Submitted to
Southwest Power Pool

SPP Southwest Power Pool

Report On

GEN-2015-088
Modification Request Impact Study

Revision R1

Date of Submittal
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anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
11/19/2020	Aneden Consulting	Initial Report Issued.

Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2015-088, an active generation interconnection request with a point of interconnection (POI) at the G15-088-TAP (aka Tobias 345 kV) bus on the Moore to Pauline 345 kV line.

The GEN-2015-088 project is interconnected in the Nebraska Public Power District (NPPD) control area with a capacity of 300 MW as shown in Table ES-1 below. This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2015-088 from the previously studied 150 x Vestas V100 2.0 MW to a turbine configuration of 36 x Siemens Gamesa 2.7-129 2.75 MW + 30 x Siemens Gamesa 145 4.5 MW + 33 x Vestas V110 2.0 MW wind turbines for total capacity of 300 MW. In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformer, and the generation interconnection line. The modification request changes are shown in Table ES-2.

Table ES-1: GEN-2015-088 Existing Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2015-088	300	150 x Vestas V100 2.0 MW = 300 MW	Tap on Moore (640277) to Pauline (640312) 345 kV (G15-088-TAP [aka Tobias 345 kV] 560062)

Table ES-2: GEN-2015-088 Modification Request

<table>
<tr><th>Facility</th><th colspan="2">Existing</th><th colspan="4">Modification</th></tr>
<tr><td>Point of Interconnection</td><td colspan="2">Tap on Moore (640277) to Pauline (640312) 345 kV (G15-088-TAP [aka Tobias 345 kV] 560062)</td><td colspan="4">Tap on Moore (640277) to Pauline (640312) 345 kV (G15-088-TAP [aka Tobias 345 kV] 560062)</td></tr>
<tr><td>Configuration/Capacity</td><td colspan="2">150 x Vestas V100 2.0 MW = 300 MW</td><td colspan="4">36 x Siemens Gamesa 2.7-129 2.75 MW + 30 x Siemens Gamesa 145 4.5 MW + 33 x Vestas V110 2.0 MW (MK10C) = 300 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td colspan="2">Length = 2.5 miles
R = 0.000148 pu
X = 0.000758 pu
B = 0.045679 pu</td><td colspan="2">G15-088-TAP (POI) - GEN-2015-088
Length = 0.075 miles
R = 0.000000 pu
X = 0.000003 pu
B = 0.000050 pu</td><td colspan="2">GEN-2015-088 - GEN-2015-088 (345 kV MPT Bus)
Length = 0.155 miles
R = 0.000001 pu
X = 0.000012 pu
B = 0.000217 pu</td></tr>
<tr><td>Main Substation Transformer</td><td>X = 10.5%, R = 0.42%, Winding 100 MVA, Rate 167 MVA</td><td>X = 10.5%, R = 0.42%, Winding 100 MVA, Rate 167 MVA</td><td colspan="2">X12 = 9.0%, R12 = 0.142%, X23 = 4.5%, R23 = 0.071%, X13 = 13.5%, R13 = 0.213% Winding 120 MVA, Rating 200 MVA</td><td colspan="2">X12 = 9.0%, R12 = 0.142%, X23 = 4.5%, R23 = 0.071%, X13 = 13.5%, R13 = 0.213% Winding 120 MVA, Rating 200 MVA</td></tr>
<tr><td>GSU Transformer</td><td colspan="2">Gen 1 Equivalent Qty: 150
X = 9.0%, R = 0.80%, Rating 315 MVA</td><td>Gen 1 Equivalent Qty: 36
X = 8.38%, R = 0.53%, Rating 126 MVA</td><td>Gen 2 Equivalent Qty: 10
X = 8.74%, R = 0.67%, Winding 39 MVA, Rating 55 MVA</td><td>Gen 3 Equivalent Qty: 20
X = 8.74%, R = 0.67%, Winding 78 MVA, Rating 110 MVA</td><td>Gen 4 Equivalent Qty: 33
X = 9.76%, R = 0.895%, Rating 75.9 MVA</td></tr>
<tr><td>Equivalent Collector Line 1 (connected to GSU bus)</td><td colspan="2">R = 0.005440 pu
X = 0.008940 pu
B = 0.219770 pu</td><td>R = 0.010643 pu
X = 0.014663 pu
B = 0.071318 pu</td><td>R = 0.035243 pu
X = 0.054081 pu
B = 0.037362 pu</td><td>R = 0.017746 pu
X = 0.025872 pu
B = 0.075142 pu</td><td>R = 0.020890 pu
X = 0.023283 pu
B = 0.047921 pu</td></tr>
</table>

Table ES-2 continued

Facility	Existing	Modification			
Equivalent Collector Line 2 (connected to MPT bus)	N/A	R = 0.000000 pu X = 0.000200 pu B = 0.000000 pu	R = 0.000000 pu X = 0.000200 pu B = 0.000000 pu	R = 0.000000 pu X = 0.000200 pu B = 0.000000 pu	R = 0.000000 pu X = 0.000200 pu B = 0.000000 pu

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.83%. However, SPP determined that the turbine change from Vestas to a combination of Vestas and Siemens Gamesa turbines required short circuit and dynamic stability analyses.

The scope of this modification request study included a charging current compensation analysis, short circuit analysis, and dynamic stability analysis.

Aneden performed the analyses using the modification request data based on the DISIS-2016-002-2 Group 9 study models:

1. 2017 Winter Peak (2017WP),
2. 2018 Summer Peak (2018SP),
3. 2026 Summer Peak (2026SP),
4. 2017 GGS Winter Peak Case (2017WP_GGS),
5. 2018 GGS Summer Peak Case (2018SP_GGS), and
6. 2026 GGS Summer Peak Case (2026SP_GGS).

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

The results of the charging current compensation analysis performed using the 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak models showed that the GEN-2015-088 project needed 23.4 MVAr of reactor shunts on the 34.5 kV bus of the project substation, an increase from the 22.2 MVAr found in the previous DISIS study[1]. 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 or no-wind conditions. The information gathered from the charging current compensation analysis is provided as information to the customer and Transmission Owner. SPP does not require additional reactive requirements based on the results of this analysis.

The results from the short circuit analysis with the updated topology showed that the maximum GEN-2015-088 contribution to three-phase fault currents in the immediate systems at or near GEN-2015-088 was not greater than 0.96 kA for the 2018SP and 2026SP models and 0.94 kA for the 2018SP and 2026SP GGS models. All three-phase fault current levels within 5 buses of the POI with the GEN-2015-088 generators online were below 43 kA for the 2018SP and 2026SP models, as well as the 2018SP and 2026SP GGS models.

[1] Definitive Interconnection System Impact Study for Generation Interconnection Requests (DISIS-2015-002-1) – August 2016

The dynamic stability analysis was performed using the six DISIS-2016-002-2 models 2017 Winter Peak, 2018 Summer Peak, 2026 Summer Peak, 2017 Winter Peak GGS, 2018 Summer Peak GGS, and 2026 Summer Peak GGS. Up to 58 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

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

The requested modification has been determined by SPP to not be a Material Modification. The requested modification does not have a material impact on the cost or timing of any Interconnection Request with a later Queue priority date.

In accordance with FERC Order No. 827, the generating facility will be required to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation.

It is likely that the customer may be required to reduce its generation output to 0 MW in real-time, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Nothing in this study should be construed as a guarantee of transmission service or delivery rights. If the customer wishes to obtain deliverability to final customers, a separate request for transmission service must be requested on Southwest Power Pool’s OASIS by the customer.

1.0 Scope of Study

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2015-088. A Modification Request Impact Study is a generation interconnection study performed to evaluate the impacts of modifying the DISIS study assumptions. The determination of the required scope of the study is dependent upon the specific modification requested and how it may impact the results of the DISIS study. Impacting the DISIS results could potentially affect the cost or timing of any Interconnection Request with a later Queue priority date, deeming the requested modification a Material Modification. The criteria sections below include reasoning as to why an analysis was either included or excluded from the scope of study.

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

1.1 Power Flow

To determine whether power flow analysis is required, SPP evaluates the difference in the real power output at the POI between the existing configuration and the requested modification. Power flow analysis is included if the difference has a significant impact on the results of DISIS study.

1.2 Stability Analysis, Short Circuit Analysis

To determine whether stability and short circuit analyses are required, SPP evaluates the difference between the turbine parameters and, if needed, the collector system impedance between the existing configuration and the requested modification. Dynamic stability analysis and short circuit analysis would be required if the differences listed above were determined to have a significant impact on the most recently performed DISIS stability analysis.

1.3 Charging Current Compensation Analysis

SPP requires that a charging current compensation analysis be performed on the requested modification configuration as it is a non-synchronous resource. The charging current compensation analysis determines the capacitive effect at the POI caused by the project's collector system and transmission line's capacitance. A shunt reactor size is determined in order to offset the capacitive effect and maintain zero (0) MVAr flow at the POI while the plant's generators and capacitors are offline.

1.4 Study Limitations

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

2.0 Project and Modification Request

The GEN-2015-088 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a point of interconnection (POI) at the G15-088-TAP (aka Tobias 345 kV) bus on the Moore to Pauline 345 kV line. At the time of the posting of this report, GEN-2015-088 is an active IR with a queue status of "IA FULLY EXECUTED/ON SCHEDULE." GEN-2015-088 is a wind farm, has a maximum summer and winter queue capacity of 300 MW, and has Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS).

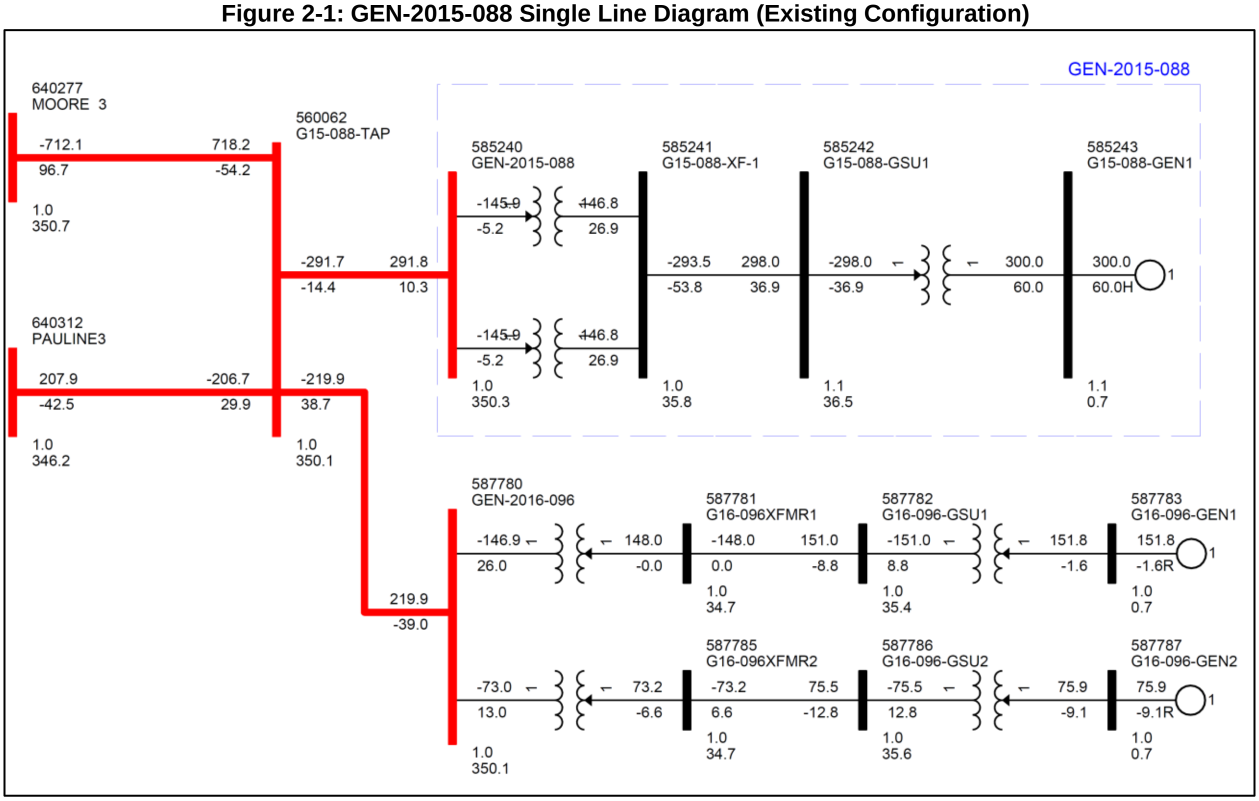
GEN-2015-088 was originally studied as part of Group 9 in the DISIS-2015-002 study. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2015-088 configuration.

The GEN-2015-088 project is proposed to interconnect in the Nebraska Public Power District (NPPD) control area with a combined nameplate capacity of 300 MW as shown in Table 2-1 below.

Table 2-1: GEN-2015-088 Existing Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2015-088	300	150 x Vestas V100 2.0 MW = 300 MW	Tap on Moore (640277) to Pauline (640312) 345 kV (G15-088-TAP [aka Tobias 345 kV] 560062)

Figure 2-1: GEN-2015-088 Single Line Diagram (Existing Configuration)



The GEN-2015-088 Modification Request included a turbine configuration change to a total of 36 x Siemens Gamesa 2.7-129 2.75 MW + 30 x Siemens Gamesa 145 4.5 MW + 33 x Vestas V110 2.0 MW wind turbines for total capacity of 300 MW. In addition, the modification request included changes to the collection system, generator substation transformer, main substation transformer, and generation interconnection line. The modification request changes are shown in Figure 2-2 and Table 2-2 below.

Figure 2-2: GEN-2015-088 Single Line Diagram (Modification Configuration)

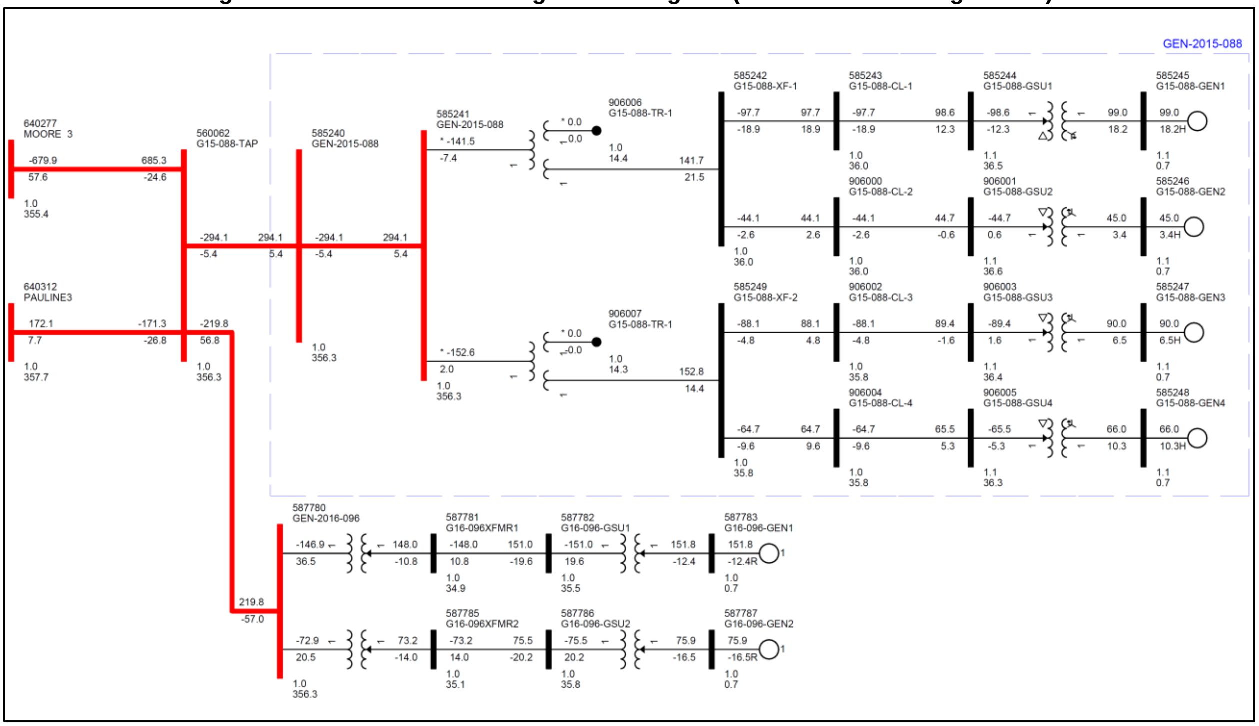


Table 2-2: GEN-2015-088 Modification Request

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Length = 0.075 miles
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Length = 0.155 miles
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<tr><td>Main Substation Transformer</td><td>X = 10.5%, R = 0.42%, Winding 100 MVA, Rate 167 MVA</td><td>X = 10.5%, R = 0.42%, Winding 100 MVA, Rate 167 MVA</td><td colspan="2">X12 = 9.0%, R12 = 0.142%, X23 = 4.5%, R23 = 0.071%, X13 = 13.5%, R13 = 0.213% Winding 120 MVA, Rating 200 MVA</td><td colspan="2">X12 = 9.0%, R12 = 0.142%, X23 = 4.5%, R23 = 0.071%, X13 = 13.5%, R13 = 0.213% Winding 120 MVA, Rating 200 MVA</td></tr>
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<tr><td>Equivalent Collector Line 2 (connected to MPT bus)</td><td colspan="2">N/A</td><td>R = 0.000000 pu
X = 0.000200 pu
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B = 0.000000 pu</td></tr>
</table>

3.0 Existing vs Modification Comparison

To determine which analysis is required, the differences between the existing configuration and the requested modification were evaluated.

Aneden performed this comparison and the resulting analyses using a set of modified study models developed based on the modification request data and the DISIS-2016-002-2 Group 9 study models.

The methodology and results of the comparisons are described below. The analysis was completed using PSS/E version 33.7 software.

3.1 POI Injection Comparison

The real power injection at the POI was determined using PSS/E for both the existing configuration and the requested modification with updates for GEN-2015-088. The percentage change in the POI injection before and after the modification request was then compared. If the MW difference was determined to be significant, power flow analysis would be performed to assess the impact of the modification request.

SPP determined that power flow analysis was not required due to the insignificant change (increase of 0.83%) in the real power output at the POI between the existing configuration and requested modification shown in Table 3-1.

Table 3-1: GEN-2015-088 POI Injection Comparison

Interconnection Request	Existing POI Injection from Project (MW)	MRIS POI Injection from Project (MW)	POI Injection Difference from Project %
GEN-2015-088	291.65	294.08	0.83%

3.2 Turbine Parameters Comparison

The turbine models from the existing configuration and the requested modification were compared to determine if the change in modeling parameters was significant.

For the turbine collection, the turbine changes were from Vestas turbines to a combination of Vestas and Siemens Gamesa turbines. SPP determined that short circuit analysis and dynamic stability analysis were required due to the change in turbines as the stability responses of the existing configuration and the requested modification's configuration may differ. The generator dynamic model for the modification can be found in Appendix A.

3.3 Equivalent Impedance Comparison Calculation

As the turbine comparison determined that short circuit and dynamic stability analyses were required, an equivalent impedance comparison was not needed for the determination of the scope of the study.

4.0 Charging Current Compensation Analysis

The charging current compensation analysis was performed for GEN-2015-088 to determine the capacitive charging effects during reduced generation conditions (unsuitable wind speeds, unsuitable solar irradiance, insufficient state of charge, idle conditions, curtailment, etc.) at the generation site and to size shunt reactors that would reduce the project reactive power contribution to the POI to approximately zero.

4.1 Methodology and Criteria

The GEN-2015-088 generators and capacitors (if any) were switched out of service while other collector system elements remained in-service. A shunt reactor was tested at the phase's collection substation 34.5 kV bus to set the MVAr flow into the POI to approximately zero. The size of the shunt reactor is equivalent to the charging current value at unity voltage and the compensation provided is proportional to the voltage effects on the charging current (i.e. for voltages above unity, reactive compensation is greater than the size of the reactor).

4.2 Results

The results from the analysis showed that the GEN-2015-088 project needed an approximately 23.4 MVAr shunt reactor at the project substation, to reduce the POI MVAr to zero. This is an increase from the 22.2 MVAr found in the previous DISIS study[2]. Figure 4-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero. The final shunt reactor requirements for GEN-2015-088 is shown in Table 4-1.

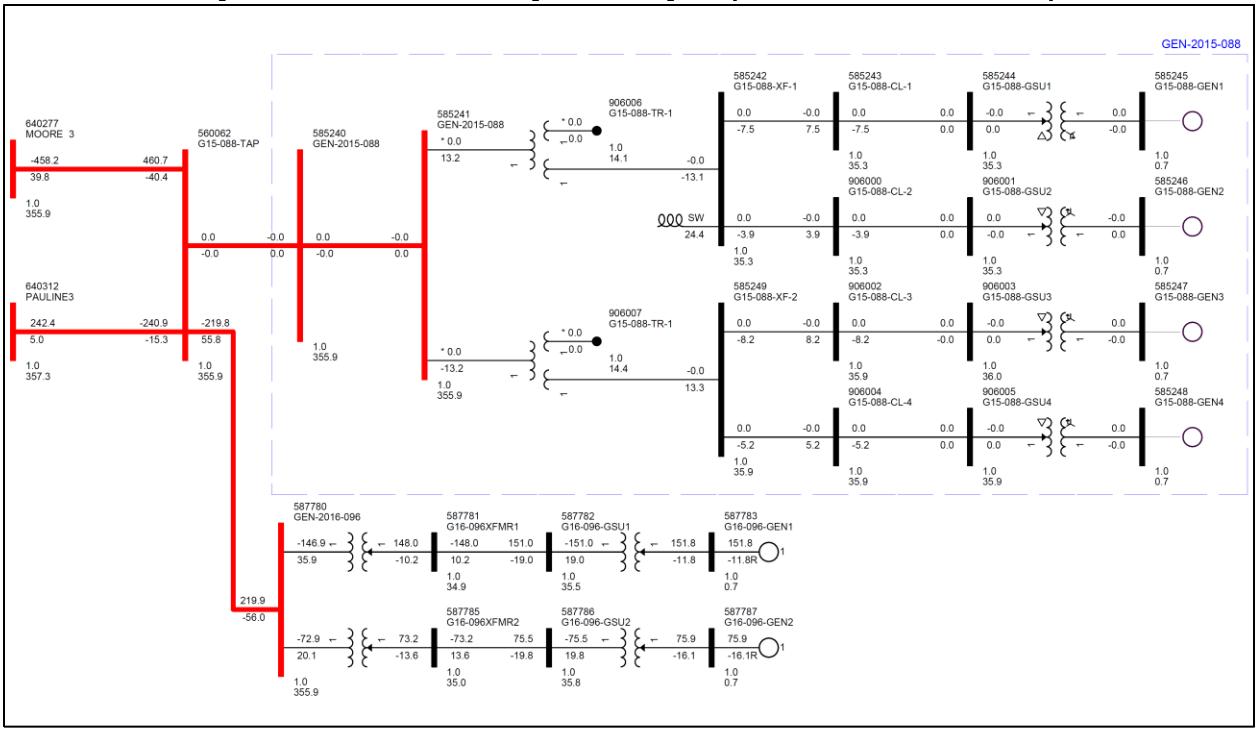
The information gathered from the charging current compensation analysis is provided as information to the customer and Transmission Owner. SPP does not require additional reactive requirements based on the results of this analysis.

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

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)		
			17WP	18SP	26SP
GEN-2015-088	560062	Tap on Moore (640277) to Pauline (640312) 345 kV (G15-088-TAP [aka Tobias 345 kV])	23.4	23.4	23.4

[2] Definitive Interconnection System Impact Study for Generation Interconnection Requests (DISIS-2015-002-1) – August 2016

Figure 4-1: GEN-2015-088 Single Line Diagram (Modification Shunt Reactor)



5.0 Short Circuit Analysis

A short circuit study was performed using the 2018SP and 2026SP models for GEN-2015-088. The detailed results of the short circuit analysis are provided in Appendix B.

5.1 Methodology

The short circuit analysis included applying a 3-phase fault on buses up to 5 levels away from the 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 GEN-2015-088 online.

5.2 Results

The results of the short circuit analysis for the 2018SP and 2026SP models are summarized in Table 5-1 through Table 5-3 respectively. The GEN-2015-088 POI bus fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 11.12 kA.

The maximum fault current calculated within 5 buses of the GEN-2015-088 POI was less than 43 kA for the 2018SP and 2026SP models respectively. The maximum GEN-2015-088 contribution to three-phase fault current was about 9.5% and 0.96 kA.

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
2018SP	10.08	11.04	0.96	9.5%
2026SP	10.16	11.12	0.96	9.5%

Table 5-2: 2018SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	16.5	0.01	0.3%
115	30.1	0.14	0.9%
161	42.0	0.03	0.1%
230	19.8	0.07	0.4%
345	31.4	0.96	9.5%
Max	**42.0**	**0.96**	**9.5%**

Table 5-3: 2026SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	16.9	0.01	0.3%
115	30.6	0.14	0.8%
161	42.2	0.03	0.1%
230	19.9	0.07	0.4%
345	31.8	0.96	9.5%
Max	**42.2**	**0.96**	**9.5%**

The results of the short circuit analysis for the 2018SP and 2026SP GGS models are summarized in Table 5-4 through Table 5-6 respectively. The GEN-2015-088 POI bus fault current magnitudes are provided in Table 5-4 showing a maximum fault current of 11.03 kA.

The maximum fault current calculated within 5 buses of the GEN-2015-088 POI was less than 43 kA for the 2018SP and 2026SP GGS models respectively. The maximum GEN-2015-088 contribution to three-phase fault current was about 9.4% and 0.94 kA.

Table 5-4: POI GGS Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
2018SP GGS	10.00	10.94	0.94	9.4%
2026SP GGS	10.09	11.03	0.94	9.4%

Table 5-5: 2018SP GGS Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	16.4	0.01	0.2%
115	30.0	0.13	0.8%
161	42.0	0.02	0.1%
230	19.4	0.07	0.4%
345	31.3	0.94	9.4%
Max	**42.0**	**0.94**	**9.4%**

Table 5-6: 2026SP GGS Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	16.9	0.01	0.2%
115	30.5	0.13	0.8%
161	42.2	0.02	0.1%
230	19.6	0.06	0.4%
345	31.8	0.94	9.4%
Max	**42.2**	**0.94**	**9.4%**

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the turbine configuration change and other modifications to the GEN-2015-088 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 A. The simulation plots can be found in Appendix D.

6.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested 36 x Siemens Gamesa 2.7-129 2.75 MW (SWTGU2) + 30 x Siemens Gamesa 145 4.5 MW (GMD041308) + 33 x Vestas V110 2.0 MW (VC19065401) configuration for the GEN-2015-088 generating facilities. This stability analysis was performed using PTI's PSS/E version 33.7 software.

The stability models were developed using the models from DISIS-2016-002-2 for Group 9. The modifications requested for the GEN-2015-088 project was used to create modified stability models for this impact study.

The modified dynamics model data the DISIS-2015-002 Group 9 request, GEN-2015-088, is provided in Appendix A. The modified power flow models and associated dynamics database were initialized (no-fault test) to confirm that there were no errors in the initial conditions of the system and the dynamic data.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2015-088 and other equally and prior queued projects in Group 9. In addition, voltages of five (5) buses away from the POI of GEN-2015-088 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within this study area including 534 (SUNC), 536 (WERE), 540 (GMO), 541 (KCPL), 635 (MEC), 640 (NPPD), 645 (OPPD), 650 (LES), and 652 (WAPA) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

6.2 Fault Definitions

Aneden simulated the faults previously simulated for GEN-2015-088 and selected additional fault events for GEN-2015-088 as required. The new set of faults were simulated using the modified study models. The fault events included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers. The simulated faults are listed and described in Table 6-1 below. These contingencies were applied to the modified 2017 Winter Peak, 2018 Summer Peak, and the 2026 Summer Peak models (including the GGS models).

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT26-3PH	P1	3 phase fault on the Grand Island (653571) to Sweetwater (640374) 345kV line circuit 1, near Grand Island. a. Apply fault at the Grand Island 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT27-3PH	P1	3 phase fault on the Grand Island (653571) to McCool (640271) 345kV line circuit 1, near Grand Island. a. Apply fault at the Grand Island 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT29-3PH	P1	3 phase fault on the Sweetwater (640374) to Axtell (640065) 345kV line circuit 1, near Sweetwater. a. Apply fault at the Sweetwater 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT30-3PH	P1	3 phase fault on the Sweetwater (640374) to Grand Island (653571) 345kV line circuit 1, near Sweetwater. a. Apply fault at the Sweetwater 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT32-3PH	P1	3 phase fault on the Axtell (640065) to Pauline (640312) 345kV line circuit 1, near Axtell. a. Apply fault at the Axtell 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT33-3PH	P1	3 phase fault on the Axtell 345/115/13.8kV (640065/640066/640067) Transformer, near Axtell. a. Apply fault at the Axtell 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT34-3PH	P1	3 phase fault on the Axtell (640065) to G16-050-Tap (560082) 345kV line circuit 1, near Axtell. a. Apply fault at the Axtell 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT35-3PH	P1	3 phase fault on the G16-050-Tap (560082) to Post Rock (530583) 345kV line circuit 1, near G16-050-Tap. a. Apply fault at the G16-050-Tap 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT44-3PH	P1	3 phase fault on the Pauline (640312) to G15-088-Tap (560062) 345kV line circuit 1, near Pauline. a. Apply fault at the Pauline 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT45-3PH	P1	3 phase fault on the Pauline (640312) to Axtell (640065) 345kV line circuit 1, near Pauline. a. Apply fault at the Pauline 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT46-3PH	P1	3 phase fault on the Pauline (640312/640313/640315) 345/115/13.8kV transformer, near Pauline. a. Apply fault at the Pauline 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT47-3PH	P1	3 phase fault on the Moore (640277) to Cooper (640139) 345kV line circuit 1, near Moore. a. Apply fault at the Moore 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT48-3PH	P1	3 phase fault on the Moore (640277) to Rokeby (650189) 345kV line circuit 1, near Moore. a. Apply fault at the Moore 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT49-3PH	P1	3 phase fault on the Moore (640277) to NW68HOLDRG3 (650114) 345kV line circuit 1, near Moore. a. Apply fault at the Moore 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT50-3PH	P1	3 phase fault on the Moore (640277) to G15-088-Tap (560062) 345kV line circuit 1, near Moore. a. Apply fault at the Moore 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT51-3PH	P1	3 phase fault on the Moore/Sheldon (640277/640278/640280) 345/115/13.8kV transformer, near Moore. a. Apply fault at the Moore 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT90-3PH	P1	3 phase fault on the G15-088-Tap (560062) to Moore (640277) 345kV line circuit 1, near G15-088-Tap. a. Apply fault at the G15-088-Tap 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT94-3PH	P1	3 phase fault on the G15-088-Tap (560062) to Pauline (640312) 345kV line circuit 1, near G15-088-Tap. a. Apply fault at the G15-088-Tap 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT67-SB	P4	**Sweetwater 345kV Stuck Breaker Scenario 3** a. Apply single phase fault at the Sweetwater (640374) 345kV bus. b. Wait 16 cycles and remove fault. c. Trip Sweetwater (640374) to Axtell (640065) 345kV line circuit 1. d. Trip Sweetwater (640374) to Grand Island (653571) 345kV line circuit 1.
FLT68-SB	P4	**Pauline 345kV Stuck Breaker Scenario 1** a. Apply single phase fault at the Pauline (640312) 345kV bus. b. Wait 16 cycles and remove fault. c. Trip Pauline 345/115/13.8kV (640312/640313/640315) transformer. d. Trip Pauline (640312) to Axtell (640065) 345kV line circuit 1.
FLT69-SB	P4	**Pauline 345kV Stuck Breaker Scenario 2** a. Apply single phase fault at the Pauline (640312) 345kV bus. b. Wait 16 cycles and remove fault. c. Trip Pauline 345/115/13.8kV (640312/640313/640315) transformer. d. Trip Pauline (640312) to G15-088-TAP (560062) 345kV line circuit 1.
FLT30-PO1	P6	**Prior Outage on the Sweetwater (640374) – Axtell (640065) 345kV line circuit 1** 3 phase fault on the Sweetwater (640374) to Grand Island (653571) 345kV line circuit 1, near Sweetwater. a. Apply fault at the Sweetwater 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT45-PO2	P6	**Prior Outage on the Pauline 345/115/13.8kV (640312/640313/640315) transformer** 3 phase fault on the Pauline (640312) to Axtell (640065) 345kV line circuit 1, near Pauline. a. Apply fault at the Pauline 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT44-PO2	P6	**Prior Outage on the Pauline 345/115/13.8kV (640312/640313/640315) transformer** 3 phase fault on the Pauline (640312) to G15-088-Tap (560062) 345kV line circuit 1, near Pauline. a. Apply fault at the Pauline 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT90-PO2	P6	**Prior Outage on the Pauline 345/115/13.8kV (640312/640313/640315) transformer** 3 phase fault on the G15-088-Tap (560062) to Moore (640277) 345kV line circuit 1, near G15-088-Tap. a. Apply fault at the G15-088-Tap 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT48-PO5	P6	**Prior Outage on the Moore (640277) - COOPER 3 (640139) 345kV kV line circuit 1** 3 phase fault on the Moore (640277) to 103&ROKEBY3 (650189) 345kV line circuit 1, near Moore. a. Apply fault at the Moore 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT49-PO5	P6	**Prior Outage on the Moore (640277) - COOPER 3 (640139) 345kV kV line circuit 1** 3 phase fault on the Moore (640277) to NW68HOLDRG3 (650114) 345kV line circuit 1, near Moore. a. Apply fault at the Moore 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT94-PO5	P6	**Prior Outage on the Moore (640277) - COOPER 3 (640139) 345kV kV line circuit 1** 3 phase fault on the G15-088-Tap (560062) to Pauline (640312) 345kV line circuit 1, near G15-088-Tap. a. Apply fault at the G15-088-Tap 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9001-3PH	P1	3 phase fault on the NW68HOLDRG3 (650114) to COLMB. E3 (640125) 345 kV line circuit 1, near NW68HOLDRG3. a. Apply fault at the NW68HOLDRG3 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line and remove fault.
FLT9002-3PH	P1	3 phase fault on the NW68HOLDRG (650114) 345 kV / (650214) 115 kV / (640314) 13.8 kV Transformer circuit 1, near NW68HOLDRG3 345 kV. a. Apply fault at the NW68HOLDRG3 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9003-3PH	P1	3 phase fault on the NW68HOLDRG3 (650114) to WAGENER (650185) 345 kV line circuit 1, near NW68HOLDRG3. a. Apply fault at the NW68HOLDRG3 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line and remove fault.
FLT9004-3PH	P1	3 phase fault on the 103&ROKEBY3 (650189) to WAGENER (650185) 345 kV line circuit 1, near 103&ROKEBY3. a. Apply fault at the 103&ROKEBY3 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line and remove fault.
FLT9005-3PH	P1	3 phase fault on the 103&ROKEBY3 (650189) to S3458 3 (645458) 345 kV line circuit 1, near 103&ROKEBY3. a. Apply fault at the 103&ROKEBY3 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line and remove fault.
FLT9006-3PH	P1	3 phase fault on the COOPER (640139) 345 kV / (640009) 22.0 kV transformer circuit 1, near COOPER 345 kV. a. Apply fault at the COOPER 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer. **Trip Generator COOPER1G (640009).**
FLT9007-3PH	P1	3 phase fault on the COOPER (640139) 345 kV / (640140) 161 kV / (640142) 13.8 kV transformer circuit 1, near COOPER 345 kV. a. Apply fault at the COOPER 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9008-3PH	P1	3 phase fault on the COOPER (640139) to ATCHSN 3 (635017) 345 kV line circuit 1, near COOPER. a. Apply fault at the COOPER 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line and remove fault.
FLT9009-3PH	P1	3 phase fault on the COOPER (640139) to ST JOE 3 (541199) 345 kV line circuit 1, near COOPER. a. Apply fault at the COOPER 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line and remove fault.
FLT9010-3PH	P1	3 phase fault on the COOPER (640139) to 7FAIRPT (300039) 345 kV line circuit 1, near COOPER. a. Apply fault at the COOPER 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9011-3PH	P1	3 phase fault on the MCCOOL 3 (640271) to GR ISLD3 (653571) 345 kV line circuit 1, near MCCOOL 3. a. Apply fault at the MCCOOL 3 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line and remove fault.
FLT9012-3PH	P1	3 phase fault on the MCCOOL (640271) 345 kV / (640272) 115 kV / (640274) 13.8 kV transformer circuit 1, near MCCOOL 345 kV. a. Apply fault at the MCCOOL 345 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9013-3PH	P1	3 phase fault on the Moore (640277) to MCCOOL 3 (640271) 345kV line circuit 1, near Moore. a. Apply fault at the Moore 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9014-3PH	P1	3 phase fault on the AXTELL 3 (640065) to SWEET W3 (640374) 345 kV line circuit 1, near AXTELL 3. a. Apply fault at the AXTELL 3 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line and remove fault.
FLT1001-SB	P4	**Moore 345 kV Stuck Breaker Scenario** a. Apply single phase fault at the Moore (640277) 345 kV bus. b. Wait 16 cycles and remove fault. c. Trip MOORE 3 (640277) to 103&ROKEBY3 (650189) 345 kV line circuit 1. d. Trip MOORE 3 (640277) to MCCOOL 3 (640271) 345 kV line circuit 1.
FLT1002-SB	P4	**Moore 345 kV Stuck Breaker Scenario** a. Apply single phase fault at the Moore (640277) 345 kV bus. b. Wait 16 cycles and remove fault. c. Trip MOORE 3 (640277) to NW68HOLDRG3 (650114) 345 kV line circuit 1. d. Trip MOORE 3 (640277) to G15-088-TAP (560062) 345 kV line circuit 1.
FLT1003-SB	P4	**Moore 345 kV Stuck Breaker Scenario** a. Apply single phase fault at the Moore (640277) 345 kV bus. b. Wait 16 cycles and remove fault. c. Trip MOORE 3 (640277) 345 kV /SHELDON7 (640278) 115 kV / MOORE 9 (640280) 13.8 kV transformer circuit 1. d. Trip MOORE 3 (640277) to G15-088-TAP (560062) 345 kV line circuit 1.
FLT1004-SB	P4	**Moore 345 kV Stuck Breaker Scenario** a. Apply single phase fault at the Moore (640277) 345 kV bus. b. Wait 16 cycles and remove fault. c. Trip MOORE 3 (640277) 345 kV /SHELDON7 (640278) 115 kV / MOORE 9 (640280) 13.8 kV transformer circuit 1. d. Trip MOORE 3 (640277) to COOPER 3 (640139) 345 kV line circuit 1.
FLT1005-SB	P4	**Moore 345 kV Stuck Breaker Scenario** a. Apply single phase fault at the Moore (640277) 345 kV bus. b. Wait 16 cycles and remove fault. c. Trip MOORE 3 (640277) to NW68HOLDRG3 (650114) 345 kV line circuit 1. d. Trip MOORE 3 (640277) to MCCOOL 3 (640271) 345 kV line circuit 1.
FLT1006-SB	P4	**Moore 345 kV Stuck Breaker Scenario** a. Apply single phase fault at the Moore (640277) 345 kV bus. b. Wait 16 cycles and remove fault. c. Trip MOORE 3 (640277) to 103&ROKEBY3 (650189) 345 kV line circuit 1. d. Trip MOORE 3 (640277) to COOPER 3 (640139) 345 kV line circuit 1.
FLT47-PO3	P6	**Prior Outage on the G15-088-TAP (560062) – PAULINE3 (640312) 345 kV line** 3 phase fault on the Moore (640277) to Cooper (640139) 345kV line circuit 1, near Moore. a. Apply fault at the Moore 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT48-PO3	P6	**Prior Outage on the G15-088-TAP (560062) – PAULINE3 (640312) 345 kV line** 3 phase fault on the Moore (640277) to Rokeby (650189) 345kV line circuit 1, near Moore. a. Apply fault at the Moore 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT49-PO3	P6	**Prior Outage on the G15-088-TAP (560062) – PAULINE3 (640312) 345 kV line** 3 phase fault on the Moore (640277) to NW68HOLDRG3 (650114) 345kV line circuit 1, near Moore. a. Apply fault at the Moore 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT51-PO3	P6	**Prior Outage on the G15-088-TAP (560062) – PAULINE3 (640312) 345 kV line** 3 phase fault on the Moore/Sheldon (640277/640278/640280) 345/115/13.8kV transformer, near Moore. a. Apply fault at the Moore 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9013-PO3	P6	**Prior Outage on the G15-088-TAP (560062) – PAULINE3 (640312) 345 kV line** 3 phase fault on the Moore (640277) to MCCOOL 3 (640271) 345kV line circuit 1, near Moore. a. Apply fault at the Moore 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT34-PO4	P6	**Prior Outage on the G15-088-TAP (560062) – MOORE 3 (640277) 345 kV line** 3 phase fault on the Axtell (640065) to G16-050-Tap (560082) 345kV line circuit 1, near Axtell. a. Apply fault at the Axtell 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT45-PO4	P6	**Prior Outage on the G15-088-TAP (560062) – MOORE 3 (640277) 345 kV line** 3 phase fault on the Pauline (640312) to Axtell (640065) 345kV line circuit 1, near Pauline. a. Apply fault at the Pauline 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT46-PO4	P6	**Prior Outage on the G15-088-TAP (560062) – MOORE 3 (640277) 345 kV line** 3 phase fault on the Pauline (640312/640313/640315) 345/115/13.8kV transformer, near Pauline. a. Apply fault at the Pauline 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9014-PO4	P6	**Prior Outage on the G15-088-TAP (560062) – MOORE 3 (640277) 345 kV line** 3 phase fault on the AXTELL 3 (640065) to SWEET W3 (640374) 345 kV line circuit 1, near AXTELL 3. a. Apply fault at the AXTELL 3 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line and remove fault.

6.3 Results

Table 6-2 shows the results of the fault events simulated for each of the three modified cases. The associated stability plots are provided in Appendix D.

Table 6-2: GEN-2015-088 Dynamic Stability Results

Fault ID	17WP & 17WP_GGS			18SP & 18SP_GGS			26SP & 26SP_GGS		
	Volt. Recovery	Volt. Violation	Stable	Volt. Recovery	Volt. Violation	Stable	Volt. Recovery	Volt. Violation	Stable
FLT26-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT27-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT29-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT30-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT32-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
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
FLT44-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT45-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT46-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT47-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT48-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	17WP & 17WP_GGS			18SP & 18SP_GGS			26SP & 26SP_GGS		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable
FLT49-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT50-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT51-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT90-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT94-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT67-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT68-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT69-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
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
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
FLT30-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT45-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT44-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT90-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT47-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT48-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT49-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT51-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT34-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT45-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT46-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT48-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT49-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT94-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

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

7.0 Material Modification Determination

In accordance with Attachment V of SPP's Open Access Transmission Tariff, for modifications other than those specifically permitted by Attachment V, SPP shall evaluate the proposed modifications prior to making them and inform the Interconnection Customer in writing of whether the modifications would constitute a Material Modification. A Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later Queue priority date.

7.1 Results

SPP determined the requested modification is not a Material Modification based on the results of this Modification Request Impact Study performed by Aneden. Aneden evaluated the impact of the requested modification on the prior study results. Aneden determined that the requested modification resulted in similar dynamic stability and short circuit analyses and that the prior study power flow results are not negatively impacted.

This determination implies that any network upgrades already required by GEN-2015-088 would not be negatively impacted and that no new upgrades are required due to the requested modification, thus not resulting in a material impact on the cost or timing of any Interconnection Request with a later Queue priority date.

8.0 Conclusions

The Interconnection Customer for GEN-2015-088 requested a Modification Request Impact Study to assess the impact of the turbine and facility changes to a configuration with a total of 36 x Siemens Gamesa 2.7-129 2.75 MW + 30 x Siemens Gamesa 145 4.5 MW + 33 x Vestas V110 2.0 MW wind turbines for total capacity of 300 MW. In addition, the modification request included changes to the collection system, generator substation transformer, main substation transformer, and generation interconnection line.

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.83%. However, SPP determined that the turbine change from Vestas to a combination of Vestas and Siemens Gamesa turbines required short circuit and dynamic stability analyses.

The scope of this modification request study included a charging current compensation analysis, short circuit analysis, and dynamic stability analysis.

The results of the charging current compensation analysis performed using the 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak models showed that the GEN-2015-088 project needed 23.4 MVAr of reactor shunts on the 34.5 kV bus of the project substation, an increase from the 22.2 MVAr found in the previous DISIS study[3]. 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 or no-wind conditions. The information gathered from the charging current compensation analysis is provided as information to the customer and Transmission Owner. SPP does not require additional reactive requirements based on the results of this analysis.

The results from the short circuit analysis with the updated topology showed that the maximum GEN-2015-088 contribution to three-phase fault currents in the immediate systems at or near GEN-2015-088 was not greater than 0.96 kA for the 2018SP and 2026SP models and 0.94 for the 2018SP and 2026SP GGS models. All three-phase fault current levels within 5 buses of the POI with the GEN-2015-088 generators online were below 43 kA for the 2018SP and 2026SP models, as well as the 2018SP and 2026SP GGS models.

The dynamic stability analysis was performed using the six DISIS-2016-002-2 models 2017 Winter Peak, 2018 Summer Peak, 2026 Summer Peak, 2017 Winter Peak GGS, 2018 Summer Peak GGS, and 2026 Summer Peak GGS. Up to 58 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

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

[3] Definitive Interconnection System Impact Study for Generation Interconnection Requests (DISIS-2015-002-1) – August 2016

The requested modification has been determined by SPP to not be a Material Modification. The requested modification does not have a material impact on the cost or timing of any Interconnection Request with a later Queue priority date.

It is likely that the customer may be required to reduce its generation output to 0 MW in real-time, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Nothing in this study should be construed as a guarantee of transmission service or delivery rights. If the customer wishes to obtain deliverability to final customers, a separate request for transmission service must be requested on Southwest Power Pool's OASIS by the customer.