2025SP models.

The results of the dynamic stability analysis showed that there were no machine rotor angle damping or transient voltage recovery violations observed in the simulated fault events.

Additionally, the project wind farm 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.