GEN-2015-069

Impact Restudy for Generator Modification (Turbine Change)

Published September 2018

By SPP Generator Interconnections Dept.

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
9/12/2018	SPP	Initial draft report issued.

CONTENTS

SUMMARY

The GEN-2015-069 Interconnection Customer has requested a modification to its Interconnection Request. SPP has performed this system impact restudy to determine the effects of changing wind turbine generators from the previously studied one hundred, fifty (150) Vestas V110 2.0MW wind turbine generators to ninety-five (95) Acciona 3.15 MW wind turbine generators. The total nameplate changes from 300 MW to 299.25 MW. The point of interconnection (POI) for GEN-2015-069 is at Westar (WERE) Union Ridge 230kV substation.

This study was performed to determine whether the request for modification is considered Material. To determine this, study models that included Interconnection Requests through DISIS-2016-001 were used that analyzed the timeframes of 2016 winter, 2017 summer, and 2025 summer models.

The restudy showed that the stability analysis has determined with all previously assigned Network Upgrades in service, generators in the monitored areas remained stable and within the pre-contingency, voltage recovery, and post fault voltage recovery criterion of 0.7pu to 1.2pu for the entire modeled disturbances. 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 requested modification is not considered Material.

A power factor analysis was previously performed and remains valid. The facility will be required to maintain a 95% lagging (providing VARs) and 95% leading (absorbing VARs) power factor at the POI. A low-wind/no-wind condition analysis was performed identifying a need for 18.8 MVAr of reactive compensation. 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. Reactive compensation can be provided either by discrete reactive devices or by the generator itself if it possesses that capability.

With the assumptions outlined in this report and with all the required network upgrades from the DISIS 2015-002 in place, GEN-2015-069 with the ninety-five (95) Acciona 3.15 MW wind turbine generators should be able to interconnect reliably to the SPP transmission grid.

It should be noted that this study analyzed the requested modification to change generator technology, manufacturer, 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.

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-2015-069 Modification Request Impact Study

Revision R1

Date of Submittal
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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 GEN-2015-069, an active generation interconnection request with point of interconnection (POI) at the Union Ridge 230 kV Substation.

The GEN-2015-069 project has proposed to interconnect in the Westar Energy (WERE) control area with a capacity of 300 MW including 150 x Vestas V110 2.0 MW wind turbines as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2015-069 to change turbine configuration change to 95 x Acciona 3.15 MW turbines for a total capacity of 299.25 MW. 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-2015-069 Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2015-069	300	150 x Vestas V110 2.0 MW	Union Ridge 230 kV Substation (532874)

Table ES-2: GEN-2015-069 Modification Request

Facility	Existing	Modification Request
Point of Interconnection	Union Ridge 230 kV Substation (532874)	Union Ridge 230 kV Substation (532874)
Configuration/Capacity	150 x Vestas V110 2.0 MW = 300 MW	95 x Acciona 3.15 MW turbines (299.25 MW)
Generation Interconnection Line	Length = 16.37 miles R = 0.001530 pu X = 0.017980 pu B = 0.064180 pu	Length = 17.5 miles R = 0.002110 pu X = 0.018760 pu B = 0.068318 pu
Main Substation Transformer	T1: Z = 9%, Rating 200 MVA T2: Z = 9%, Rating 200 MVA	T1: Z = 9.2%, Rating 227 MVA T2: Z = 7.8%, Rating 110 MVA
Equivalent Collector Line	R = 0.003830 pu X = 0.006110 pu B = 0.214230 pu	R = 0.005416 pu X = 0.007792 pu B = 0.119474 pu

GEN-2015-069 was last studied as part of Group 8 in the DISIS-2015-002 ReStudy #4 published on February 2016. Aneden performed reactive power analysis, short circuit analysis and dynamic stability analysis using the modification request data based on the DISIS-2016-001 ReStudy #1 Group 8 study models:

1. 2016 Winter Peak (2016WP),
2. 2017 Summer Peak (2017SP) and
3. 2025 Summer Peak (2025SP).

Note that in the 2017SP and 2025SP scenario, there is a new substation Bluestem that is not in-service in the 2016WP. 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 three models. The minimum power factor (generation facility absorbing reactive power from the network) was found to be 0.997 pf (21.49 MVAr contribution) in the 2016 winter peak case for the loss of the Union Ridge to Summit 230 kV line. The GEN-2015-069 project turbines have +/-0.95 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 GEN-2015-069 project may require an 18.8 MVAr shunt reactor on the 230 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 ReStudy #4 showed a need for a 27.9 MVAr shunt reactor. The difference in the results may be attributed to the changes to the generation interconnection line and the collector system impedances.

The results from short circuit analysis showed that the maximum change in the fault currents in the immediate systems at or near GEN-2015-069 was 1.548 kA. All three-phase current levels with the GEN-2015-069 generator online was below 38 kA and 44 kA in the 2017SP and 2025SP models respectively.

The dynamic stability analysis was performed using the three loading scenarios 2016 Winter Peak, 2017 Summer Peak and 2025 Summer Peak simulating up to 48 contingencies that included three-phase faults, three phase faults on prior outage cases, and single-line-to-ground faults 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-2015-069 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-2015-069, an active generation interconnection request with point of interconnection (POI) at the Union Ridge 230 kV Substation.

The GEN-2015-069 project has proposed to interconnect in the Westar Energy (WERE) control area with a capacity of 300 MW including 150 x Vestas V110 2.0 MW wind turbines as shown in Table 1-1 below. Details of the modification request as provided in Section 2.0 below.

Table 1-1: Existing GEN-2015-069 Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2015-069	300	150 x Vestas V110 2.0 MW	Union Ridge 230 kV Substation (532874)

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 Requirement
3. Reactive Power Analysis
4. Short Circuit Analysis
5. Dynamic Stability Analysis
6. Conclusions

Aneden performed a 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 three DISIS-2016-001 ReStudy #1 study models:

1. 2016 Winter Peak (2016WP),
2. 2017 Summer Peak (2017SP), and
3. 2025 Summer Peak (2025SP).

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

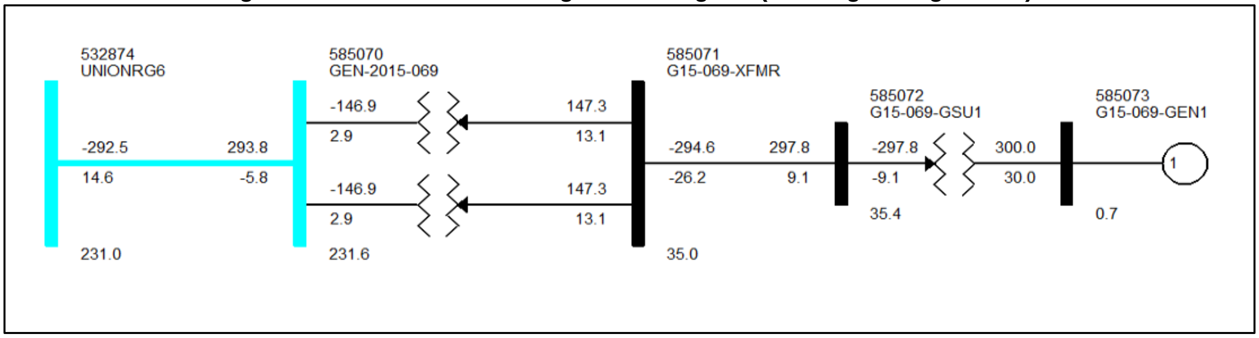
1.2 Study Limitations

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-2015-069 configuration. GEN-2015-069 was last studied as part of Group 8 in the DISIS-2015-002 ReStudy #4 (ReStudy #4) published on February 2016.

Figure 2-1: GEN-2015-069 Single Line Diagram (Existing Configuration)



The GEN-2015-069 Modification Request included a turbine change to 95 x Acciona 3.15 MW turbines for a total capacity of 299.25 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.

Figure 2-2: GEN-2015-069 Single Line Diagram (New Configuration)

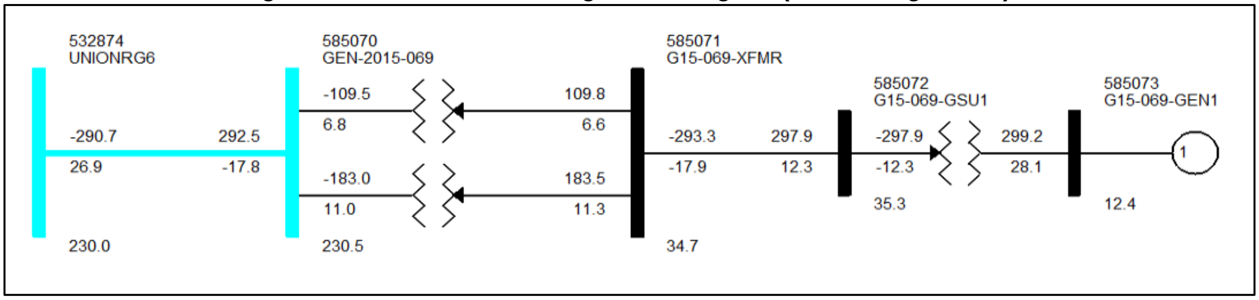


Table 2-1: GEN-2015-069 Modification Request

Facility	Existing	Modification Request
Point of Interconnection	Union Ridge 230 kV Substation (532874)	Union Ridge 230 kV Substation (532874)
Configuration/Capacity	150 x Vestas V110 2.0 MW = 300 MW	95 x Acciona 3.15 MW turbines (299.25 MW)
Generation Interconnection Line	Length = 16.37 miles R = 0.001530 pu X = 0.017980 pu B = 0.064180 pu	Length = 17.5 miles R = 0.002110 pu X = 0.018760 pu B = 0.068318 pu
Main Substation Transformer	T1: Z = 9%, Rating 200 MVA T2: Z = 9%, Rating 200 MVA	T1: Z = 9.2%, Rating 227 MVA T2: Z = 7.8%, Rating 110 MVA
Equivalent Collector Line	R = 0.003830 pu X = 0.006110 pu B = 0.214230 pu	R = 0.005416 pu X = 0.007792 pu B = 0.119474 pu

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 and 2025SP models. The methodology and results of the power flow analysis are described below. The analysis was completed using PSS/E version 32 software. The detail results are provided in Appendix A.

3.1 Methodology

GEN-2015-069 generator was 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. The replacement generators' reactive power capability was set to +/- 9999 MVAr to find the required power factor.

Table 3-1: Base Case GEN-2015-069 POI Bus Voltages

Machine	PF Capability	POI Bus Number	POI Bus Name	Initial POI Voltage (pu)		
				16WP	17SP	25SP
GEN-2015-069	±0.95	532874	UNIONRG6	1.0043	1.0124	1.0144

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-2015-069 facility for the N-1 three phase contingencies are presented in Appendix A. There were no contingencies that required a generator power factor beyond the capability (from 0.95 lagging to 0.95 leading) of the studied renewable energy project. The minimum power factor (generation facility absorbing reactive power from the network) was found to be 0.997 pf (21.49 MVAr contribution) in the 2016 winter peak case for the loss of the Union Ridge to Summit 230 kV line. The GEN-2015-069 project turbines have +/-0.95 pf capability. 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-2015-069 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-2015-069 project, the generator was switched out of service while other collector system elements remained in-service. A shunt reactor was tested at the study project substation high side bus to bring the MVAr flow into the POI down to approximately zero.

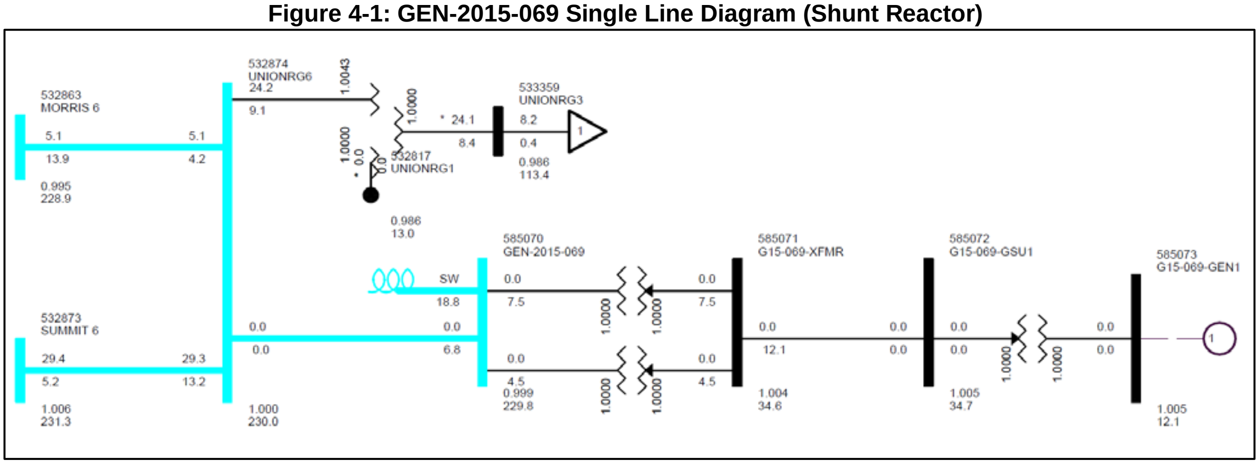
4.2 Results

The results from the reactive power analysis showed that the GEN-2015-069 project required approximately 18.8 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 collector systems. 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.

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

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)		
			16WP	17SP	25SP
GEN-2015-069	532874	UNIONRG6	18.8	18.8	18.8

Figure 4-1: GEN-2015-069 Single Line Diagram (Shunt Reactor)



5.0 Short Circuit Analysis

A short-circuit study was performed on the power flow models for the 2017SP and 2025SP models for GEN-2015-069 using the modified Cluster Scenario models. 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 Union Ridge 230kV 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 are summarized in Table 5-1 and Table 5-2 for the 2017SP and 2025SP models, respectively. The maximum increase in fault current was about 1.548 kA. The maximum fault current calculated within 5 buses with GEN-2015-069 was less than 38 kA and 44 kA for the 2017SP and 2025SP models respectively.

Table 5-1: 2017SP Short Circuit Results

Bus Distance	Max. Change (kA)	Max %Change
0	1.548	21.5%
1	0.585	4.7%
2	0.446	3.9%
3	0.207	1.7%
4	0.207	1.7%
5	0.185	1.6%

Table 5-2: 2025SP Short Circuit Results

Bus Distance	Max. Change (kA)	Max %Change
0	1.546	21.2%
1	0.577	4.4%
2	0.422	3.8%
3	0.189	1.5%
4	0.189	1.5%
5	0.167	1.4%

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the turbine change and other modifications to the GEN-2015-069 project. 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 95 x Acciona 3.15 MW turbine configuration for the GEN-2015-069 generating facility. 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 (DISIS-2016-001-1) for Group 8 including network upgrades identified in that restudy. The modifications requested to project GEN-2015-069 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-2016-001-1 (Group 8) request, GEN-2015-069 is provided in Appendix D.

During the fault simulations, the active power (PELEC), reactive power (QELEC) and terminal voltage (ETERM) were monitored for GEN-2015-069 and other equally and prior queued projects in Group 8. In addition, voltages of five (5) buses away from the POI of GEN-2015-069 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), 540 (GMO) and 541 (KCPL) 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-2015-069 in the DISIS-2015-002 Group 8 ReStudy #4 and included additional faults based on the location of the 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 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.

Table 6-1: Fault Definitions

Fault Name	Description
FLT52-3PH	3 Phase Fault on UNIONRG6 (532874) to SUMMIT 6 (532873) 230.0 kV Line circuit 1 near UNIONRG6 (532874)
	a. Apply three-phase fault at UNIONRG6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT53-3PH	3 Phase Fault on UNIONRG6 (532874) to MORRIS 6 (532863) 230.0 kV Line circuit 1 near UNIONRG6 (532874)
	a. Apply three-phase fault at UNIONRG6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT54-3PH	3 Phase Fault on SUMMIT 6 (532873) to EMCPHER6 (532872) 230.0 kV Line circuit 1 near SUMMIT 6 (532873)
	a. Apply three-phase fault at SUMMIT 6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT55-3PH	3 Phase Fault on SUMMIT 6 (532873) to SMOKYHL6 (530592) 230.0 kV Line circuit 1 near SUMMIT 6 (532873)
	a. Apply three-phase fault at SUMMIT 6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT56-3PH	3 Phase Fault on SUMMIT 6 (532873) 230.0 kV /SUMMIT 7 (532773) 345.0 kV / SUMMIT 1 (532813) 14.4 kV transformer circuit 1 near SUMMIT 6 (532873)
	a. Apply three-phase fault at SUMMIT 6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT57-3PH	3 Phase Fault on SUMMIT 6 (532873) 230.0 kV /SUMMIT 3 (533381) 115.0 kV / SUMIT2 1 (532896) 13.8 kV transformer circuit 1 near SUMMIT 6 (532873)
	a. Apply three-phase fault at SUMMIT 6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT58-3PH	3 Phase Fault on MORRIS 6 (532863) to MCDOWEL6 (532862) 230.0 kV Line circuit 1 near MORRIS 6 (532863)
	a. Apply three-phase fault at MORRIS 6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.

Table 6-1 continued

Fault Name	Description
FLT59-3PH	3 Phase Fault on MORRIS 6 (532863) to SWISVAL6 (532856) 230.0 kV Line circuit 1 near MORRIS 6 (532863)
	a. Apply three-phase fault at MORRIS 6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT60-3PH	3 Phase Fault on MORRIS 6 (532863) 230.0 kV /MORRIS 3 (533305) 115.0 kV / MORRIS2X1 (532890) 13.8 kV transformer circuit 1 near MORRIS 6 (532863)
	a. Apply three-phase fault at MORRIS 6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT61-3PH	3 Phase Fault on MORRIS 6 (532863) 230.0 kV /MORRIS 7 (532770) 345.0 kV / MORRIS1X1 (532809) 14.4 kV transformer near MORRIS 6 (532863)
	a. Apply three-phase fault at MORRIS 6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT109-SB	Stuck Breaker Single Phase Fault on UNIONRG6 (532874) to SUMMIT 6 (532873) 230.0 kV line circuit 1 near UNIONRG6 (532874)
	a. Apply single-phase fault at UNIONRG6 230.0 kV bus
	b. Wait for 20 cycles then open UNIONRG6 (532874) to SUMMIT 6 (532873) 230.0 kV Line circuit 1
	c. Trip UNIONRG6 (532874) to MORRIS 6 (532863) 230.0 kV Line circuit 1 and remove the fault
FLT121-SB	Stuck Breaker Single Phase Fault on UNIONRG6 (532874) to SUMMIT 6 (532873) 230.0 kV line circuit 1 near UNIONRG6 (532874)
	a. Apply single-phase fault at UNIONRG6 230.0 kV bus
	b. Wait for 20 cycles then open UNIONRG6 (532874) to SUMMIT 6 (532873) 230.0 kV Line circuit 1
	c. Trip UNIONRG6 (532874) 230.0 kV /UNIONRG3 (533359) 115.0 kV / UNIONRG1 (532817) 13.2 kV transformer circuit 1 and remove the fault
FLT9001-3PH	3 Phase Fault on UNIONRG6 (532874) 230.0 kV /UNIONRG3 (533359) 115.0 kV / UNIONRG1 (532817) 13.2 kV transformer circuit 1 near UNIONRG6 (532874)
	a. Apply three-phase fault at UNIONRG6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT9002-3PH	3 Phase Fault on UNIONRG3 (533359) to TCHOPE 3 (533360) 115.0 kV Line circuit 1 near UNIONRG3 (533359)
	a. Apply three-phase fault at UNIONRG3 115.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT9003-3PH	3 Phase Fault on SMOKYHL6 (530592) to KNOLL 6 (530558) 230.0 kV Line circuit 1 near SMOKYHL6 (530592)
	a. Apply three-phase fault at SMOKYHL6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.

Table 6-1 continued

Fault Name	Description
FLT9004-3PH	3 Phase Fault on SMOKYHL6 (530592) to SMKYP1 6 (530593) 230.0 kV Line circuit 1 near SMOKYHL6 (530592)
	a. Apply three-phase fault at SMOKYHL6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT9005-3PH	3 Phase Fault on SMOKYHL6 (530592) to SMKYP2 6 (530599) 230.0 kV Line circuit 1 near SMOKYHL6 (530592)
	a. Apply three-phase fault at SMOKYHL6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT9006-3PH	3 Phase Fault on MORRIS 7 (532770) to JEC N 7 (532766) 345.0 kV Line circuit 1 near MORRIS 7 (532770)
	a. Apply three-phase fault at MORRIS 7 345.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT9007-3PH	3 Phase Fault on MORRIS 7 (532770) to EMPEC 7 (532768) 345.0 kV Line circuit 1 near MORRIS 7 (532770)
	a. Apply three-phase fault at MORRIS 7 345.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT9008-3PH*	3 Phase Fault on SUMMIT 7 (532773) to BLUSTEM7 (532767) 345.0 kV Line circuit 1 near SUMMIT 7 (532773)
	a. Apply three-phase fault at SUMMIT 7 345.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT9008-3PH_16WP	3 Phase Fault on SUMMIT 7 (532773) to JEC N 7 (532766) 345.0 kV Line circuit 1 near SUMMIT 7 (532773)
	a. Apply three-phase fault at SUMMIT 7 345.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT9009-3PH	3 Phase Fault on SUMMIT 7 (532773) to RENO 7 (532771) 345.0 kV Line circuit 1 near SUMMIT 7 (532773)
	a. Apply three-phase fault at SUMMIT 7 345.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.

*Only applies to the 2017SP and 2025SP models

Table 6-1 continued

Fault Name	Description
FLT9010-3PH	3 Phase Fault on SUMMIT 7 (532773) to ELMCREEK7 (539805) 345.0 kV Line circuit 1 near SUMMIT 7 (532773)
	a. Apply three-phase fault at SUMMIT 7 345.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT9011-3PH	3 Phase Fault on EMCPHER6 (532872) to CIRCLE 6 (532871) 230.0 kV Line circuit 1 near EMCPHER6 (532872)
	a. Apply three-phase fault at EMCPHER6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT9012-3PH	3 Phase Fault on EMCPHER6 (532872) 230.0 kV /EMCPHER3 (533417) 115.0 kV / EMCPHER1 (532894) 13.8 kV transformer circuit 1 near EMCPHER6 (532872)
	a. Apply three-phase fault at EMCPHER6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT9013-3PH	3 Phase Fault on SWISVAL6 (532856) to AUBURN 6 (532851) 230.0 kV Line circuit 1 near SWISVAL6 (532856)
	a. Apply three-phase fault at SWISVAL6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT9014-3PH	3 Phase Fault on SWISVAL6 (532856) to LAWHILL6 (532853) 230.0 kV Line circuit 1 near SWISVAL6 (532856)
	a. Apply three-phase fault at SWISVAL6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT9015-3PH	3 Phase Fault on SWISVAL6 (532856) to TECHILL6 (532857) 230.0 kV Line circuit 1 near SWISVAL6 (532856)
	a. Apply three-phase fault at SWISVAL6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT9016-3PH	3 Phase Fault on SWISVAL6 (532856) 230.0 kV /SWISVAL7 (532774) 345.0 kV / SWISV1X1 (532815) 14.4 kV transformer circuit 1 near SWISVAL6 (532856)
	a. Apply three-phase fault at SWISVAL6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted transformer.

Table 6-1 continued

Fault Name	Description
FLT9017-3PH	3 Phase Fault on MORRIS 3 (533305) to WEMPORI3 (533309) 115.0 kV Line circuit 1 near MORRIS 3 (533305)
	a. Apply three-phase fault at MORRIS 3 115.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT9018-3PH	3 Phase Fault on MCDOWEL6 (532862) 230.0 kV /MCDOWEL3 (533335) 115.0 kV / MCDOWL 1 (532898) 13.8 kV transformer circuit 1 near MCDOWEL6 (532862)
	a. Apply three-phase fault at MCDOWEL6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT9019-3PH	3 Phase Fault on SUMMIT 3 (533381) to EXIDE J3 (533368) 115.0 kV Line circuit 1 near SUMMIT 3 (533381)
	a. Apply three-phase fault at SUMMIT 3 115.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT9020-3PH	3 Phase Fault on SUMMIT 3 (533381) to NORTHVW3 (533371) 115.0 kV Line circuit 1 near SUMMIT 3 (533381)
	a. Apply three-phase fault at SUMMIT 3 115.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT9021-3PH	3 Phase Fault on SUMMIT 3 (533381) to SO GATE3 (533379) 115.0 kV Line circuit 1 near SUMMIT 3 (533381)
	a. Apply three-phase fault at SUMMIT 3 115.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT54-PO1	Prior Outage of UNIONRG6 (532874) to MORRIS 6 (532863) 230.0 kV Line circuit 1 then 3 Phase Fault on SUMMIT 6 (532873) to EMCPHER6 (532872) 230.0 kV Line circuit 1 near SUMMIT 6 (532873)
	a. Apply three-phase fault at SUMMIT 6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT55-PO1	Prior Outage of UNIONRG6 (532874) to MORRIS 6 (532863) 230.0 kV Line circuit 1 then 3 Phase Fault on SUMMIT 6 (532873) to SMOKYHL6 (530592) 230.0 kV Line circuit 1 near SUMMIT 6 (532873)
	a. Apply three-phase fault at SUMMIT 6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.

Table 6-1 continued

Fault Name	Description
FLT56-PO1	Prior Outage of UNIONRG6 (532874) to MORRIS 6 (532863) 230.0 kV Line circuit 1 then 3 Phase Fault on SUMMIT 6 (532873) 230.0 kV /SUMMIT 7 (532773) 345.0 kV / SUMMIT 1 (532813) 14.4 kV transformer circuit 1 near SUMMIT 6 (532873)
	a. Apply three-phase fault at SUMMIT 6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT57-PO1	Prior Outage of UNIONRG6 (532874) to MORRIS 6 (532863) 230.0 kV Line circuit 1 then 3 Phase Fault on SUMMIT 6 (532873) 230.0 kV /SUMMIT 3 (533381) 115.0 kV / SUMIT2 1 (532896) 13.8 kV transformer circuit 1 near SUMMIT 6 (532873)
	a. Apply three-phase fault at SUMMIT 6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT9002-PO1	Prior Outage of UNIONRG6 (532874) to MORRIS 6 (532863) 230.0 kV Line circuit 1 then 3 Phase Fault on UNIONRG3 (533359) to TCHOPE 3 (533360) 115.0 kV Line circuit 1 near UNIONRG3 (533359)
	a. Apply three-phase fault at UNIONRG3 115.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT58-PO2	Prior Outage of UNIONRG6 (532874) to SUMMIT 6 (532873) 230.0 kV Line circuit 1 then 3 Phase Fault on MORRIS 6 (532863) to MCDOWEL6 (532862) 230.0 kV Line circuit 1 near MORRIS 6 (532863)
	a. Apply three-phase fault at MORRIS 6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT59-PO2	Prior Outage of UNIONRG6 (532874) to SUMMIT 6 (532873) 230.0 kV Line circuit 1 then 3 Phase Fault on MORRIS 6 (532863) to SWISVAL6 (532856) 230.0 kV Line circuit 1 near MORRIS 6 (532863)
	a. Apply three-phase fault at MORRIS 6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT60-PO2	Prior Outage of UNIONRG6 (532874) to SUMMIT 6 (532873) 230.0 kV Line circuit 1 then 3 Phase Fault on MORRIS 6 (532863) 230.0 kV /MORRIS 3 (533305) 115.0 kV / MORRIS2X1 (532890) 13.8 kV transformer circuit 1 near MORRIS 6 (532863)
	a. Apply three-phase fault at MORRIS 6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT61-PO2	Prior Outage of UNIONRG6 (532874) to SUMMIT 6 (532873) 230.0 kV Line circuit 1 then 3 Phase Fault on MORRIS 6 (532863) 230.0 kV /MORRIS 7 (532770) 345.0 kV / MORRIS1X1 (532809) 14.4 kV transformer circuit 1 near MORRIS 6 (532863)
	a. Apply three-phase fault at MORRIS 6 230.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted transformer.

Table 6-1 continued

Fault Name	Description
FLT9002-PO2	Prior Outage of UNIONRG6 (532874) to SUMMIT 6 (532873) 230.0 kV Line circuit 1 then 3 Phase Fault on UNIONRG3 (533359) to TCHOPE 3 (533360) 115.0 kV Line circuit 1 near UNIONRG3 (533359)
	a. Apply three-phase fault at UNIONRG3 115.0 kV bus
	b. Clear fault after 5 cycles by tripping the faulted line.
	c. Wait for 20 cycles then reclose the line in (b) back into the fault.
	d. Leave fault on for 5 cycles, then trip line in (b) and remove fault.
FLT9100-SB	**Stuck Breaker on SUMMIT 6 (532873) 230.0 kV /SUMMIT 7 (532773) 345.0 kV / SUMMIT 1 (532813) 14.4 kV transformer**
	a. Apply single phase fault at SUMMIT 6 230.0 kV bus
	b. After 16 cycles, trip the Summit 230/ SUMMIT 3 (533381) 115 kV / SUMIT 3 (532896) 13.8 kV Transformer T1
	c. Trip the SUMMIT 6 (532873) 230.0 kV /SUMMIT 7 (532773) 345.0 kV / SUMMIT 1 (532813) 14.4 kV transformer, and remove the fault
FLT9200-SB	**Stuck Breaker on MORRIS 6 (532863) 230.0 kV /MORRIS 7 (532770) 345.0 kV / MORRIS1X1 (532809) 14.4 kV transformer**
	a. Apply single phase fault at MORRIS 6 230.0 kV bus
	b. After 16 cycles, trip the MORRIS 6 (532863) to MCDOWEL6 (532862) 230.0 kV Line circuit 1
	c. Trip the MORRIS 6 (532863) 230.0 kV /MORRIS 7 (532770) 345.0 kV / MORRIS1X1 (532809) 14.4 kV transformer, and remove the fault

6.3 Results

Table 6-2 shows the results of the fault events simulated for each of the models. There were no damping or voltage recovery violations observed during the simulations and the system returned to stable conditions following each of the fault events. 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-2015-069 Dynamic Stability Results

Fault Name	16WP	17SP	25SP
FLT52-3PH	Stable	Stable	Stable
FLT53-3PH	Stable	Stable	Stable
FLT54-3PH	Stable	Stable	Stable
FLT55-3PH	Stable	Stable	Stable
FLT56-3PH	Stable	Stable	Stable
FLT57-3PH	Stable	Stable	Stable
FLT58-3PH	Stable	Stable	Stable
FLT59-3PH	Stable	Stable	Stable
FLT60-3PH	Stable	Stable	Stable
FLT61-3PH	Stable	Stable	Stable
FLT109-SB	Stable	Stable	Stable
FLT121-SB	Stable	Stable	Stable
FLT9001-3PH	Stable	Stable	Stable
FLT9002-3PH	Stable	Stable	Stable
FLT9003-3PH	Stable	Stable	Stable
FLT9004-3PH	Stable	Stable	Stable
FLT9005-3PH	Stable	Stable	Stable
FLT9006-3PH	Stable	Stable	Stable

Table 6-2 continued

Fault Name	16WP	17SP	25SP
FLT9007-3PH	Stable	Stable	Stable
FLT9008-3PH	N/A	Stable	Stable
FLT9008-3PH_16WP	Stable	N/A	N/A
FLT9009-3PH	Stable	Stable	Stable
FLT9010-3PH	Stable	Stable	Stable
FLT9011-3PH	Stable	Stable	Stable
FLT9012-3PH	Stable	Stable	Stable
FLT9013-3PH	Stable	Stable	Stable
FLT9014-3PH	Stable	Stable	Stable
FLT9015-3PH	Stable	Stable	Stable
FLT9016-3PH	Stable	Stable	Stable
FLT9017-3PH	Stable	Stable	Stable
FLT9018-3PH	Stable	Stable	Stable
FLT9019-3PH	Stable	Stable	Stable
FLT9020-3PH	Stable	Stable	Stable
FLT9021-3PH	Stable	Stable	Stable
FLT54-PO1	Stable	Stable	Stable
FLT55-PO1	Stable	Stable	Stable
FLT56-PO1	Stable	Stable	Stable
FLT57-PO1	Stable	Stable	Stable
FLT9002-PO1	Stable	Stable	Stable
FLT58-PO2	Stable	Stable	Stable
FLT59-PO2	Stable	Stable	Stable
FLT60-PO2	Stable	Stable	Stable
FLT61-PO2	Stable	Stable	Stable
FLT9002-PO2	Stable	Stable	Stable
FLT9100-SB	Stable	Stable	Stable
FLT9200-SB	Stable	Stable	Stable

7.0 Conclusions

The Interconnection Customer for GEN-2015-069 requested a Modification Request Impact Study to assess the impact of the turbine and facility changes presented in Table 7-1 below.

Table 7-1: Modification Request

Facility	Existing	Modification Request
Point of Interconnection	Union Ridge 230 kV Substation (532874)	Union Ridge 230 kV Substation (532874)
Configuration/Capacity	150 x Vestas V110 2.0 MW = 300 MW	95 x Acciona 3.15 MW turbines (299.25 MW)
Generation Interconnection Line	Length = 16.37 miles R = 0.001530 pu X = 0.017980 pu B = 0.064180 pu	Length = 17.5 miles R = 0.002110 pu X = 0.018760 pu B = 0.068318 pu
Main Substation Transformer	T1: Z = 9%, Rating 200 MVA T2: Z = 9%, Rating 200 MVA	T1: Z = 9.2%, Rating 227 MVA T2: Z = 7.8%, Rating 110 MVA
Equivalent Collector Line	R = 0.003830 pu X = 0.006110 pu B = 0.214230 pu	R = 0.005416 pu X = 0.007792 pu B = 0.119474 pu

The power factor analysis performed showed that the lowest power factor (generation facility contributing reactive power from the network) was found to be 0.997 pf (21.49 MVAr contribution). 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 GEN-2015-069 project may require an 18.8 MVAr shunt reactor on the 230 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 short circuit analysis showed the maximum increase in fault current caused by GEN-2015-069 did not exceed 1.548 kA. The largest fault current calculated was below 38 kA and 44 kA for the 2017SP and 2025SP models respectively.

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 and the system achieved stable operation after each fault event. 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.

In conclusion, the results of this Study showed that the Modification Request shown in Table 7-1 do not constitute a material modification.