Report on

GEN-2016-003
Modification Request Impact Study

Revision R1 **May 31, 2022**

Submitted to
Southwest Power Pool

anedenconsulting.com

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPENDICES

Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
05/31/2022	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-2016-003, an active Generation Interconnection Requests (GIR) with a point of interconnection (POI) at the G16-003-TAP 345 kV bus on the Badger to Woodward 345 kV line.

The GEN-2016-003 project interconnects in the Oklahoma Gas & Electric (OKGE) control area with a total project size of 251.4 MW controlled to the allowed amount of 248.4 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2016-003 to change the turbine configuration to 59 x Vestas 4.2 MW + 1 x Vestas 2.2 MW for a total capacity of 250 MW. This generating capacity for GEN-2016-003 (250 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 248.4 MW, as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI to 248.4 MW.

In addition, the modification request included changes to the collection system, generator step-up transformers, generation interconnection line rating, main substation transformers, and reactive power devices. The existing and modified configurations for GEN-2016-003 are shown in Table ES-2.

Table ES-1: GEN-2016-003 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2016-003	Tap on Badger (515677) to Woodward (515375) 345 kV Line (G16-003-TAP 560071)	59 x Vestas 4.2 MW + 1 x Vestas 3.6 MW	251.4 (PPC to limit to 248.4)

Table ES-2: GEN-2016-003 Modification Request

<table>
<tr><th>Facility</th><th colspan="2">Existing Configuration</th><th colspan="2">Modification Configuration</th></tr>
<tr><td>Point of Interconnection</td><td colspan="2">Tap on Badger (515677) to Woodward (515375) 345 kV (G16-003-TAP 560071)</td><td colspan="2">Tap on Badger (515677) to Woodward (515375) 345 kV (G16-003-TAP 560071)</td></tr>
<tr><td>Configuration/Capacity</td><td colspan="2">59 x Vestas 4.2 MW + 1 x Vestas 3.6 MW = 251.4 MW
PPC to limit POI injection to 248.4 MW</td><td colspan="2">59 x Vestas 4.2 MW + 1 x Vestas 2.2 MW = 250 MW
PPC to limit POI injection to 248.4 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td colspan="2">Length = 0.1 miles
R = 0.000128 pu
X = 0.005488 pu
B = 0.007800 pu
Rating MVA = 0 MVA</td><td colspan="2">Length = 0.1 miles
R = 0.000128 pu
X = 0.005488 pu
B = 0.007800 pu
Rating MVA = 809 MVA</td></tr>
<tr><td>Main Substation Transformer[1]</td><td colspan="2">X = 8.497%, R = 0.243%,
Winding MVA = 168 MVA,
Rating MVA = 280 MVA</td><td colspan="2">X = 10.819%, R = 0.156%,
Winding MVA = 168 MVA,
Rating MVA = 280 MVA</td></tr>
<tr><td>Equivalent GSU Transformer[1]</td><td>Gen 1 Equivalent Qty: 59
X = 5.706%, R = 0.713%,
Winding MVA = 303.85 MVA,
Rating MVA[2] = 303.9 MVA</td><td>Gen 2 Equivalent Qty: 1
X = 5.706%, R = 0.713%,
Winding MVA = 4.0 MVA,
Rating MVA = 4.0 MVA</td><td>Gen 1 Equivalent Qty: 59
X = 9.868%, R = 0.796%,
Winding MVA = 303.85 MVA,
Rating MVA[2] = 303.9 MVA</td><td>Gen 2 Equivalent Qty: 1
X = 8.973%, R = 0.696%,
Winding MVA = 4 MVA,
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<tr><td>Equivalent Collector Line[3]</td><td colspan="2">R = 0.004887 pu
X = 0.005296 pu
B = 0.068256 pu</td><td colspan="2">R = 0.003094 pu
X = 0.004705 pu
B = 0.112086 pu</td></tr>
<tr><td>Reactive Power Devices</td><td colspan="2">1 x 40 MVAR 34.5 kV Capacitor Bank</td><td colspan="2">2 X 13.5 MVAR 34.5 kV Capacitor Bank</td></tr>
<tr><td>Generator Dynamic Model[4] & Power Factor</td><td>59 x Vestas 4.2 MW (CP20065718)[4] +0.903/-0.942</td><td>1 x Vestas 3.6 MW (CP20065718)[4] +0.903/-0.942</td><td>59 x Vestas 4.2 MW (CP200653400)[4] +0.903/-0.942</td><td>1 x Vestas 2.2 MW (VC200453400)[4] +1.000/-0.975</td></tr>
</table>

1) X/R based on Winding MVA, 2) Rating rounded in PSS/E, 3) All pu are on 100 MVA Base 4) DYR stability model name

SPP determined that power flow analysis should not be performed based on the POI MW injection increase of 0.58% compared to the DISIS-2017-001 power flow models. However, SPP determined that while the modification used the same turbine manufacturer, Vestas, the change in stability model from CP20065718 to a combination of CP200653400 and VC200453400 required short circuit and dynamic stability analysis.

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

Aneden performed the analyses using the modification request data based on the DISIS 2017-001 stability study models:

1. 2019 Winter Peak (2019WP),
2. 2021 Light Load (2021LL),
3. 2021 Summer Peak (2021SP),
4. 2028 Summer Peak (2028SP)

All analyses were performed using the PTI PSS/E version 33 software and the results are summarized below.

The results of the charging current compensation analysis performed using the 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak models showed that the GEN-2016-003 project needed 11.95 MVAr of reactor shunts on the 34.5 kV bus of the project substation with the modifications in place, an increase from the 7.6 MVAr found in the previous modification 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 Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

The results from the short circuit analysis with the updated configuration showed that the maximum GEN-2016-003 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2016-003 POI was no greater than 0.37 kA for the 2021SP and 2028SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-003 generators online were below 46 kA for the 2021SP and 2028SP models.

The dynamic stability analysis was performed using PTI PSS/E version 33.10 software for the four modified study models, 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak. Up to 81 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults.

There were no damping or voltage recovery violations attributed to the GEN-2016-003 project 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 adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date. As the requested modification places the generating capacity of the Interconnection Request at a higher amount than its Interconnection Service, the customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

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] GEN-2016-003 Modification Request Impact Study – March 10, 2021

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-2016-003. 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 software. The results of each analysis are presented in the following sections.

1.1 Power Flow Analysis

To determine whether power flow analysis is required, SPP evaluates the difference in the real power output at the POI between the DISIS-2017-001 power flow configuration and the requested modification. Power flow analysis is performed if the difference in the real power may result in a significant impact on the results of the DISIS power flow analysis.

1.2 Dynamic 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 may result in 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 project'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-2016-003 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a point of interconnection (POI) at the G16-003-TAP 345 kV bus on the Badger to Woodward 345 kV line. At the time of the posting of this report, GEN-2016-003 is an active Interconnection Request with queue status of “IA FULLY EXECUTED/ON SCHEDULE.” GEN-2016-003 is a wind farm and has a maximum summer and winter queue capacity of 248.4 MW with Energy Resource Interconnection Service (ERIS).

The GEN-2016-003 project is currently in the DISIS-2016-001 cluster. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2016-003 configuration.

The GEN-2016-003 project interconnects in the Oklahoma Gas & Electric (OKGE) control area with a total project size of 251.4 MW controlled to the allowed amount of 248.4 MW as shown in Table 2-1 below.

Table 2-1: GEN-2016-003 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
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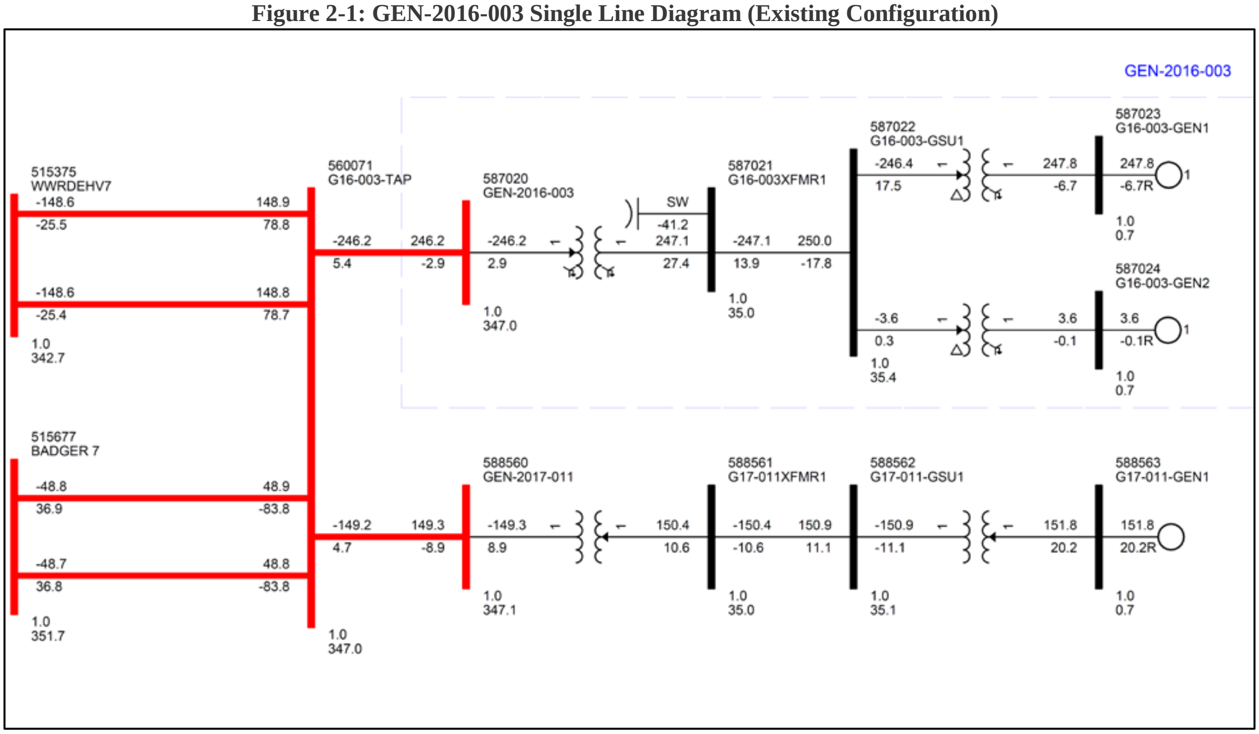
Figure 2-1: GEN-2016-003 Single Line Diagram (Existing Configuration)



This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2016-003 to a turbine configuration of 59 x Vestas 4.2 MW + 1 x Vestas 2.2 MW for a total capacity of 250 MW. This combined generating capacity for GEN-2016-003 (250 MW) exceeds the total Generator Interconnection Agreement (GIA) Interconnection Service amount, 248.4 MW, as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA. In addition, the modification request included changes to the collection system, generator step-up transformers, generation interconnection line rating, main substation transformers, and reactive power devices. Figure 2-2 shows the power flow model single line diagram for the GEN-2016-003 modification. The existing and modified configurations for GEN-2016-003 are shown in Table 2-2.

Figure 2-2: GEN-2016-003 Single Line Diagram (Modification Configuration)

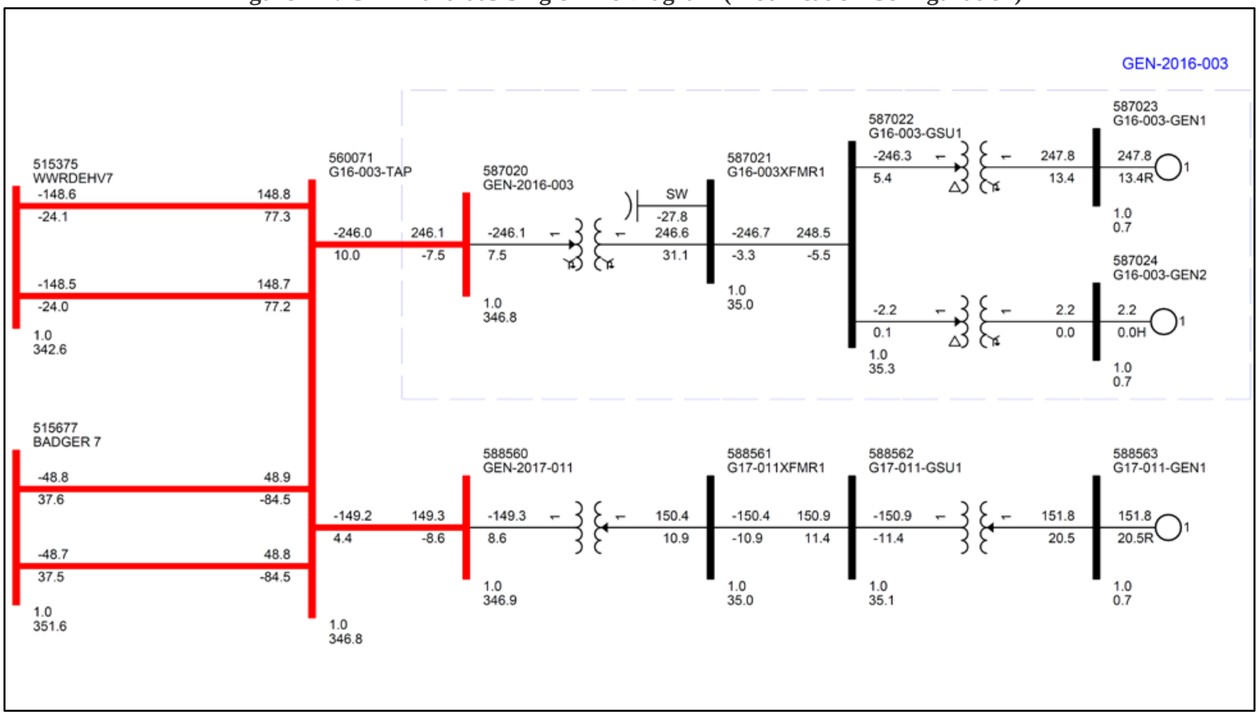


Table 2-2: GEN-2016-003 Modification Request

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3.0 Existing vs Modification Comparison

To determine which analyses are required for the Study, 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-2017-001 study models.

The methodology and results of the comparisons are described below. The analysis was completed using PSS/E version 33 software.

3.1 POI Injection Comparison

The real power injection at the POI was determined using PSS/E to compare the DISIS-2017-001 power flow configuration and the requested modification for GEN-2016-003. The percentage change in the POI injection was then evaluated. If the real power (MW) difference was determined to be significant (greater than 10%) 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 0.58%, in the real power output at the POI between the studied DISIS-2017-001 power flow configuration and requested modification shown in Table 3-1.

Table 3-1: GEN-2016-003 POI Injection Comparison

Interconnection Request	Existing POI Injection (MW)	Modification POI Injection (MW)	POI Injection Difference %
GEN-2016-003	244.6	246.0	0.58%

3.2 Turbine Parameters Comparison

SPP determined that while the modification used the same turbine manufacturer, Vestas, the change in stability model from CP20065718 to a combination of CP200653400 and VC200453400 required short circuit and dynamic stability analysis. This is because the short circuit contribution and 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.

As short circuit and dynamic stability analyses were required, a turbine parameters comparison was not needed for the determination of the scope of the study.

3.3 Equivalent Impedance Comparison Calculation

As the turbine stability model change 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-2016-003 to determine the capacitive charging effects under 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-2016-003 generators were switched out of service while other collection system elements remained in-service. A shunt reactor was tested at the project's collection substation 34.5 kV bus to offset 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-2016-003 project needed approximately 11.95 MVAr of compensation at its collector substation, to reduce the POI MVAr to zero. This is an increase from the 7.6 MVAr found in the previous modification study[2]. The final shunt reactor requirements for GEN-2016-003 are shown in Table 4-1. Figure 4-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the updated configuration.

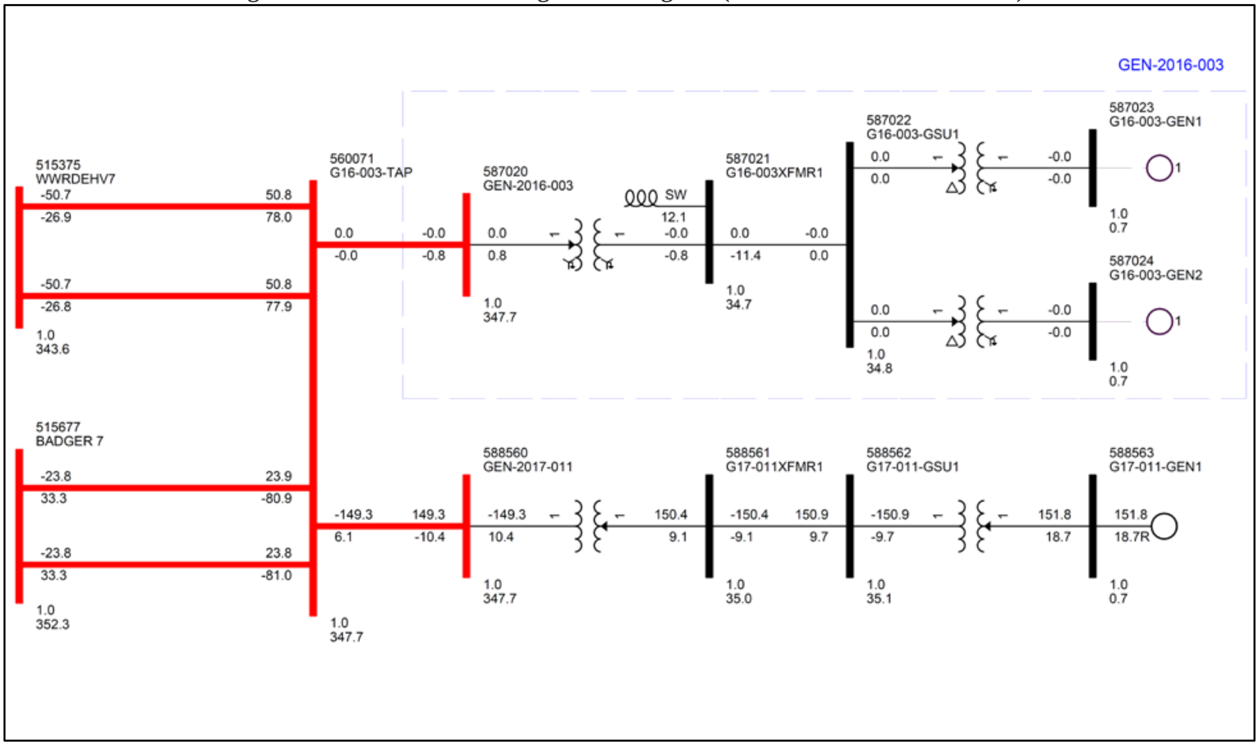
The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

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

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)			
			19WP	21LL	21SP	28SP
GEN-2016-003	560071	G16-003-TAP 345 kV	11.95	11.95	11.95	11.95

[2] GEN-2016-003 Modification Request Impact Study – March 10, 2021

Figure 4-1: GEN-2016-003 Single Line Diagram (Modification Shunt Reactor)



5.0 Short Circuit Analysis

A short circuit study was performed using the 2021SP and 2028SP model for GEN-2016-003. 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 in the transmission system with and without GEN-2016-003 online.

5.2 Results

The results of the short circuit analysis for the 2021SP and 2028SP models are summarized in Table 5-1 through Table 5-3 respectively. The GEN-2016-003 POI bus (G16-003-TAP 345 kV - 560071) fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 15.24 kA with the GEN-2016-003 project online.

The maximum fault current calculated within 5 buses of the GEN-2016-003 POI was less than 46 kA for the 2021SP and 2028SP models respectively. The maximum GEN-2016-003 contribution to three-phase fault current was about 2.5% and 0.37 kA.

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
2021SP	14.80	15.17	0.37	2.5%
2028SP	14.87	15.24	0.37	2.5%

Table 5-2: 2021SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	11.3	0.00	0.0%
115	19.8	0.00	0.0%
138	45.0	0.08	0.3%
230	27.3	0.01	0.1%
345	34.5	0.37	2.5%
Max	**45.0**	**0.37**	**2.5%**

Table 5-3: 2028SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	11.8	0.01	0.1%
115	19.7	0.00	0.0%
138	44.9	0.10	0.4%
230	25.7	0.01	0.0%
345	34.5	0.37	2.5%
Max	**44.9**	**0.37**	**2.5%**

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-2016-003 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 GEN-2016-003 configuration of 59 x Vestas 4.2 MW (CP200653400) + 1 x Vestas 2.2 MW (VC200453400). This stability analysis was performed using PTI's PSS/E version 33.10 software.

The stability models were developed using the DISIS-2017-001 models. The modifications requested for the GEN-2016-003 project were used to create modified stability models for this impact study.

The following system adjustments were made to address existing base case issues that are not attributed to the modification request:

1. The GEN-2017-018 frequency relay model 58863706 was disabled for bus 588637
2. The Frisco Wind G59REL protection model was disabled for bus 523160
3. The Oklaunion capacitor bank was switched online to 90MVAR in the 21LL case
4. The GEN-2016-118 generator at bus 587943 was set to a power factor of 0.98 in the 28SP prior outage case
5. GEN-2015-048 was updated with the latest project configuration

The modified dynamic model data for the GEN-2016-003 project 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-2016-003 and other equally and prior queued projects in the cluster group[3]. In addition, voltages of five (5) buses away from the POI of GEN-2016-003 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) 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-2016-003 and developed additional fault events 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 stuck breaker faults. The simulated faults are listed and described in Table 6-1 below. These contingencies were applied to the modified 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and the 2028 Summer Peak models.

[3] Based on the DISIS-2017-001 Cluster Groups

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT01-3PH	P1	3 phase fault on the G16-003-TAP (560071) to BADGER 7 (515677) 345kV line CKT 1, near G16-003-TAP. a. Apply fault at the G16-003-TAP 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT02-3PH	P1	3 phase fault on the G16-003-TAP (560071) to WWRDEHV7 (515375) 345kV line CKT 1, near G16-003-TAP. a. Apply fault at the G16-003-TAP 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT03-3PH	P1	3 phase fault on the WWRDEHV7 (515375) to DGRASSE7 (515852) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT04-3PH	P1	3 phase fault on DGRASSE 345kV (515852)/138kV (515853)/13.8kV (515854) transformer CKT 1, near DGRASSE7 345kV. a. Apply fault at the DGRASSE7 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT05-3PH	P1	3 phase fault on the TUCO_INT 7 (525832) to BORDER 7 (515458) 345kV line CKT 1, near TUCO_INT 7. a. Apply fault at the TUCO_INT 7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT06-3PH	P1	3 phase fault on the WWRDEHV7 (515375) to TATONGA7 (515407) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT07-3PH	P1	3 phase fault on WWDEHV-T2 345kV (515375)/138kV (515376)/13.8kV (515799) transformer CKT 2, near WWDEHV7 345kV. a. Apply fault at the WWDEHV7 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT08-3PH	P1	3 phase fault on the DGRASSE7 (515852) to THISTLE7 (539801) 345kV line CKT 1, near DGRASSE7. a. Apply fault at the DGRASSE7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT09-3PH	P1	3 phase fault on TUCO 345kV (525832)/230kV (525830)/13.2kV (525824) transformer CKT 1, near TUCO_INT 7 345kV. a. Apply fault at the TUCO_INT 7 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT10-3PH	P1	3 phase fault on the TUCO_INT 7 (525832) to O.K.U.-7 (511456) 345kV line CKT 1, near TUCO_INT 7. a. Apply fault at the TUCO_INT 7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT12-3PH	P1	3 phase fault on the THISTLE7 (539801) to BUFFALO7 (532782) 345kV line CKT 1, near THISTLE7. a. Apply fault at the THISTLE7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT13-3PH	P1	3 phase fault on the THISTLE7 (539801) to CLARKCOUNTY7 (539800) 345kV line CKT 1, near THISTLE7. a. Apply fault at the THISTLE7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT14-3PH	P1	3 phase fault on THISTLE T1 345kV (539801)/138kV (539804)/13.8kV (539802) transformer CKT 1, near THISTLE7 345kV. a. Apply fault at the THISTLE7 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT15-3PH	P1	3 phase fault on the BVRCNTY7 (515554) to BADGER 7 (515677) 345kV line CKT 1, near BVRCNTY7. a. Apply fault at the BVRCNTY7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT16-3PH	P1	3 phase fault on the BVRCNTY7 (515554) to HITCHLAND 7 (523097) 345kV line CKT 1, near BVRCNTY7. a. Apply fault at the BVRCNTY7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT23-3PH	P1	3 phase fault on the TATONGA7 (515407) to MATHWSN7 (515497) 345kV line CKT 1, near TATONGA7. a. Apply fault at the TATONGA7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT44-3PH	P1	3 phase fault on the WWRDEHV7 (515375) to BORDER 7 (515458) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT45-3PH	P1	3 phase fault on the TRAVERSE1 (900001) to MATHWSN7 (515497) 345kV line CKT 1, near TRAVERSE1. a. Apply fault at the TRAVERSE1 345kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generators G16-045-GEN3(587300), G16-045-GEN1(587303), G16-045-GEN2(587307), G16-057-GEN3(587380), G16-057-GEN1(587383), G16-057-GEN2(587387).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT46-3PH	P1	3 phase fault on the MATHWSN7 (515497) to REDNGTN7 (515875) 345kV line CKT 1, near MATHWSN7. a. Apply fault at the MATHWSN7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT47-3PH	P1	3 phase fault on the NORTWST7 (514880) to MATHWSN7 (515497) 345kV line CKT 1, near NORTWST7. a. Apply fault at the NORTWST7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT06-SB	P4	**Stuck Breaker on WWRDEHV7 (515375) 345kV bus.** a. Apply single-phase fault at WWRDEHV7 (515375) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the WWRDEHV7 to TATONGA (515407) 345kV line CKT 2. d. Trip the WWDEHV-T2 345kV (515375)/138kV (515376)/13.8kV (515795) transformer CKT 1.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT07-SB	P4	**Stuck Breaker on WWRDEHV7 (515375) 345kV bus.** a. Apply single-phase fault at WWRDEHV7 (515375) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the WWRDEHV7 to TATONGA (515407) 345kV line CKT 1. d. Trip the WWDEHV-T2 345kV (515375)/138kV (515376)/13.8kV (515799) transformer CKT 2.
FLT32-SB	P4	**Stuck Breaker on WWRDEHV7 (515375) 345kV bus.** a. Apply single-phase fault at WWRDEHV7 (515375) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the WWRDEHV7 (515375) to G16-003-Tap (560071)345 kV line CKT 2. d. Trip the WWRDEHV7 (515375) to G07621119-20 (515599) 345 kV line CKT 1. **Trip generators PC1_WTG2(585436), PC1_WTG1(585433), PC2_WTG2(585446), PC2_WTG1(585443), GW_WTG22(585418), GW_WTG21(585417), GW_WTG12(585414), GW_WTG11(585413), CB_WTG2(585426), CB_WTG1(585423).**
FLT14-SB	P4	**Stuck Breaker on BADGER (515677) 345kV bus.** a. Apply single-phase fault at BADGER (515677) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the BADGER (515677) to BVRCNTY7 (515554) 345 kV line CKT 1. d. Trip the BADGER (515677) to G16-003-TAP (560071) 345 kV line CKT 2.
FLT15-SB	P4	**Stuck Breaker on BADGER (515677) 345kV bus.** a. Apply single-phase fault at BADGER (515677) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the BADGER (515677) to G16-003-TAP (560071) 345 kV line CKT 1. d. Trip the BADGER (515677) to GEN-2015-082 (585190) line CKT 1. **Trip generator G15-082-GEN1 (585193).**
FLT17-SB	P4	**Stuck Breaker on BADGER (515677) 345kV bus.** a. Apply single-phase fault at BADGER (515677) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the BADGER (515677) to BVRCNTY7 (515554) 345 kV line CKT 2. d. Trip the BADGER (515677) to GEN-2015-082 (585190) line CKT 1. **Trip generator G15-082-GEN1 (585193).**
FLT19-SB	P4	**Stuck Breaker on BADGER (515677) 345kV bus.** a. Apply single-phase fault at BADGER (515677) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the BADGER (515677) to BVRCNTY7 (515554) 345 kV line CKT 2. d. Trip the BADGER (515677) to BVRCNTY7 (515554) 345 kV line CKT 1.
FLT02-PO1	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to G16-003-TAP (560071) 345kV line CKT 2;** 3 phase fault on the G16-003-TAP (560071) to WWRDEHV7 (515375) 345kV line CKT 1, near G16-003-TAP. a. Apply fault at the G16-003-TAP 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT03-PO2	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to TATONGA7 (515407) 345kV line CKT 2;** 3 phase fault on the WWRDEHV7 (515375) to DGRASSE7 (515852) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT06-PO2	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to TATONGA7 (515407) 345kV line CKT 2;** 3 phase fault on the WWRDEHV7 (515375) to TATONGA7 (515407) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT44-PO2	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to TATONGA7 (515407) 345kV line CKT 2;** 3 phase fault on the WWRDEHV7 (515375) to BORDER 7 (515458) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT03-PO3	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to DGRASSE7 (515852) 345kV line CKT 2;** 3 phase fault on the WWRDEHV7 (515375) to DGRASSE7 (515852) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT44-PO3	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to DGRASSE7 (515852) 345kV line CKT 2;** 3 phase fault on the WWRDEHV7 (515375) to BORDER 7 (515458) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT9001-3PH	P1	3 phase fault on the G16-003-TAP (560071) to GEN-2017-001 (588560) 345kV line CKT 1, near G16-003-TAP. a. Apply fault at the G16-003-TAP 345kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G17-011-GEN1 (588563)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	P1	3 phase fault on the BADGER 7 (515677) to GEN-2015-082 (585190) 345kV line CKT 1, near BADGER 7. a. Apply fault at the BADGER 7 345kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G15-082-GEN1 (585193)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9003-3PH	P1	3 phase fault on the BADGER 7 (515677) to GEN-2011-014 (515686) 345kV line CKT 1, near BADGER 7. a. Apply fault at the BADGER 7 345kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G11-014-GEN1 (515678)** **Trip generator G11-014-GEN2 (515682)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9004-3PH	P1	3 phase fault on the BADGER 7 (515677) to BVRCNTY7 (515554) 345kV line CKT 1, near BADGER 7. a. Apply fault at the BADGER 7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1	3 phase fault on the BVRCNTY7 (515554) to PALDR2W7 (515590) 345kV line CKT 1, near BVRCNTY7. a. Apply fault at the BVRCNTY7 345kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G08-047-GEN2 (573510).** **Trip generator G08-047-GEN1 (515905).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9006-3PH	P1	3 phase fault on the BVRCNTY7 (515554) to BALKOW 7 (515618) 345kV line CKT 1, near BVRCNTY7. a. Apply fault at the BVRCNTY7 345kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator BALKOWG1 (515658).** **Trip generator BALKOWG1 (515659).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9007-3PH	P1	3 phase fault on the TATONGA7 (515407) to MAMTHPW7 (515585) 345kV line CKT 1, near TATONGA7. a. Apply fault at the TATONGA7 345kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator MMTHPWG1 (515903)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	P1	3 phase fault on the TATONGA7 (515407) to SLNGWND7 (515582) 345kV line CKT 1, near TATONGA7. a. Apply fault at the TATONGA7 345kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator SILNGWG1 (515587)** **Trip generator SILNGWG2 (515898)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9009-3PH	P1	3 phase fault on the TATONGA7 (515407) to CRSRDSW7 (515448) 345kV line CKT 1, near TATONGA7. a. Apply fault at the TATONGA7 345kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator CRSRD-WTG2 (515910)** **Trip generator CRSRD-WTG1 (515911)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9010-3PH	P1	3 phase fault on the MATHWSN7 (515497) to TRAVERSE1 (900001) 345kV line CKT 1, near MATHWSN7. a. Apply fault at the MATHWSN7 345kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generators G16-045-GEN3(587300), G16-045-GEN1(587303), G16-045-GEN2(587307), G16-057-GEN3(587380), G16-057-GEN1(587383), G16-057-GEN2(587387).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9011-3PH	P1	3 phase fault on the MATHWSN7 (515497) to CIMARON7 (514901) 345kV line CKT 1, near MATHWSN7. a. Apply fault at the MATHWSN7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT9012-3PH	P1	3 phase fault on the MATHWSN7 (515497) to NORTWST7 (514880) 345kV line CKT 1, near MATHWSN7. a. Apply fault at the MATHWSN7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT9013-3PH	P1	3 phase fault on the BORDER 7 (515458) to TUCO_INT 7 (525832) 345kV line CKT 1, near BORDER 7. a. Apply fault at the BORDER 7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9014-3PH	P1	3 phase fault on the TUCO_INT 7 (525832) to ELK_CT1 (525850) 345kV line CKT 1, near TUCO_INT 7. a. Apply fault at the TUCO_INT 7 345kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator ELK_2 (525845)** **Trip generator ELK_1 (525844)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9015-3PH	P1	3 phase fault on the THISTLE7 (539801) to GEN-2017-018 (588630) 345kV line CKT 1, near THISTLE7. a. Apply fault at the THISTLE7 345kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G17-018-GEN2 (588637)** **Trip generator G17-018-GEN1 (588633)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9016-3PH	P1	3 phase fault on the WWRDEHV7 (515375) to G16-003-TAP (560071) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT9017-3PH	P1	3 phase fault on the WWRDEHV4 (515376) to OUSPRT 4 (515398) 138kV line CKT 1, near WWRDEHV4. a. Apply fault at the WWRDEHV4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. **Trip generator OUSPRTG1 (515399)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9018-3PH	P1	3 phase fault on the WWRDEHV4 (515376) to KEENAN 4 (515394) 138kV line CKT 1, near WWRDEHV4. a. Apply fault at the WWRDEHV4 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line. **Trip generator KEENANG1 (515395)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9019-3PH	P1	3 phase fault on the WWRDEHV4 (515376) to WWDPST 4 (515425) 138kV line CKT 1, near WWRDEHV4. a. Apply fault at the WWRDEHV4 138kV bus. b. Clear fault after 7 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 7 cycles, then trip the line in (b) and remove fault.
FLT9020-3PH	P1	3 phase fault on the WWRDEHV4 (515376) to IODINE-4 (514796) 138kV line CKT 1, near WWRDEHV4. a. Apply fault at the WWRDEHV4 138kV bus. b. Clear fault after 7 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 7 cycles, then trip the line in (b) and remove fault.
FLT01-PO1	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to G16-003-TAP (560071) 345kV line CKT 2;** 3 phase fault on the G16-003-TAP (560071) to BADGER 7 (515677) 345kV line CKT 1, near G16-003-TAP. a. Apply fault at the G16-003-TAP 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT03-PO1	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to G16-003-TAP (560071) 345kV line CKT 2;** 3 phase fault on the WWRDEHV7 (515375) to DGRASSE7 (515852) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT06-PO1	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to G16-003-TAP (560071) 345kV line CKT 2;** 3 phase fault on the WWRDEHV7 (515375) to TATONGA7 (515407) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT07-PO1	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to G16-003-TAP (560071) 345kV line CKT 2;** 3 phase fault on WWDEHV-T2 345kV (515375)/138kV (515376)/13.8kV (515799) transformer CKT 2, near WWDEHV7 345kV. a. Apply fault at the WWDEHV7 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT44-PO1	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to G16-003-TAP (560071) 345kV line CKT 2;** 3 phase fault on the WWRDEHV7 (515375) to BORDER 7 (515458) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT9013-PO1	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to G16-003-TAP (560071) 345kV line CKT 2;** 3 phase fault on the BORDER 7 (515458) to TUCO_INT 7 (525832) 345kV line CKT 1, near BORDER 7. a. Apply fault at the BORDER 7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT9016-PO1	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to G16-003-TAP (560071) 345kV line CKT 2;** 3 phase fault on the WWRDEHV7 (515375) to G16-003-TAP (560071) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT07-PO2	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to TATONGA7 (515407) 345kV line CKT 2;** 3 phase fault on WWDEHV-T2 345kV (515375)/138kV (515376)/13.8kV (515799) transformer CKT 2, near WWDEHV7 345kV. a. Apply fault at the WWDEHV7 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9013-PO2	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to TATONGA7 (515407) 345kV line CKT 2;** 3 phase fault on the BORDER 7 (515458) to TUCO_INT 7 (525832) 345kV line CKT 1, near BORDER 7. a. Apply fault at the BORDER 7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT9016-PO2	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to TATONGA7 (515407) 345kV line CKT 2;** 3 phase fault on the WWRDEHV7 (515375) to G16-003-TAP (560071) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT03-PO4	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to BORDER 7 (515458) 345kV line CKT 1;** 3 phase fault on the WWRDEHV7 (515375) to DGRASSE7 (515852) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT06-PO4	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to BORDER 7 (515458) 345kV line CKT 1;** 3 phase fault on the WWRDEHV7 (515375) to TATONGA7 (515407) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT07-PO4	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to BORDER 7 (515458) 345kV line CKT 1;** 3 phase fault on WWDEHV-T2 345kV (515375)/138kV (515376)/13.8kV (515799) transformer CKT 2, near WWDEHV7 345kV. a. Apply fault at the WWDEHV7 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9016-PO4	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to BORDER 7 (515458) 345kV line CKT 1;** 3 phase fault on the WWRDEHV7 (515375) to G16-003-TAP (560071) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT03-PO5	P6	**PRIOR OUTAGE of WWDEHV-T2 345kV (515375)/138kV (515376)/13.8kV (515795) transformer CKT 1;** 3 phase fault on the WWRDEHV7 (515375) to DGRASSE7 (515852) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT06-PO4	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to BORDER 7 (515458) 345kV line CKT 1;** 3 phase fault on the WWRDEHV7 (515375) to TATONGA7 (515407) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT07-PO4	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to BORDER 7 (515458) 345kV line CKT 1;** 3 phase fault on WWDEHV-T2 345kV (515375)/138kV (515376)/13.8kV (515799) transformer CKT 2, near WWDEHV7 345kV. a. Apply fault at the WWDEHV7 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9016-PO4	P6	**PRIOR OUTAGE of WWRDEHV7 (515375) to BORDER 7 (515458) 345kV line CKT 1;** 3 phase fault on the WWRDEHV7 (515375) to G16-003-TAP (560071) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT03-PO5	P6	**PRIOR OUTAGE of WWDEHV-T2 345kV (515375)/138kV (515376)/13.8kV (515795) transformer CKT 1;** 3 phase fault on the WWRDEHV7 (515375) to DGRASSE7 (515852) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT06-PO5	P6	**PRIOR OUTAGE of WWDEHV-T2 345kV (515375)/138kV (515376)/13.8kV (515795) transformer CKT 1;** 3 phase fault on the WWRDEHV7 (515375) to TATONGA7 (515407) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT07-PO5	P6	**PRIOR OUTAGE of WWDEHV-T2 345kV (515375)/138kV (515376)/13.8kV (515795) transformer CKT 1;** 3 phase fault on WWDEHV-T2 345kV (515375)/138kV (515376)/13.8kV (515799) transformer CKT 2, near WWDEHV7 345kV. a. Apply fault at the WWDEHV7 345kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT44-PO5	P6	**PRIOR OUTAGE of WWDEHV-T2 345kV (515375)/138kV (515376)/13.8kV (515795) transformer CKT 1;** 3 phase fault on the WWRDEHV7 (515375) to BORDER 7 (515458) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT9013-PO5	P6	**PRIOR OUTAGE of WWDEHV-T2 345kV (515375)/138kV (515376)/13.8kV (515795) transformer CKT 1;** 3 phase fault on the BORDER 7 (515458) to TUCO_INT 7 (525832) 345kV line CKT 1, near BORDER 7. a. Apply fault at the BORDER 7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT9016-PO5	P6	**PRIOR OUTAGE of WWDEHV-T2 345kV (515375)/138kV (515376)/13.8kV (515795) transformer CKT 1;** 3 phase fault on the WWRDEHV7 (515375) to G16-003-TAP (560071) 345kV line CKT 1, near WWRDEHV7. a. Apply fault at the WWRDEHV7 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT01-PO6	P6	**PRIOR OUTAGE of G16-003-TAP (560071) to BADGER 7 (515677) 345kV line CKT 2;** 3 phase fault on the G16-003-TAP (560071) to BADGER 7 (515677) 345kV line CKT 1, near G16-003-TAP. a. Apply fault at the G16-003-TAP 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT02-PO6	P6	**PRIOR OUTAGE of G16-003-TAP (560071) to BADGER 7 (515677) 345kV line CKT 2;** 3 phase fault on the G16-003-TAP (560071) to WWRDEHV7 (515375) 345kV line CKT 1, near G16-003-TAP. a. Apply fault at the G16-003-TAP 345kV bus. b. Clear fault after 6 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 6 cycles, then trip the line in (b) and remove fault.
FLT1001-SB	P4	**Stuck Breaker on BADGER (515677) 345kV bus.** a. Apply single-phase fault at BADGER (515677) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the BADGER (515677) to G16-003-TAP (560071) 345 kV line CKT 1. d. Trip the BADGER (515677) to GEN-2011-014 (515686) line CKT 1. **Trip generator G11-014-GEN2 (515682).** **Trip generator G11-014-GEN1 (515678).**
FLT1002-SB	P4	**Stuck Breaker on BADGER (515677) 345kV bus.** a. Apply single-phase fault at BADGER (515677) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the BADGER (515677) to G16-003-TAP (560071) 345 kV line CKT 2. d. Trip the BADGER (515677) to GEN-2011-014 (515686) line CKT 1. **Trip generator G11-014-GEN2 (515682).** **Trip generator G11-014-GEN1 (515678).**

6.3 Results

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

Table 6-2: GEN-2016-003 Dynamic Stability Results

Fault ID	19WP			21LL			21SP			26SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT01-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT04-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT05-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT06-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT08-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT09-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT10-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT12-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT13-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT14-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT15-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT16-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT23-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT44-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT45-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT46-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT47-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT06-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT32-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT14-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT15-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT17-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT19-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 Continued

Fault ID	19WP			21LL			21SP			26SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT01-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT06-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT44-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 Continued

Fault ID	19WP			21LL			21SP			26SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT06-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT44-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT06-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT44-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT06-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT03-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT06-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT44-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT01-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO6	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

There were no damping or voltage recovery violations attributed to the GEN-2016-003 project 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 Modified Capacity Exceeds GIA Capacity

Under FERC Order 845, Interconnection Customers are allowed to request Interconnection Service that is lower than the full generating capacity of their planned generating facilities. The Interconnection Customers must install acceptable control and protection devices that prevent the injection above their requested Interconnection Service amount measured at the POI.

As such, Interconnection Customers are allowed to increase the generating capacity of a generating facility without increasing its Interconnection Service amount stated in its GIA. This is allowable as long as they install the proper control and protection devices, and the requested modification is not determined to be a Material Modification.

7.1 Results

The modified generating capacity of GEN-2016-003 (250 MW) exceeds the GIA Interconnection Service amount, 248.4 MW, as listed in Appendix A of the GIA.

The customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

8.0 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 them being implemented and inform the Interconnection Customer in writing of whether the modifications would constitute a Material Modification. Material Modification shall mean (1) modification to an Interconnection Request in the queue that has a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date; or (2) planned modification to an Existing Generating Facility that is undergoing evaluation for a Generating Facility Modification or Generating Facility Replacement, and has a material adverse impact on the Transmission System with respect to: i) steady-state thermal or voltage limits, ii) dynamic system stability and response, or iii) short-circuit capability limit; compared to the impacts of the Existing Generating Facility prior to the modification or replacement.

8.1 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 did not negatively impact the prior study dynamic stability and short circuit results, and the modifications to the project were not significant enough to change the previously studied power flow conclusions.

This determination implies that any network upgrades already required by GEN-2016-003 would not be negatively impacted and that no new upgrades are required due to the requested modification, thus not resulting in a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date.

9.0 Conclusions

The Interconnection Customer for GEN-2016-003 requested a Modification Request Impact Study to assess the impact of the turbine and facility change to 59 x Vestas 4.2 MW + 1 x Vestas 2.2 MW for a total combined capacity of 250 MW. The combined generating capacity of GEN-2016-003 (250 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 248.4 MW, as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI.

In addition, the modification request included changes to the collection system, generator step-up transformers, generation interconnection line rating, main substation transformers, and reactive power devices.

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.58% compared to the DISIS-2017-001 power flow models. However, SPP determined that while the modification used the same turbine manufacturer, Vestas, the change in stability model from CP20065718 to a combination of CP200653400 and VC200453400 required short circuit and dynamic stability analysis.

All analyses were performed using the PTI PSS/E version 33 software and the results are summarized below.

The results of the charging current compensation analysis performed using the 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak models showed that the GEN-2016-003 project needed 11.95 MVAr of reactor shunts on the 34.5 kV bus of the project substation with the modifications in place, an increase from the 7.6 MVAr found in the previous modification study[4]. 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 Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

The results from the short circuit analysis with the updated configuration showed that the maximum GEN-2016-003 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2016-003 POI was not greater than 0.37 kA for the 2021SP and 2028SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-003 generators online were below 46 kA for the 2021SP and 2028SP models.

The dynamic stability analysis was performed using PTI PSS/E version 33.10 software for the four modified study models, 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak. Up to 81 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults.

There were no damping or voltage recovery violations attributed to the GEN-2016-003 project observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies

[4] GEN-2016-003 Modification Request Impact Study – March 10, 2021

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 adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date. As the requested modification places the generating capacity of the Interconnection Request at a higher amount than its Interconnection Service, the customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

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.