Southwest Power Pool

GEN-2015-034 & GEN-2016-022

Impact Restudy for Generator Modification (Turbine Change)

Published July 2019
By SPP Generator Interconnections Dept.

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
07/12/2019	SPP	Initial report issued.

CONTENTS

SUMMARY

The GEN-2015-034 and GEN-2016-022 Interconnection Customer has requested a modification to its 200 MW and 151.8 MW interconnection requests. The GEN-2015-034 system impact restudy was performed to determine the effects of changing wind turbine generators from the previously studied 57 Vestas V136 GS 3.45MW and 1 Vestas V136 GS 3.35MW to 39 Nordex 4.8 MW, 2 Nordex 4.8 MW (Derated to 4.2 MW), and 1 Nordex 4.8 MW (Derated to 4.4 MW), for a total capacity of 200 MW. GEN-2016-022 was also studied to determine the effects of changing wind turbine generators from the previously studied 44 Vestas V110 V126 GS 3.45 MW to 29 Nordex 4.8 MW and 3 Nordex 4.8 MW (Derated to 4.2 MW) for a total capacity of 151.8 MW. In addition, both modification requests included changes to the generation interconnection line, collection system and the generator substation transformer. The point of interconnection (POI) for GEN-2015-034 and GEN-2016-022 remains at the Ranch Road 345kV Substation.

This study was performed by Aneden Consulting to determine whether the request for modification is considered Material. A short circuit analysis, a low-wind/no-wind condition analysis, and stability analysis was performed for this modification request. The study report follows this executive summary.

The generating facility will be required to maintain a 95% lagging (providing VARs) and 95% leading (absorbing VArs) in accordance with FERC Order 827. Additionally, GEN-2015-034 and GEN-2016-022 will be required to install approximately 9.89 MVArs and 9.13 MVArs of reactor shunts on its substation 345 kV bus or provide an alternate means of reactive power 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.

There were no other 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 requested modification is not considered Material.

It should be noted that this study analyzed the requested modification to change generator technology and layout. Powerflow analysis was not performed. 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

Report On

GEN-2015-034 and GEN-2016-022 Modification Request Impact Study

Revision R0

Date of Submittal
June 26, 2019

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Executive Summary

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The GEN-2015-034 and GEN-2016-022 projects were proposed to interconnect in Oklahoma Gas & Electric (OKGE) control area with a respective capacities of 200 MW and 151.8 MW respectively as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2015-034 to change turbine configuration change to a total of 39 x Nordex N149 4.8 MW + 2 x Nordex N149 4.8 MW (Derated to 4.2 MW) + 1 x Nordex N149 4.8 MW (Derated to 4.4 MW), for a total capacity of 200 MW as well as the modification of GEN-2016-022 to change turbine configuration change to a total of 29 x Nordex N149 4.8 MW + 3 x Nordex N149 4.8 MW (Derated to 4.2 MW) for a total capacity of 151.8 MW. In addition, the modification request included changes to the generation interconnection line, collection system and the generator substation transformer. The modification request changes for GEN-2015-034 and GEN-2016-022 are shown in Table ES-2 and Table ES-3 respectively.

Table ES-1: Existing GEN-2015-034 and GEN-2016-022 Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2015-034	200	57 x Vestas V136 GS 3.45MW (Gen 1) + 1 x Vestas V136 GS 3.35MW (Gen 2)	Ranch Road 345 kV Substation (515576)
GEN-2016-022	151.8	44 x Vestas V110 V126 GS 3.45 MW	Ranch Road 345 kV Substation (515576)

Table ES-2: GEN-2015-034 Modification Request

<table>
<tr><th>Facility</th><th colspan="2">Existing</th><th colspan="3">Modification Request</th></tr>
<tr><td>Point of Interconnection</td><td colspan="2">Ranch Road 345 kV Substation (515576)</td><td colspan="3">Ranch Road 345 kV Substation (515576)</td></tr>
<tr><td>Configuration/Capacity</td><td colspan="2">57 x Vestas V136 GS 3.45MW (Gen 1) + 1 x Vestas V136 GS 3.35MW (Gen 2) = 200 MW</td><td colspan="3">39 x Nordex N149 4.8 MW (Gen 1) + 2 x Nordex N149 4.8 MW (Derated to 4.2 MW) (Gen 2) + 1 x Nordex N149 4.8 MW (Derated to 4.4 MW) (Gen 3) = 200 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td colspan="2">Length = 5 miles
R = 0.000260 pu
X = 0.002380 pu
B = 0.065180 pu</td><td colspan="3">Length = 5 miles
R = 0.000290 pu
X = 0.003320 pu
B = 0.032160 pu</td></tr>
<tr><td>Main Substation Transformer</td><td colspan="2">Z = 9%, Winding 127 MVA, Rating A 169 MVA, Rating B 211 MVA</td><td colspan="3">Z = 9%, Winding 127 MVA, Rating 211 MVA</td></tr>
<tr><td>GSU Transformer</td><td>Gen 1
Equivalent Qty: 57
Z = 9%, Rating 213.9 MVA</td><td>Gen 2
Equivalent Qty: 1
Z = 9%, Rating 3.6 MVA</td><td>Gen 1
Equivalent Qty: 39
Z = 9.2%, Rating 208.65 MVA</td><td>Gen 2
Equivalent Qty: 2
Z = 9.2%, Rating 10.7 MVA</td><td>Gen 3
Equivalent Qty: 1
Z = 9.2%, Rating 5.35 MVA</td></tr>
<tr><td>Equivalent Collector Line</td><td colspan="2">R = 0.003320 pu
X = 0.003600 pu
B = 0.051610 pu</td><td colspan="3">R = 0.004326 pu
X = 0.005666 pu
B = 0.066370 pu</td></tr>
</table>

Table ES-3: GEN-2016-022 Modification Request

<table>
<tr><th>Facility</th><th>Existing</th><th colspan="2">Modification Request</th></tr>
<tr><td>Point of Interconnection</td><td>Ranch Road 345 kV Substation (515576)</td><td colspan="2">Ranch Road 345 kV Substation (515576)</td></tr>
<tr><td>Configuration/Capacity</td><td>44 x Vestas V110 V126 GS 3.45 MW = 151.8 MW</td><td colspan="2">29 x Nordex N149 4.8 MW (Gen 1) + 3 x Nordex N149 4.8 MW (Derated to 4.2 MW) (Gen 2) = 151.8 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td>Length = 5 miles
R = 0.000260 pu
X = 0.002380 pu
B = 0.065180 pu</td><td colspan="2">Length = 5 miles (Shared with GEN-2015-034)
R = 0.000290 pu
X = 0.003320 pu
B = 0.032160 pu</td></tr>
<tr><td>Main Substation Transformer</td><td>Z = 9%, Winding 100 MVA, Rating 166 MVA</td><td colspan="2">Z = 11%, Winding 100 MVA, Rating 166 MVA</td></tr>
<tr><td>GSU Transformer</td><td>Equivalent Qty: 44
Z = 9%, Rating 165 MVA</td><td>Gen 1 Equivalent Qty: 29:
Z = 9.2%, Rating 155.1 MVA</td><td>Gen 2 Equivalent Qty: 3:
Z = 9.2%, Rating 16 MVA</td></tr>
<tr><td>Equivalent Collector Line</td><td>R = 0.021550 pu
X = 0.052740 pu
B = 0.124130 pu</td><td colspan="2">R = 0.012301 pu
X = 0.018706 pu
B = 0.090381 pu</td></tr>
</table>

GEN-2015-034 and GEN-2016-022 were originally studied as part of Group 8 in the DISIS-2015-002 and DISIS-2016-001 respectively. Aneden performed reactive power analysis, short circuit analysis and dynamic stability analysis using the modification request data using the DISIS-2016-002 ReStudy #1 Group 8 study models:

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

All analyses were performed using the PTI PSS/E version 33.7 software and the results are summarized below.

A power factor analysis was not performed as there was no change in the point of interconnection for GEN-2015-034 and GEN-2016-022.

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-2015-034 requires a 9.89 MVAr shunt reactor on the 345 kV bus of its project substation and GEN-2016-022 requires a 9.13 MVAr shunt reactor on the 345 kV bus of its project substation. The shunt reactors are 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-2015-034 and GEN-2016-022 POI was 0.85 kA. All three-phase current levels with the GEN-2015-034 and GEN-2016-022 generators online were below 45 kA and 44 kA in the 2018SP and 2026SP models respectively.

The dynamic stability analysis was performed using the three loading scenarios 2017 WP, 2018SP and 2026SP simulating up to 65 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 other machine rotor angle damping or transient voltage recovery violations observed in the simulated fault events. Additionally, the project wind farm generators were 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-2015-034 and GEN-2016-022 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-2015-034 and GEN-2016-022, an active generation interconnection request with point of interconnection (POI) on the Ranch Road 345 kV Substation.

The GEN-2015-034 and GEN-2016-022 projects were proposed to interconnect in the Oklahoma Gas & Electric (OKGE) control area with respective capacities of 200 MW and 151.8 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-2015-034 and GEN-2016-022 Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2015-034	200	57 x Vestas V136 GS 3.45MW (Gen 1) + 1 x Vestas V136 GS 3.35MW (Gen 2)	Ranch Road 345 kV Substation (515576)
GEN-2016-022	151.8	44 x Vestas V110 V126 GS 3.45 MW	Ranch Road 345 kV Substation (515576)

1.1 Scope

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

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

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-2016-002 ReStudy #1 study models:

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

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

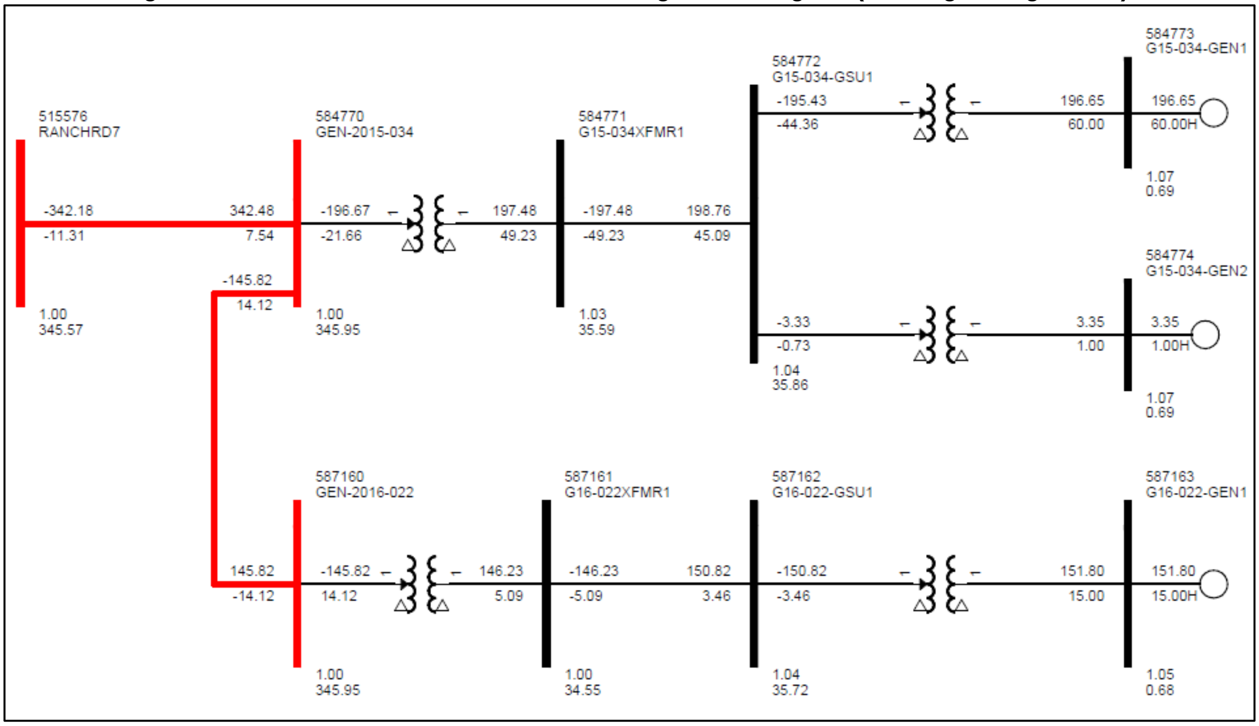
1.2 Study Limitations

The assessments and conclusions provided in this report are based on assumptions and information provided to Aneden by others. While the assumptions and information provided may be appropriate for the purposes of this report, Aneden does not guarantee that those conditions assumed will occur. In addition, Aneden did not independently verify the accuracy or completeness of the information provided. As such, the conclusions and results presented in this report may vary depending on the extent to which actual future conditions differ from the assumptions made or information used herein.

2.0 Project and Modification Request

Figure 2-1 shows the power flow model single line diagram for the existing GEN-2015-034 and GEN-2016-022 configurations. GEN-2015-034 and GEN-2016-022 were originally studied as part of Group 8 in the DISIS-2015-002 and DISIS-2016-001 respectively.

Figure 2-1: GEN-2015-034 & GEN-2016-022 Single Line Diagram (Existing Configuration)



The GEN-2015-034 Modification Request included a turbine change to 39 x Nordex N149 4.8 MW + 2 x Nordex N149 4.8 MW (Derated to 4.2 MW) + 1 x Nordex N149 4.8 MW (Derated to 4.4 MW) turbines for a total capacity of 200 MW and the GEN-2016-022 Modification Request included a turbine change to 29 x Nordex N149 4.8 MW + 3 x Nordex N149 4.8 MW (Derated to 4.2 MW) turbines for a total capacity of 151.8 MW. In addition, the modification request also included changes to the collection system, the generator substation transformer and the generation interconnection line. The major modification request changes are shown in Figure 2-2, Table 2-1 and Table 2-2 below.

Figure 2-2: GEN-2015-034 & GEN-2016-022 Single Line Diagram (New Configuration)

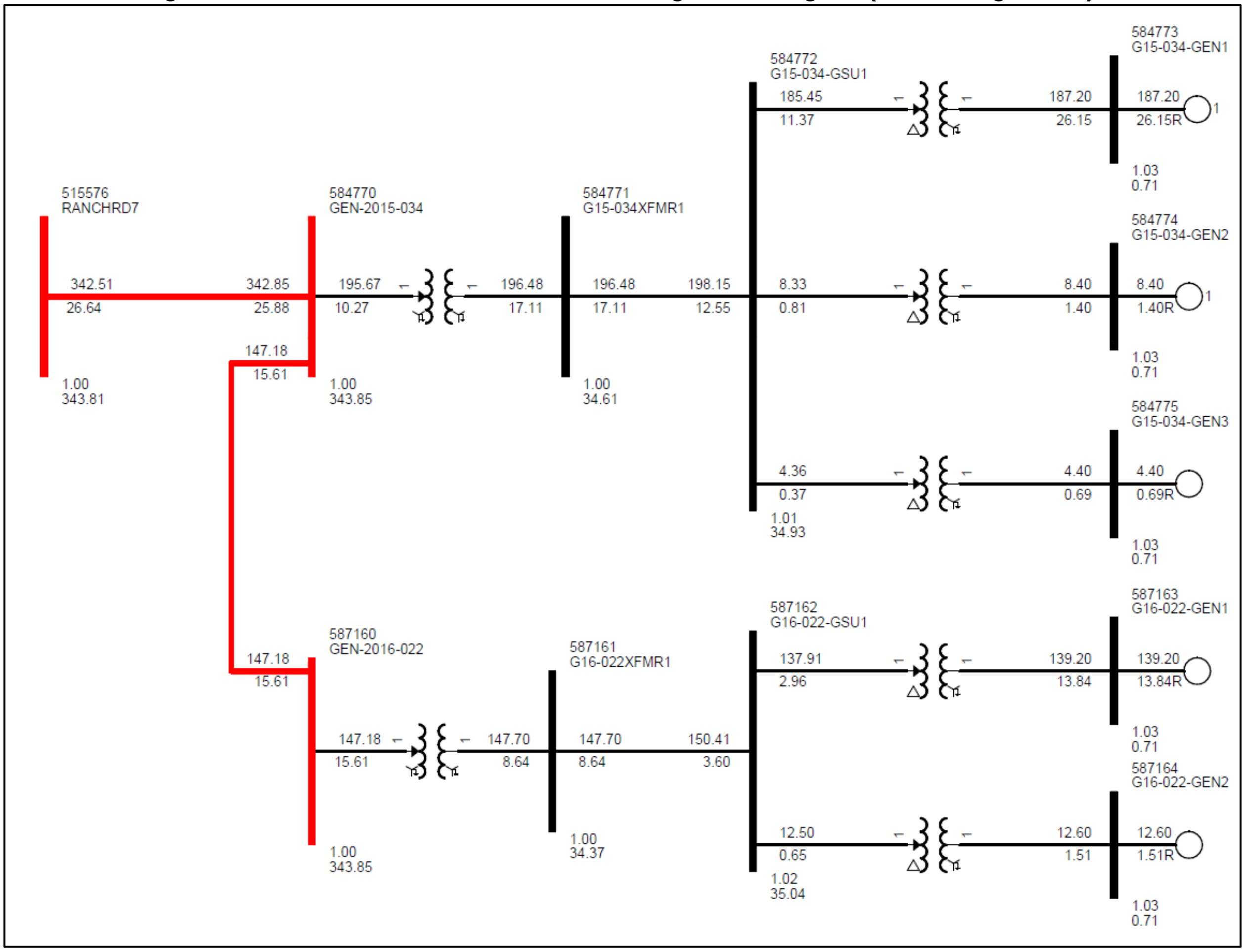


Table 2-1: GEN-2015-034 Modification Request

Facility	Existing	Modification Request
Point of Interconnection	Ranch Road 345 kV Substation (515576)	Ranch Road 345 kV Substation (515576)
Configuration/Capacity	57 x Vestas V136 GS 3.45MW (Gen 1) + 1 x Vestas V136 GS 3.35MW (Gen 2) = 200 MW	39 x Nordex N149 4.8 MW (Gen 1) + 2 x Nordex N149 4.8 MW (Derated to 4.2 MW) (Gen 2) + 1 x Nordex N149 4.8 MW (Derated to 4.4 MW) (Gen 3) = 200 MW
Generation Interconnection Line	Length = 5 miles R = 0.000260 pu X = 0.002380 pu B = 0.065180 pu	Length = 5 miles R = 0.000290 pu X = 0.003320 pu B = 0.032160 pu
Main Substation Transformer	Z = 9%, Winding 127 MVA, Rating A 169 MVA, Rating B 211 MVA	Z = 9%, Winding 127 MVA, Rating 211 MVA
GSU Transformer	Gen 1 Equivalent Qty: 57 Z = 9%, Rating 213.9 MVA Gen 2 Equivalent Qty: 1 Z = 9%, Rating 3.6 MVA	Gen 1 Equivalent Qty: 39 Z = 9.2%, Rating 208.65 MVA Gen 2 Equivalent Qty: 2 Z = 9.2%, Rating 10.7 MVA Gen 3 Equivalent Qty: 1 Z = 9.2%, Rating 5.35 MVA
Equivalent Collector Line	R = 0.003320 pu X = 0.003600 pu B = 0.051610 pu	R = 0.004326 pu X = 0.005666 pu B = 0.066370 pu

Table 2-2: GEN-2016-022 Modification Request

Facility	Existing	Modification Request
Point of Interconnection	Ranch Road 345 kV Substation (515576)	Ranch Road 345 kV Substation (515576)
Configuration/Capacity	44 x Vestas V110 V126 GS 3.45 MW = 151.8 MW	29 x Nordex N149 4.8 MW (Gen 1) + 3 x Nordex N149 4.8 MW (Derated to 4.2 MW) (Gen 2) = 151.8 MW
Generation Interconnection Line	Length = 5 miles R = 0.000260 pu X = 0.002380 pu B = 0.065180 pu	Length = 5 miles (Shared with GEN-2015-034) R = 0.000290 pu X = 0.003320 pu B = 0.032160 pu
Main Substation Transformer	Z = 9%, Winding 100 MVA, Rating 166 MVA	Z = 11%, Winding 100 MVA, Rating 166 MVA
GSU Transformer	Equivalent Qty: 44 Z = 9%, Rating 165 MVA	Gen 1 Equivalent Qty: 29: Z = 9.2%, Rating 155.1 MVA Gen 2 Equivalent Qty: 3: Z = 9.2%, Rating 16 MVA
Equivalent Collector Line	R = 0.021550 pu X = 0.052740 pu B = 0.124130 pu	R = 0.012301 pu X = 0.018706 pu B = 0.090381 pu

3.0 Reactive Power Analysis

The reactive power analysis, also known as the low-wind/no-wind condition analysis, was performed for GEN-2015-034 and GEN-2016-022 to determine the reactive power contribution from the projects' interconnection line and collector transformers and cables during low/no wind conditions while the projects are still connected to the grid and to size shunt reactors that would reduce the projects' reactive power contributions to the POI to approximately zero.

3.1 Methodology and Criteria

For the GEN-2015-034 and GEN-2016-022 projects, the generators were switched out of service while other collector system elements remained in-service. A shunt reactor was first tested at the GEN-2015-034 collection substation 345 kV bus to set the MVAr flow into the POI to approximately zero while the GEN-2016-022 project was offline. With the size of the GEN-2015-034 project identified, the GEN-2016-022 collection system was switched back online to determine the shunt reactor required to reduce the MVAr flow into the POI to approximately zero.

3.2 Results

The results from the reactive power analysis showed that the GEN-2015-034 and GEN-2016-022 project required approximately 9.89 MVAr and 9.13 MVAr respectively for shunt reactance at the high side buses of each project substation, to reduce the POI MVAr to zero. This represents the contributions from the project collector systems. Figure 3-1 illustrates the shunt reactor sizes required to reduce the POI MVAr flow to approximately zero. Reactive compensation can be provided either by discrete reactive devices or by the generator itself if it possesses that capability.

Figure 3-1: GEN-2015-034 & GEN-2016-022 Single Line Diagram (Shunt Reactor)

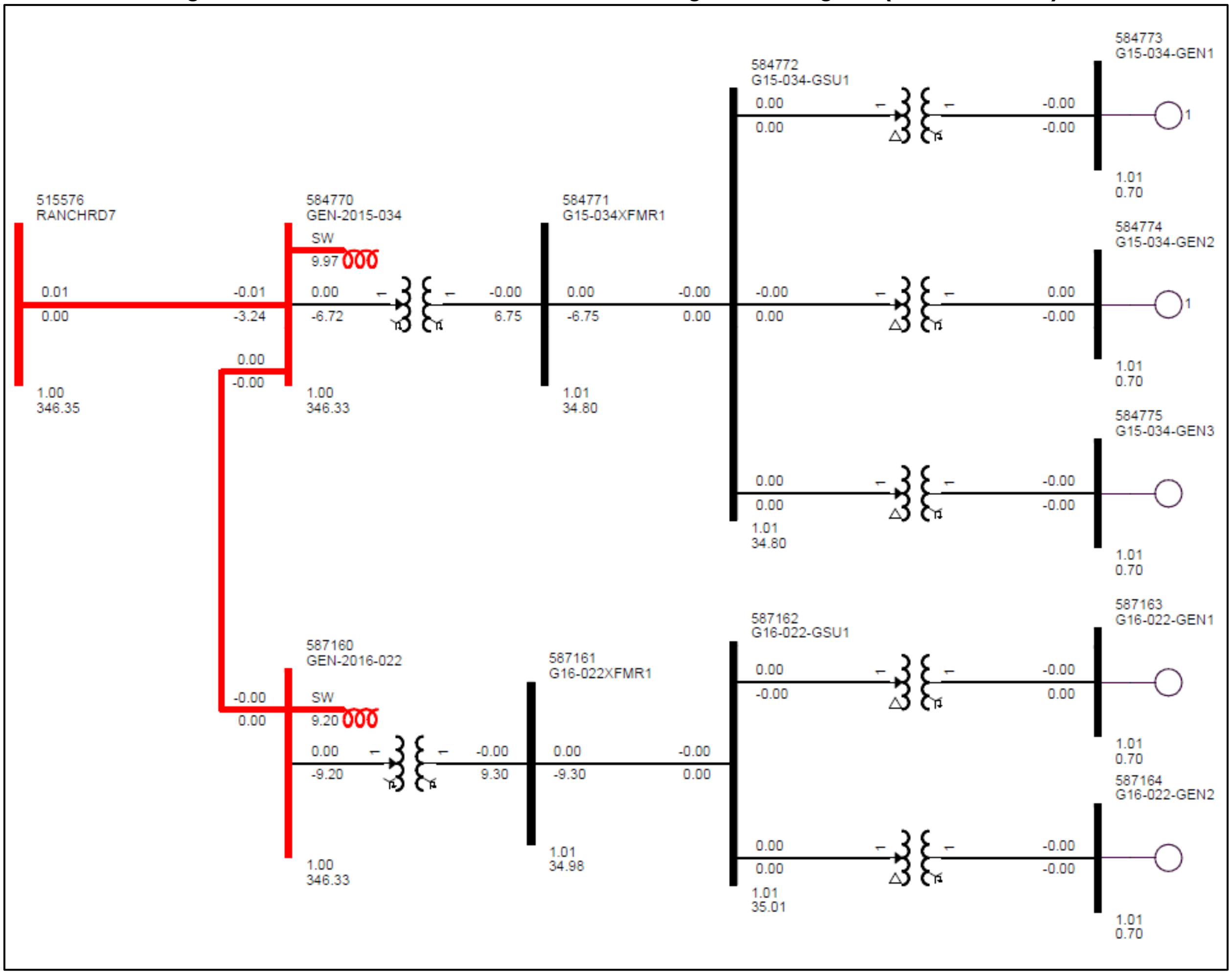


Table 3-1 shows the shunt reactor sizes determined for GEN-2015-034 and GEN-2016-022 in the three study models used in the assessment.

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

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)		
			17WP	18SP	26SP
GEN-2015-034	515576	Ranch Road 345 kV Substation	9.89	9.89	9.89
GEN-2016-022	515576	Ranch Road 345 kV Substation	9.13	9.13	9.13

4.0 Short Circuit Analysis

A short-circuit study was performed on the power flow models for the 2018SP and 2026SP models for GEN-2015-034 and GEN-2016-022 using the modified study models. The detail results of the short-circuit analysis are provided in Appendix A.

4.1 Methodology

The short-circuit analysis included applying a 3-phase fault on buses up to 5 levels away from the 345 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.

4.2 Results

The results of the short circuit analysis for the 2018SP and 2026SP models are summarized in Table 4-1 and Table 4-2 respectively. The maximum increase in fault current was about 6.7% and 0.85 kA. The maximum fault current calculated within 5 buses of the GEN-2015-034 and GEN-2016-022 POI was less than 45 kA and 44 kA for the 2018SP and 2026SP models respectively.

Table 4-1: 2018SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	16.1	0.00	0.0%
138	44.1	0.05	0.2%
345	32.8	0.85	6.7%
Max	**44.1**	**0.85**	**6.7%**

Table 4-2: 2026SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	18.9	0.00	0.0%
138	43.7	0.05	0.2%
345	32.7	0.85	6.7%
Max	**43.7**	**0.85**	**6.7%**

5.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the turbine changes and other modifications to the GEN-2015-034 and GEN-2016-022 projects. The analysis was performed according to SPP's Disturbance Performance Requirements shown in Appendix B. The modification details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix C. The simulation plots can be found in Appendix D.

5.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested 39 x Nordex N149 4.8 MW + 2 x Nordex N149 4.8 MW (Derated to 4.2 MW) + 1 x Nordex N149 4.8 MW (Derated to 4.4 MW) turbines for GEN-2015-034 and 29 x Nordex N149 4.8 MW + 3 x Nordex N149 4.8 MW (Derated to 4.2 MW) turbines for the GEN-2016-022. This stability analysis was performed using PTI's PSS/E version 33.7 software. The Nordex User Defined Model (UDM) NXK8BJ_WTG_V6_r33.dll and NXWFC_R02_V2_44_r33.dll were used as the turbine model and plant controller model, respectively.

The stability models were developed using the models from the DISIS-2016-002 ReStudy #1 (DISIS-2016-002-1) for Group 8 including network upgrades identified in that restudy. The modifications requested to projects GEN-2015-034 and GEN-2016-022 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-2016-002-1 (Group 8) request, GEN-2015-034 and GEN-2016-022 is provided in Appendix C.

During the fault simulations, the active power (PELEC), reactive power (QELEC) and terminal voltage (ETERM) were monitored for GEN-2015-034 and GEN-2016-022 and other equally and prior queued projects in Group 8. In addition, voltages of five (5) buses away from the POI of GEN-2015-034 and GEN-2016-022 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.

5.2 Fault Definitions

Aneden selected the fault events simulated specifically for GEN-2015-034 and GEN-2016-022 in the DISIS-2016-002-1 Group 8 study 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 5-1 below. These contingencies were applied to the modified 2017 Winter Peak, 2018 Summer Peak, and the 2026 Summer Peak models.

Table 5-1: Fault Definitions

Fault ID	Fault Descriptions
FLT33-3PH	3 Phase Fault on RANCHRD7 (515576) to OPENSKY7 (515621) 345.0 kV Line circuit 1 near RANCHRD7 (515576) a. Apply three-phase fault at RANCHRD7 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.
FLT34-3PH	3 Phase Fault on OPENSKY7 (515621) to G15-052T (560053) 345.0 kV Line circuit 1 near OPENSKY7 (515621) a. Apply three-phase fault at OPENSKY7 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.
FLT35-3PH	3 Phase Fault on RANCHRD7 (515576) to SOONER 7 (514803) 345.0 kV Line circuit 1 near RANCHRD7 (515576) a. Apply three-phase fault at RANCHRD7 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.
FLT36-3PH	3 Phase Fault on SOONER 7 (514803) to G15-066T (560056) 345.0 kV Line circuit 1 near SOONER 7 (514803) a. Apply three-phase fault at SOONER 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.
FLT38-3PH	3 Phase Fault on SOONER 7 (514803) to G15-066T (560056) 345.0 kV Line circuit 1 near SOONER 7 (514803) a. Apply three-phase fault at SOONER 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.
FLT39-3PH	3 Phase Fault on SOONER 7 (514803) to G16-061-TAP (560084) 345.0 kV Line circuit 1 near SOONER 7 (514803) a. Apply three-phase fault at SOONER 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.
FLT40-3PH	3 Phase Fault on G16-061-TAP (560084) to SOONER 7 (514803) 345.0 kV Line circuit 1 near G16-061-TAP (560084) a. Apply three-phase fault at G16-061-TAP 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.
FLT41-3PH	3 Phase Fault on SOONER 7 (514803) 345.0 kV /SOONER 4 (514802) 138.0 kV / SOONER 1 (515760) 13.8 kV Transformer #1 near SOONER 7 (514803) a. Apply three-phase fault at SOONER 7 345.0 kV bus b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT80-3PH	3 phase fault on the SOONER (514803) to RANCH ROAD (515576) 345kV line, near Sooner. a. Apply fault at the SOONER 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT81-3PH	3 Phase Fault on SPRNGCK7 (514881) to NORTWST7 (514880) 345.0 kV Line circuit 1 near SPRNGCK7 (514881) a. Apply three-phase fault at SPRNGCK7 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.

Table 5-1 continued

Fault ID	Fault Descriptions
FLT82-3PH	3 phase fault on the G15-066T (560056) to Cleveland (512694) 345kV line, near G15-066T. a. Apply fault at the G15-066T 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT83-3PH	3 Phase Fault on G16-061-TAP (560084) to WOODRNG7 (514715) 345.0 kV Line circuit 1 near G16-061-TAP (560084) a. Apply three-phase fault at G16-061-TAP 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.
FLT9001-3PH	3 Phase Fault on SOONER 7 (514803) 345.0 kV / SOONER2G (514806) 20.0 kV Transformer circuit 1 near SOONER 7 (514803) a. Apply three-phase fault at SOONER 7 345.0 kV bus b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT9002-3PH	3 Phase Fault on SOONER 7 (514803) to GEN-2015-030 (584690) 345.0 kV Line circuit 1 near SOONER 7 (514803) a. Apply three-phase fault at SOONER 7 345.0 kV bus b. Clear fault after 5 cycles by tripping the faulted line. Trip generator 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 SOONER 7 (514803) to THUNDER7 (515894) 345.0 kV Line circuit 1 near SOONER 7 (514803) a. Apply three-phase fault at SOONER 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.
FLT9004-3PH	3 Phase Fault on OPENSKY7 (515621) to KAYWIND7 (514825) 345.0 kV Line circuit 1 near OPENSKY7 (515621) a. Apply three-phase fault at OPENSKY7 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.
FLT9005-3PH	3 Phase Fault on SPRNGCK7 (514881) 345.0 kV / SPGCK1&2 (514882) 13.8 kV Transformer circuit 1 near SPRNGCK7 (514881) a. Apply three-phase fault at SPRNGCK7 345.0 kV bus b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT9006-3PH	3 Phase Fault on SOONER 7 (514803) to G16-100-TAP (587804) 345.0 kV Line circuit 1 near SOONER 7 (514803) a. Apply three-phase fault at SOONER 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 G15-052T (560053) to GEN-2015-052 (584900) 345.0 kV Line circuit 1 near G15-052T (560053) a. Apply three-phase fault at G15-052T 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 G16-061-TAP (560084) to GEN-2016-061 (587410) 345.0 kV Line circuit 1 near G16-061-TAP (560084) a. Apply three-phase fault at G16-061-TAP 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 G15-066T (560056) to GEN-2015-066 (585040) 345.0 kV Line circuit 1 near G15-066T (560056) a. Apply three-phase fault at G15-066T 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.

Table 5-1 continued

Fault ID	Fault Descriptions
FLT9010-3PH	3 Phase Fault on RANCHRD7 (515576) to OMCDLEC7 (529200) 345.0 kV Line circuit 1 near RANCHRD7 (515576) a. Apply three-phase fault at RANCHRD7 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 RANCHRD7 (515576) to FRNTWND7 (515688) 345.0 kV Line circuit 1 near RANCHRD7 (515576) a. Apply three-phase fault at RANCHRD7 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.
FLT9012-3PH	3 Phase Fault on SOONER 4 (514802) to SNRPMPT4 (514798) 138.0 kV Line circuit 1 near SOONER 4 (514802) a. Apply three-phase fault at SOONER 4 138.0 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.
FLT9013-3PH	3 Phase Fault on SOONER 4 (514802) to PERRY 4 (514707) 138.0 kV Line circuit 1 near SOONER 4 (514802) a. Apply three-phase fault at SOONER 4 138.0 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 SOONER 4 (514802) to MILLERT4 (514704) 138.0 kV Line circuit 1 near SOONER 4 (514802) a. Apply three-phase fault at SOONER 4 138.0 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 SOONER 4 (514802) to MORISNT4 (515447) 138.0 kV Line circuit 1 near SOONER 4 (514802) a. Apply three-phase fault at SOONER 4 138.0 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 the CLEVLND7 (512694) to T.NO.--7 (509852) 345 kV line circuit 1, near CLEVLND7. a. Apply fault at the CLEVLND7 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9017-3PH	3 phase fault on the CLEVLND7 (512694) 345 kV / (512729) 138 kV /(512817) 13.8 kV transformer, near CLEVLND7 345 kV. a. Apply fault at the CLEVLND7 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT9018-3PH	3 Phase Fault on G16-100-TAP (587804) to GEN-2016-100 (587800) 345.0 kV Line circuit 1 near G16-100-TAP (587804) a. Apply three-phase fault at G16-100-TAP (587804) 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.
FLT9019-3PH	3 Phase Fault on G16-100-TAP (587804) to GEN-2016-119 (587950) 345.0 kV Line circuit 1 near G16-100-TAP (587804) a. Apply three-phase fault at G16-100-TAP (587804) 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.
FLT9020-3PH	3 Phase Fault on G16-100-TAP (587804) to SPRNGCK7 (514881) 345.0 kV Line circuit 1 near G16-100-TAP (587804) a. Apply three-phase fault at G16-100-TAP (587804) 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.

Table 5-1 continued

Fault ID	Fault Descriptions
FLT42-SB	Stuck Breaker on Ranch Road – Open Sky 345kV circuit 1 line a. Apply single-phase fault at Open Sky (515621) on the 345kV bus. b. After 16 cycles, trip the Open Sky (515621) – Ranch Road (515576) 345kV circuit 1 line c. Trip the Open Sky (515621) – G15-052T (560053) 345kV circuit 1 line, and remove the fault, Kay wind generators isolated from the grid and tripped
FLT44-SB	Stuck Breaker on Sooner – Spring Creek 345kV circuit 1 line a. Apply single-phase fault at Sooner (514803) on the 345kV bus. b. After 16 cycles, trip the Sooner (514803) – G16-100 TAP (587804) 345kV circuit 1 line c. Trip the Sooner (514803) – Ranch Road (515576) 345kV circuit 1 line, and remove the fault
FLT45-SB	Stuck Breaker on Sooner – G15-066T 345kV circuit 1 line a. Apply single-phase fault at Sooner (514803) on the 345kV bus. b. After 16 cycles, trip the Sooner (514803) – G15-066T (560056) 345kV circuit 1 line c. Trip the Sooner (514803) – Ranch Road (515576) 345kV circuit 1 line, and remove the fault
FLT46-SB	Stuck Breaker on Sooner – G15-066T 345kV circuit 1 line a. Apply single-phase fault at Sooner (514803) on the 345kV bus. b. After 16 cycles, trip the Sooner (514803) – G15-066T (560056) 345kV circuit 1 line c. Trip the Sooner (514803) – G16-061-Tap (560084) 345kV circuit 1 line, and remove the fault
FLT1001-SB	Stuck Breaker Single Phase Fault on SOONER 7 (514803) to RANCHRD7 (515576) 345.0 kV Line circuit 1 near SOONER 7 (514803), backup clear by SOONER 7 (514803) to G16-061-TAP (560084) 345.0 kV Line circuit 1 a. Apply single-phase fault at SOONER 7 345.0 kV bus b. Wait for 16 cycles then open SOONER 7 (514803) to RANCHRD7 (515576) 345.0 kV Line circuit 1 c. Trip SOONER 7 (514803) to G16-061-TAP (560084) 345.0 kV Line circuit 1 and remove the fault
FLT1002-SB	Stuck Breaker on Sooner – G16061 Tap kV line "a. Apply single-phase fault at Sooner (514803) 345 kV bus on the Sooner – G16061 Tap (560084) 345 kV line" b. After 16 cycles, trip the Sooner (514803) – G16-100 TAP (587804) 345 kV line c. Trip the Sooner– – G16061 Tap (560084) line, and remove the fault
FLT1003-SB	Stuck Breaker on Sooner 138 kV/345 kV/13.8 kV transformer a. Apply single-phase fault at the Sooner 138 kV (514802) b. After 16 cycles, trip the Sooner – MORISNT4 (515447) 138 kV line c. Trip the Sooner 138 kV (514802)/345 kV (514803)/13.8 kV (515760) transformer, and remove the fault
FLT1004-SB	Stuck Breaker on Sooner - MILLERT4 138 kV line a. Apply single-phase fault at Sooner (514802) 138 kV b. After 16 cycles, trip the Sooner (514802) - SNRPMPT4 (514798) 138 kV line c. Trip the Sooner - MILLERT4 (514704) 138 kV line, and remove the fault
FLT1005-SB	Stuck Breaker on Ranch Road 7 – Open Sky 7 345 kV line a. Apply single-phase fault at Ranch Road 7 (515576) 345 kV b. After 20 cycles, trip the Ranch Road 7 (515576) – Omcdlec 7 (529200) 345 kV line c. Trip the Ranch Road 7 (515576) – Open Sky 7 (515621) 345 kV line, and remove the fault
FLT1006-SB	Stuck Breaker on Cleveland 345/138/13.8 kV circuit 1 transformer a. Apply single-phase fault at Cleveland 7 (512694) on the 345 kV bus. b. After 20 cycles, trip the Cleveland 7 (512694) – T.NO.--7 (509852) 345 kV line "c. Trip the Cleveland 7 (512694) 345/(512729) 138/(512817) 13.8 kV transformer circuit 1, and remove the fault"

Table 5-1 continued

Fault ID	Fault Descriptions
FLT33-PO1	Prior outage of the Rose Hill (532794) – G15-052T (560053) 345kV line 3 phase fault on the Ranch Road (515576) – Open Sky (515621) 345kV line, near Ranch Road. a. Apply fault at the Ranch Road 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. Trip Kay wind, G15-052, FRNTWD, OMCDLEC c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT38-PO1	"Prior outage of the Rose Hill (532794) – G15-052T (560053) 345kV line 3 Phase Fault on SOONER 7 (514803) to G15-066T (560056) 345.0 kV Line circuit 1 near SOONER 7 (514803)" a. Apply three-phase fault at SOONER 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.
FLT39-PO1	"Prior outage of the Rose Hill (532794) – G15-052T (560053) 345kV line 3 Phase Fault on SOONER 7 (514803) to G16-061-TAP (560084) 345.0 kV Line circuit 1 near SOONER 7 (514803)" a. Apply three-phase fault at SOONER 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.
FLT41-PO1	"Prior outage of the Rose Hill (532794) – G15-052T (560053) 345kV line 3 Phase Fault on SOONER 7 (514803) 345.0 kV /SOONER 4 (514802) 138.0 kV / SOONER 1 (515760) 13.8 kV Transformer #1 near SOONER 7 (514803)" a. Apply three-phase fault at SOONER 7 345.0 kV bus b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT9001-PO1	"Prior outage of the Rose Hill (532794) – G15-052T (560053) 345kV line 3 Phase Fault on SOONER 7 (514803) 345.0 kV / SOONER2G (514806) 20.0 kV Transformer circuit 1 near SOONER 7 (514803)" a. Apply three-phase fault at SOONER 7 345.0 kV bus b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT9002-PO1	"Prior outage of the Rose Hill (532794) – G15-052T (560053) 345kV line 3 Phase Fault on SOONER 7 (514803) to GEN-2015-030 (584690) 345.0 kV Line circuit 1 near SOONER 7 (514803)" a. Apply three-phase fault at SOONER 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.
FLT9003-PO1	"Prior outage of the Rose Hill (532794) – G15-052T (560053) 345kV line 3 Phase Fault on SOONER 7 (514803) to THUNDER7 (515894) 345.0 kV Line circuit 1 near SOONER 7 (514803)" a. Apply three-phase fault at SOONER 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.
FLT9006-PO1	"Prior outage of the Rose Hill (532794) – G15-052T (560053) 345kV line 3 Phase Fault on SOONER 7 (514803) to G16-100-TAP (587804) 345.0 kV Line circuit 1 near SOONER 7 (514803)" a. Apply three-phase fault at SOONER 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.
FLT33-PO2	Prior outage of the Sooner (514803) – G15-066T (560056) 345kV line 3 phase fault on the Ranch Road (515576) – Open Sky (515621) 345kV line, near Ranch Road. a. Apply fault at the Ranch Road 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT35-PO2	Prior outage of the Sooner (514803) – G15-066T (560056) 345kV line 3 phase fault on the Ranch Road (515576) – Sooner (514803) 345kV line, near Ranch Road. a. Apply fault at the Ranch Road 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 5-1 continued

Fault ID	Fault Descriptions
FLT39-PO2	Prior outage of the Sooner (514803) – G15-066T (560056) 345kV line 3 phase fault on the Sooner (514803) – G16-061-Tap (560084) 345kV line, near Sooner. a. Apply fault at the Sooner 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT41-PO3	Prior outage of the Sooner (514803) – Ranch Road (515576) 345kV line 3 phase fault on the Sooner 345/138/13.8kV (514803/514802/515760) transformer, near Sooner. a. Apply fault at the Sooner 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer and remove fault.
FLT9021-PO3	"Prior Outage of RANCHRD7 (515576) to SOONER 7 (514803) 345.0 kV Line circuit 1 3 phase fault on Rose Hill (532794) to Lathams (532800) 345kV line, near Rose Hill" a. Apply three-phase fault at G16-100-TAP (587804) 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.
FLT9022-PO3	"Prior Outage of RANCHRD7 (515576) to SOONER 7 (514803) 345.0 kV Line circuit 1 3 phase fault on the Rose Hill (532794) to Benton (532791) 345kV line, near Rose Hill" a. Apply fault at the Rose Hill 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9023-PO3	"Prior Outage of RANCHRD7 (515576) to SOONER 7 (514803) 345.0 kV Line circuit 1 3 phase fault on the Rose Hill (532794) to Wolf Creek (532797) 345kV line, near Rose Hill" a. Apply fault at the Rose Hill 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9024-PO3	"Prior Outage of RANCHRD7 (515576) to SOONER 7 (514803) 345.0 kV Line circuit 1 3 Phase Fault on Rose Hill (532794) 345.0 kV / (533062) 138kV / (532826) 13.8 kV Transformer circuit 1 near Rose Hill (532794)" a. Apply three-phase fault at Rose Hill 345.0 kV bus b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT38-PO4	"Prior Outage of RANCHRD7 (515576) to OPENSKY7 (515621) 345.0 kV Line circuit 1 3 Phase Fault on SOONER 7 (514803) to G15-066T (560056) 345.0 kV Line circuit 1 near SOONER 7 (514803)" a. Apply three-phase fault at SOONER 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.
FLT39-PO4	"Prior Outage of RANCHRD7 (515576) to OPENSKY7 (515621) 345.0 kV Line circuit 1 3 Phase Fault on SOONER 7 (514803) to G16-061-TAP (560084) 345.0 kV Line circuit 1 near SOONER 7 (514803)" a. Apply three-phase fault at SOONER 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.
FLT41-PO4	"Prior Outage of RANCHRD7 (515576) to OPENSKY7 (515621) 345.0 kV Line circuit 1 3 Phase Fault on SOONER 7 (514803) 345.0 kV /SOONER 4 (514802) 138.0 kV / SOONER 1 (515760) 13.8 kV Transformer #1 near SOONER 7 (514803)" a. Apply three-phase fault at SOONER 7 345.0 kV bus b. Clear fault after 5 cycles by tripping the faulted transformer.
FLT9001-PO4	"Prior Outage of RANCHRD7 (515576) to OPENSKY7 (515621) 345.0 kV Line circuit 1 3 Phase Fault on SOONER 7 (514803) 345.0 kV / SOONER2G (514806) 20.0 kV Transformer circuit 1 near SOONER 7 (514803)" a. Apply three-phase fault at SOONER 7 345.0 kV bus b. Clear fault after 5 cycles by tripping the faulted transformer.

Table 5-1 continued

Fault ID	Fault Descriptions
FLT9002-PO4	"Prior Outage of RANCHRD7 (515576) to OPENSKY7 (515621) 345.0 kV Line circuit 1 3 Phase Fault on SOONER 7 (514803) to GEN-2015-030 (584690) 345.0 kV Line circuit 1 near SOONER 7 (514803)" a. Apply three-phase fault at SOONER 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.
FLT9003-PO4	"Prior Outage of RANCHRD7 (515576) to OPENSKY7 (515621) 345.0 kV Line circuit 1 3 Phase Fault on SOONER 7 (514803) to THUNDER7 (515894) 345.0 kV Line circuit 1 near SOONER 7 (514803)" a. Apply three-phase fault at SOONER 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.
FLT9006-PO4	"Prior Outage of RANCHRD7 (515576) to OPENSKY7 (515621) 345.0 kV Line circuit 1 3 Phase Fault on SOONER 7 (514803) to G16-100-TAP (587804) 345.0 kV Line circuit 1 near SOONER 7 (514803)" a. Apply three-phase fault at SOONER 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.

5.3 Results

There were no damping or voltage recovery violations observed during the simulations and the system returned to stable conditions for all the simualted faults that were associated with the modification request.

Table 5-2 shows the results of the fault events simulated for each of the models. The associated stability plots are provided in Appendix D. 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 5-2: GEN-2015-034 and GEN-2016-022 Dynamic Stability Results

Fault ID	17WP			18SP			26SP		
	Volt. Recov.	Volt. Vio.	Stability	Volt. Recov.	Volt. Vio.	Stability	Volt. Recov.	Volt. Vio.	Stability
FLT33-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT34-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT35-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT36-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT38-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT39-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT40-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT41-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
LT80-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT81-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT82-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT83-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 5-2 continued

Fault ID	17WP			18SP			26SP		
	Volt. Recov.	Volt. Vio.	Stability	Volt. Recov.	Volt. Vio.	Stability	Volt. Recov.	Volt. Vio.	Stability
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT42-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT44-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT45-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT46-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT33-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT38-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT39-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT41-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT33-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT35-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT39-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT41-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT38-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT39-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT41-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 5-2 continued

Fault ID	17W			18S			26S		
	Volt. Recov.	Volt. Vio.	Stability	Volt. Recov.	Volt. Vio.	Stability	Volt. Recov.	Volt. Vio.	Stability
FLT9001-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

6.0 Conclusions

The Interconnection Customer requested a Modification Request Impact Study to assess the impact of the turbine and facility changes to the GEN-2015-034 and GEN-2016-022 which have the same point of interconnection at the Ranch Road 345 kV substation. The changes to GEN-2015-034 include a new configuration with a total of 39 x Nordex N149 4.8 MW + 2 x Nordex N149 4.8 MW (Derated to 4.2 MW) + 1 x Nordex N149 4.8 MW (Derated to 4.4 MW) wind turbines for a total capacity of 200 MW and 29 x Nordex N149 4.8 MW + 3 x Nordex N149 4.8 MW (Derated to 4.2 MW) wind turbines for a total capacity of 151.8MW for GEN-2016-022. In addition, the modification request included changes to the collection systems and the generator substation transformers.

A power factor analysis was not performed as there was no change in the point of interconnection for GEN-2015-034 and GEN-2016-022.

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-2015-034 and GEN-2016-022 project may require a 9.89 MVAr and 9.13 MVAr sized shunt reactors on the 345 kV bus of the respective project substations. The shunt reactors are needed to reduce the reactive power flow 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-2015-034 and GEN-2016-022 was 0.85 kA. The largest fault current calculated was below 45 kA and 44 kA in the 2018SP and 2026SP models respectively.

The results of the dynamic stability analysis showed that there were no damping or voltage recovery violations observed during the simulations and the system returned to stable conditions for all the simulated faults. Additionally, the project generators were 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-2015-034 and GEN-2016-022 Modification Request does not constitute a material modification.