Submitted to

Southwest Power Pool

Report On

GEN-2003-004, GEN-2004-023, and GEN-2005-003 Modification Request Impact Study

Revision R1

Date of Submittal
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anedenconsulting.com

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPENDICES

Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
06/22/2021	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-2003-004, GEN-2004-023, and GEN-2005-003, three active Generation Interconnection Requests (GIR) with a point of interconnection (POI) at the Washita 138 kV Substation.

The GEN-2003-004, GEN-2004-023, and GEN-2005-003 projects are proposed to interconnect in the Western Farmers Electric Cooperative (WFEC) control area with a combined capacity of 151.2 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2003-004, GEN-2004-023, & GEN-2005-003 to change the turbine configuration to 66 x Vestas V110 Mk10D 2.0 MW + 7 x Vestas V110 Mk10C 2.0 MW + 2 x Vestas V90 1.815 MW + 1 x Vestas V100 1.815 MW + 7 x Vestas V80 1.807 MW for a total generating capacity of 164.094 MW. The generating capacity for GEN-2003-004, GEN-2004-023, and GEN-2005-003 (164.094 MW) exceeds the total Generator Interconnection Agreement (GIA) Interconnection Service amount, 151.2 MW, as listed in Appendix A. 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 power injected into the POI. The project dispatch was reduced to the GIA amount by incrementally turning off Vestas V80 1.807 MW generators. The project was modeled such that the POI injection was at or below 151.2 MW while the nearby POI projects GEN-2001-026 and GEN-2008-037 were offline and disconnected.

In addition, the modification request included changes to the collection system, generator step-up transformers, and main substation transformer. The existing and modified configuration for GEN-2003-004, GEN-2004-023, and GEN-2005-003 are shown in Table ES-2.

Table ES-1: GEN-2003-004, GEN-2004-023, & GEN-2005-003 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2003-004	Washita 138 kV (521089)	81 x Vestas V80 1.8 MW + 2 x Vestas V90 1.8 MW + 1 x Vestas V100 1.8 MW = 151.2 MW	100.0
GEN-2004-023	Washita 138 kV (521089)		20.6
GEN-2005-003	Washita 138 kV (521089)		30.6
		Total Combined Capacity	151.2

Table ES-2: GEN-2003-004, GEN-2004-023, & GEN-2005-003 Modification Request

<table>
<tr><th>Facility</th><th colspan="2">Existing</th><th colspan="5">Modification</th></tr>
<tr><td>Point of Interconnection</td><td colspan="2">Washita 138 kV (521089)</td><td colspan="5">Washita 138 kV (521089)</td></tr>
<tr><td>Configuration/Capacity</td><td colspan="2">81 x Vestas V80 1.8 MW + 2 x Vestas V90 1.8 MW + 1 x Vestas V100 1.8 MW = 151.2 MW</td><td colspan="5">66 x Vestas V110 Mk10D 2.0 MW + 7 x Vestas V110 Mk10C 2.0 MW + 2 x Vestas V90 1.815 MW + 1 x Vestas V100 1.815 MW + 7 x Vestas V80 1.807 MW = 164.094 MW
PPC to limit POI Injection to 151.2 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td><u>BC SW 4 to Silk Hills 138 kV:</u>
Length = 4.6 miles
R = 0.001650 pu
X = 0.017499 pu
B = 0.005231 pu</td><td><u>Silk Hills to Washita 138 kV:</u>
Length = 19.35 miles
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X = 0.073609 pu
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Winding MVA = 200 MVA,
Rating MVA = 0 MVA</td><td colspan="5">X = 8.715%, R = 0.234%,
Winding MVA = 96 MVA,
Rating MVA = 160 MVA</td></tr>
<tr><td>Equivalent GSU Transformer[1]</td><td colspan="2">Gen 1 Equivalent Qty: 84:
X = 4.826%, R = 0.0%,
Winding MVA= 200 MVA,
Rating MVA = 0 MVA</td><td>Gen 1 Equivalent Qty: 7:
X = 9.759%, R = 0.895%, Winding MVA= 16.1 MVA,
Rating MVA = 16.1 MVA</td><td>Gen 2 Equivalent Qty: 66:
X = 9.759%, R = 0.895%, Winding MVA= 151.8 MVA,
Rating MVA = 151.8 MVA</td><td>Gen 3 Equivalent Qty: 1:
X = 8.963%, R = 0.816%, Winding MVA= 1.9 MVA,
Rating MVA = 1.9 MVA</td><td>Gen 4 Equivalent Qty: 2:
X = 8.963%, R = 0.816%, Winding MVA= 3.8 MVA,
Rating MVA = 3.8 MVA</td><td>Gen 5 Equivalent Qty: 7:
X = 6.369%, R = 0.631%, Winding MVA= 13.3 MVA,
Rating MVA = 13.3 MVA</td></tr>
<tr><td>Equivalent Collector Line[2]</td><td colspan="2">N/A</td><td colspan="5">R = 0.007435 pu
X = 0.008052 pu
B = 0.060947 pu</td></tr>
<tr><td>Reactive Power Devices</td><td colspan="2">2 x 6 MVAR 34.5 kV Capacitor Bank</td><td colspan="5">2 x 6 MVAR 34.5 kV Capacitor Bank</td></tr>
</table>

1) X and R based on Winding MVA, 2) all pu values are on 100 MVA Base

SPP determined that power flow should not be performed based on the POI MW injection increase of 1.55% compared to the recently studied DISIS-2017-001 power flow models. However, SPP determined that while the modification used the same turbine manufacturer, Vestas, short circuit and dynamic stability analyses were required because of the project capacity increase and the use of a PPC.

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-2016-002-2 Group 7 study models:

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

Aneden updated the GIRs that had POIs within 3 buses of the GEN-2003-004, GEN-2004-023, and GEN-2005-003 POI as applicable based on SPP's confirmation of the latest project configurations. Modeling updates for GEN-2007-043, GEN-2014-056, and GEN-2015-057 were included in the base models. 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-2003-004, GEN-2004-023, and GEN-2005-003 project needed a combined 8.83 MVAr of reactor shunts on the 34.5 kV bus of the project substations, an increase from the 2.7 MVAr found for the existing GEN-2003-004, GEN-2004-023, and GEN-2005-003 configuration. 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 topology showed that the maximum GEN-2003-004, GEN-2004-023, and GEN-2005-003 contribution to three-phase fault currents in the immediate systems at or near GEN-2003-004, GEN-2004-023, and GEN-2005-003 was not greater than 0.35 kA for the 2018SP and 2026SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2003-004, GEN-2004-023, and GEN-2005-003 generators online were below 44 kA for the 2018SP and 2026SP models.

The dynamic stability analysis was performed using the three modified study models 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak. Up to 82 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.

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 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.

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-2003-004, GEN-2004-023, and GEN-2005-003. A Modification Request Impact Study (MRIS) 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 most recently studied DISIS-2017-001 power flow 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 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-2003-004, GEN-2004-023, and GEN-2005-003 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a point of interconnection (POI) at the Washita 138 kV Substation. At the time of the posting of this report, GEN-2003-004, GEN-2004-023, and GEN-2005-003 are active Interconnection Requests with queue statuses of "IA FULLY EXECUTED/COMMERCIAL OPERATION." GEN-2003-004, GEN-2004-023, and GEN-2005-003 are wind farms, and have maximum summer and winter queue capacities of 100 MW, 20.6 MW, and 30.6 MW respectively with Energy Resource Interconnection Service (ERIS).

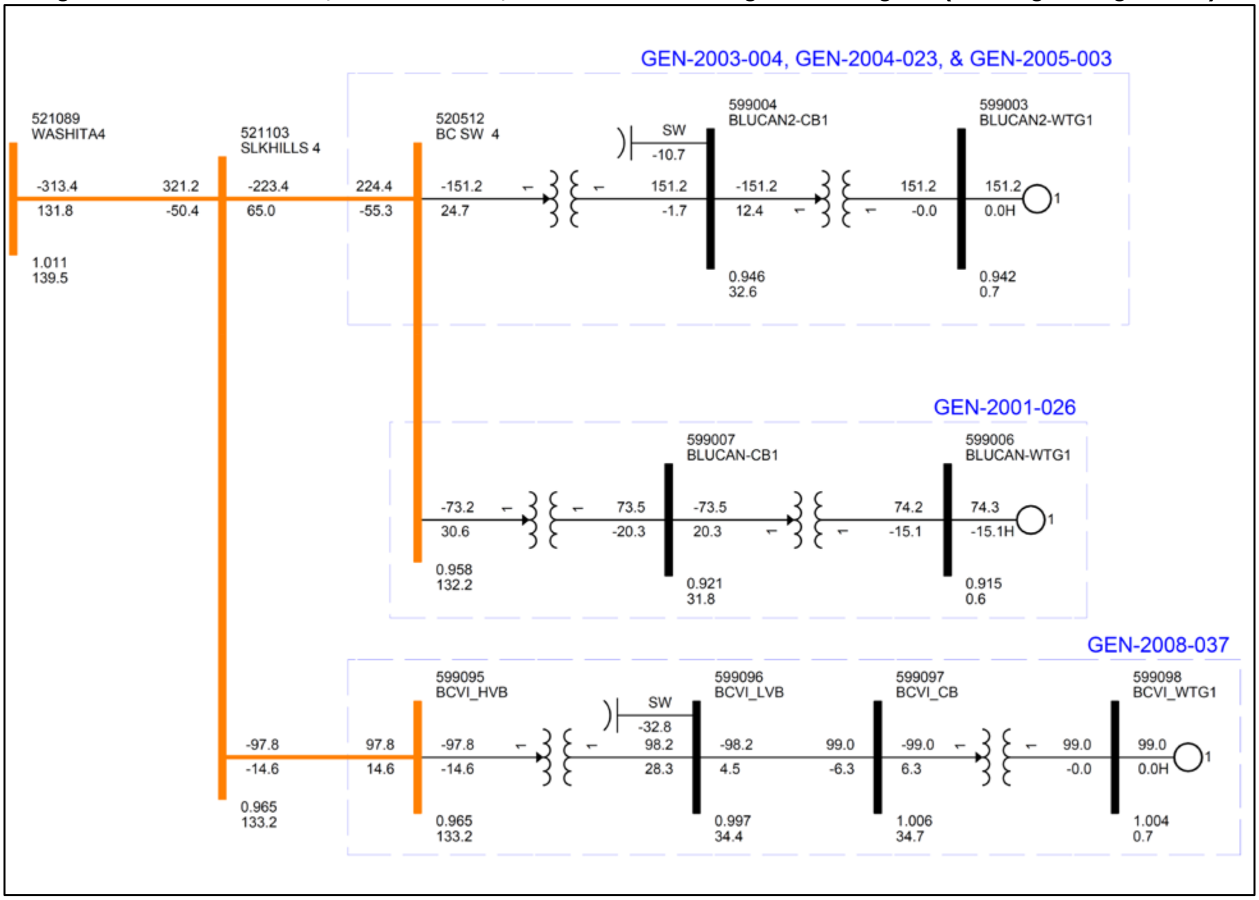
The GEN-2003-004, GEN-2004-023, and GEN-2005-003 projects were originally studied as individual impact studies. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2003-004, GEN-2004-023, and GEN-2005-003 configuration.

The GEN-2003-004, GEN-2004-023, and GEN-2005-003 projects are proposed to interconnect in the Western Farmers Electric Cooperative (WFEC) control area with a combined capacity of 151.2 MW as shown in Table 2-1 below.

Table 2-1: GEN-2003-004, GEN-2004-023, & GEN-2005-003 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2003-004	Washita 138 kV (521089)	81 x Vestas V80 1.8 MW + 2 x Vestas V90 1.8 MW + 1 x Vestas V100 1.8 MW = 151.2 MW	100.0
GEN-2004-023	Washita 138 kV (521089)		20.6
GEN-2005-003	Washita 138 kV (521089)		30.6
		Total Combined Capacity	151.2

Figure 2-1: GEN-2003-004, GEN-2004-023, & GEN-2005-003 Single Line Diagram (Existing Configuration)



This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2003-004, GEN-2004-023, & GEN-2005-003 to change the turbine configuration to 66 x Vestas V110 Mk10D 2.0 MW + 7 x Vestas V110 Mk10C 2.0 MW + 2 x Vestas V90 1.815 MW + 1 x Vestas V100 1.815 MW + 7 x Vestas V80 1.807 MW for a total generating capacity of 164.094 MW. The requested modification includes the use of a Power Plant Controller (PPC) to limit the power injected into the POI. In addition, the modification request included changes to the collection system, generator step-up transformers, and main substation transformer. Figure 2-2 shows the power flow model single line diagram for the GEN-2003-004, GEN-2004-023, and GEN-2005-003 modification. The existing and modified configurations for GEN-2003-004, GEN-2004-023, and GEN-2005-003 are shown in Table 2-2.

The modified generating capacity of GEN-2003-004, GEN-2004-023, and GEN-2005-003 (164.094 MW) exceeds the GIA Interconnection Service amount, 151.2 MW. The project dispatch was reduced to the GIA amount by incrementally turning off Vestas V80 1.807 MW generators. The project was modeled such that the POI injection was at or below 151.2 MW while the nearby POI projects GEN-2001-026 and GEN-2008-037 were offline and disconnected.

Figure 2-2: GEN-2003-004, GEN-2004-023, & GEN-2005-003 Single Line Diagram (Modification Configuration)

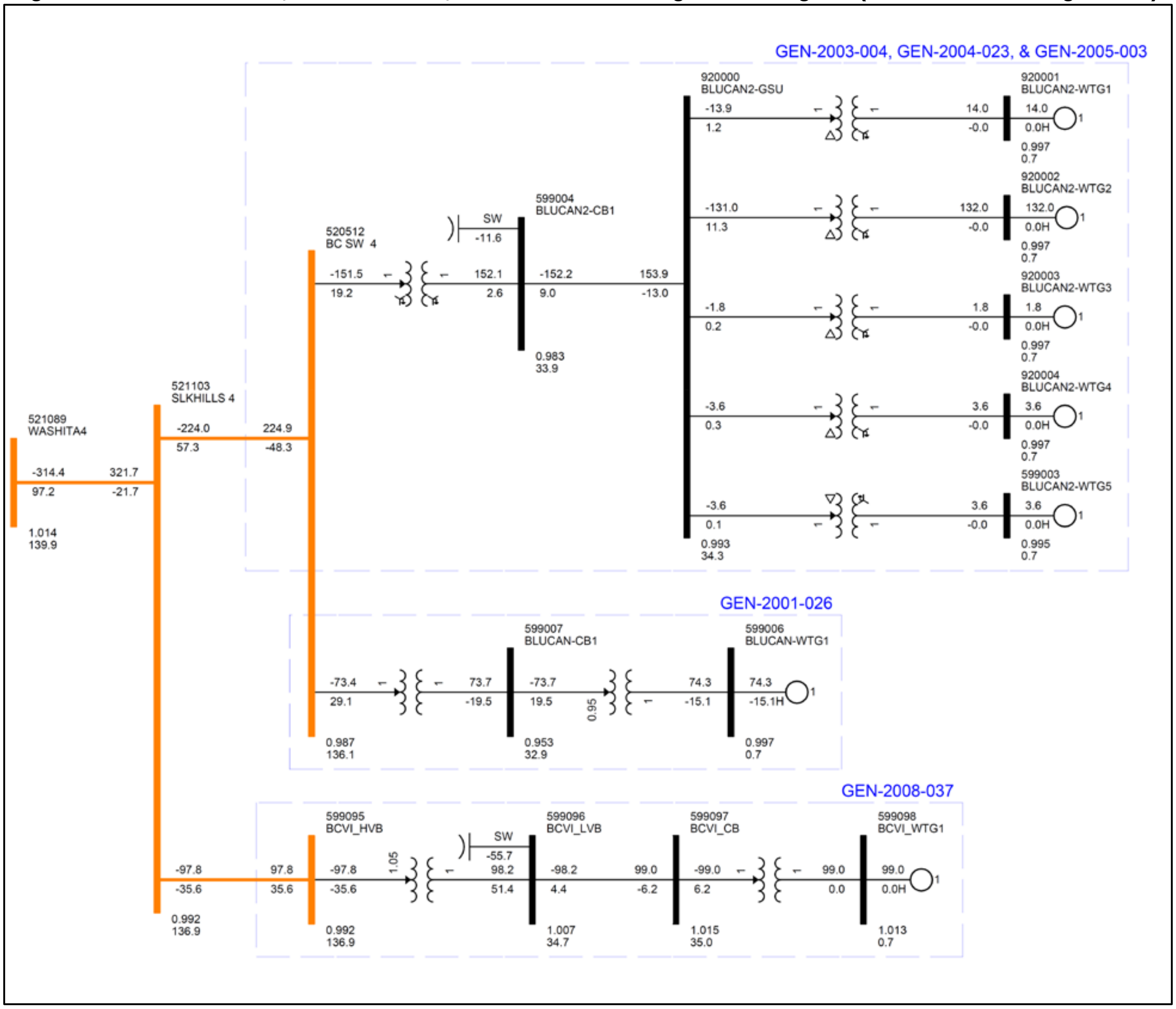


Table 2-2: GEN-2003-004, GEN-2004-023, & GEN-2005-003 Modification Request

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1) X and R based on Winding MVA, 2) all pu values are on 100 MVA Base

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-2016-002-2 Group 7 study models. Aneden updated the GIRs that had POIs within 3 buses of the GEN-2003-004, GEN-2004-023, and GEN-2005-003 POI as applicable based on SPP's confirmation of the latest project configurations. Modeling updates for GEN-2007-043, GEN-2014-056, and GEN-2015-057 were included in the base 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 to compare the most recently studied DISIS-2017-001 power flow configuration and the requested modifications with the PPC in place for GEN-2003-004, GEN-2004-023, and GEN-2005-003. The percentage change in the POI injection 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 1.55%) 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. The MW shown include injections from both the GEN-2003-004, GEN-2004-023, and GEN-2005-003 project and nearby projects GEN-2001-026 and GEN-2008-037 which share gen-tie lines with GEN-2003-004, GEN-2004-023, and GEN-2005-003.

Table 3-1: GEN-2003-004, GEN-2004-023, & GEN-2005-003 POI Injection Comparison

Interconnection Request	DISIS-2017-001 Powerflow POI Injection from Combined Projects (MW)	MRIS POI Injection from Combined Projects w/ PPC (MW)	POI Injection Difference from Combined Projects %
GEN-2003-004, GEN-2004-023, & GEN-2005-003	309.6*	314.4*	1.55%

*This total MW amount includes the GEN-2001-026 and GEN-2008-037 projects which share gen-tie lines

3.2 Turbine Parameters Comparison

SPP determined that while the modification used the same turbine manufacturer, Vestas, the increase in the project capacity and the use of the PPC caused the need for short circuit and dynamic stability analyses as the 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

Since 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-2003-004, GEN-2004-023, & GEN-2005-003 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 nearby projects GEN-2001-026 and GEN-2008-037 were switched offline and disconnected for this analysis as they share gen-tie lines with GEN-2003-004, GEN-2004-023, and GEN-2005-003. The GEN-2003-004, GEN-2004-023, and GEN-2005-003 generators were then 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 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-2003-004, GEN-2004-023, and GEN-2005-003 projects needed approximately 8.83 MVAr of compensation at its project substations, to reduce the POI MVAr to zero. This is an increase from the combined 2.7 MVAr found for the existing GEN-2003-004, GEN-2004-023, and GEN-2005-003 configuration. Figure 4-1 illustrates the shunt reactor sizes needed to reduce the POI MVAr to approximately zero with the existing configuration. Figure 4-2 illustrates the shunt reactor sizes needed to reduce the POI MVAr to approximately zero with the updated topology. The final shunt reactor requirements for GEN-2003-004, GEN-2004-023, and GEN-2005-003 are shown in Table 4-1.

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)		
			17WP	18SP	26SP
GEN-2003-004, GEN-2004-023, & GEN-2005-003	521089	Washita 138 kV	8.83	8.83	8.83

Figure 4-1: GEN-2003-004, GEN-2004-023, & GEN-2005-003 Single Line Diagram (Existing Shunt Reactor)

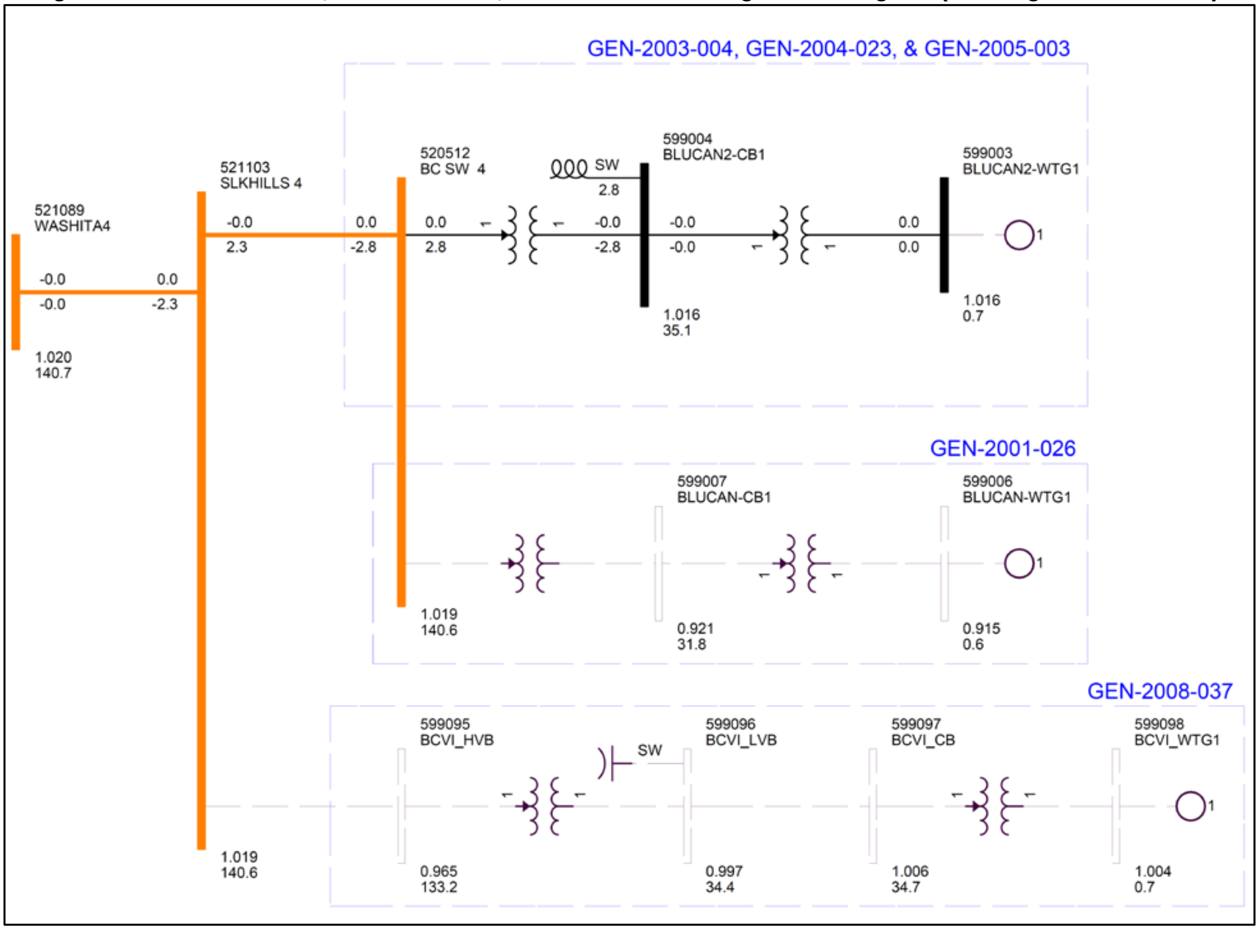
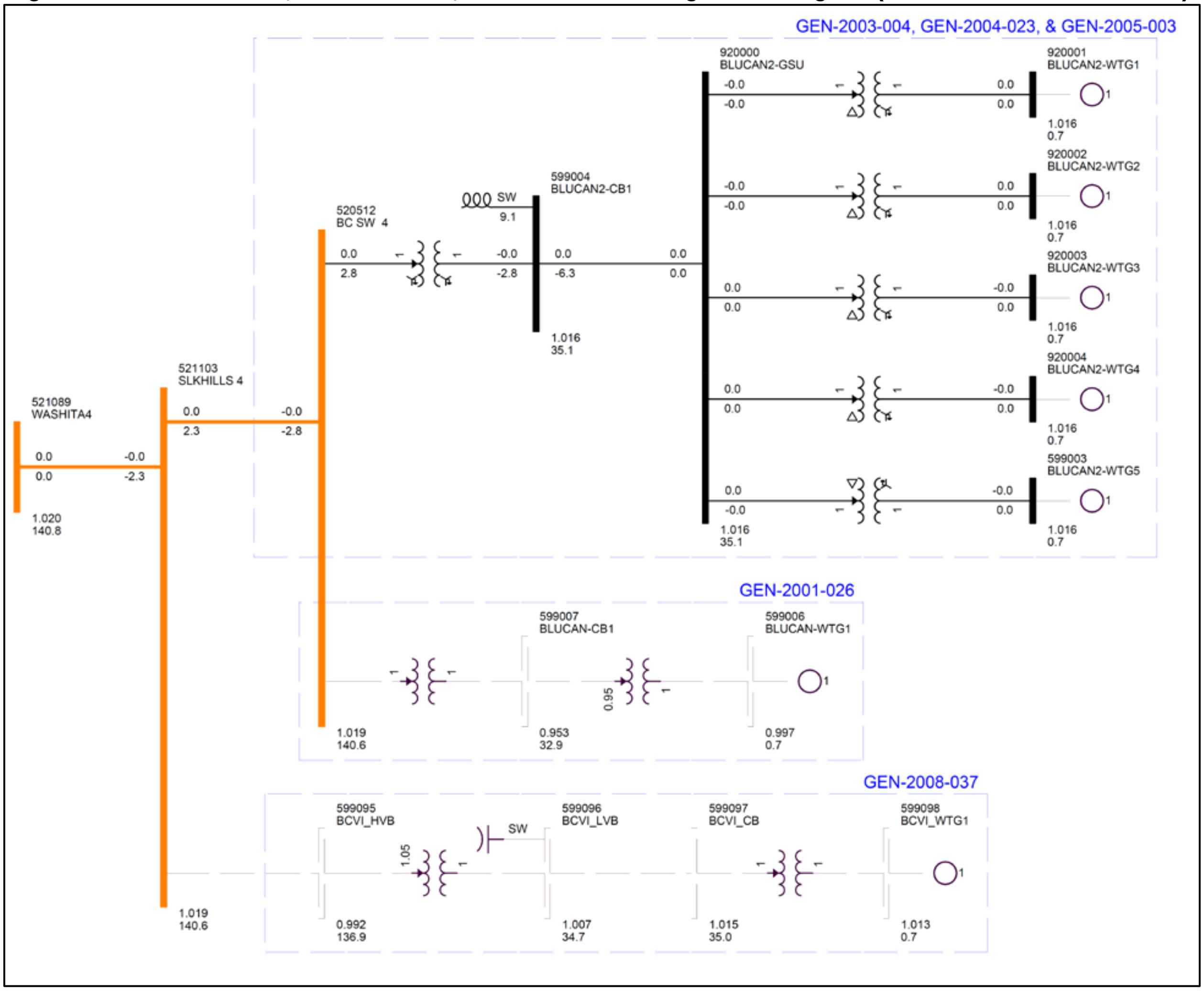


Figure 4-2: GEN-2003-004, GEN-2004-023, & GEN-2005-003 Single Line Diagram (Modification Shunt Reactor)



5.0 Short Circuit Analysis

A short circuit study was performed using the 2018SP and 2026SP models for GEN-2003-004, GEN-2004-023, and GEN-2005-003. 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 138 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-2003-004, GEN-2004-023, and GEN-2005-003 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-2003-004, GEN-2004-023, and GEN-2005-003 POI bus fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 27.98 kA with the GEN-2003-004, GEN-2004-023, and GEN-2005-003 project online.

The maximum fault current calculated within 5 buses of the GEN-2003-004, GEN-2004-023, and GEN-2005-003 POI was less than 44 kA for the 2018SP and 2026SP models respectively. The maximum GEN-2003-004, GEN-2004-023, and GEN-2005-003 contribution to three-phase fault current was about 6.1% and 0.35 kA.

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
2018SP	27.87	27.97	0.11	0.4%
2026SP	27.87	27.98	0.11	0.4%

Table 5-2: 2018SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	18.9	0.00	0.0%
138	43.1	0.35	6.1%
230	7.3	-0.01	-0.2%
345	32.9	-0.01	0.0%
Max	**43.1**	**0.35**	**6.1%**

Table 5-3: 2026SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	18.9	0.00	0.0%
138	42.7	0.34	6.1%
230	7.3	-0.01	-0.1%
345	32.8	0.00	0.0%
Max	**42.7**	**0.34**	**6.1%**

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-2003-004, GEN-2004-023, and GEN-2005-003 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-2003-004, GEN-2004-023, and GEN-2005-003 configuration of 66 x Vestas V110 Mk10D 2.0 MW (VS20045709) + 7 x Vestas V110 Mk10C 2.0 MW (VS17095710) + 2 x Vestas V90 1.815 MW (VS17095710) + 1 x Vestas V100 1.815 MW (VS17095710) + 7 x Vestas V80 1.807 MW (VS20045709). The requested modification included the use of a PPC (PPCORE530V5710) to limit the power injected into the POI to below the GIA amount. This stability analysis was performed using PTI's PSS/E version 33.7 software.

The stability models were developed using the DISIS-2016-002-2 Group 7 models. The modifications requested for the GEN-2003-004, GEN-2004-023, and GEN-2005-003 projects were used to create modified stability models for this impact study. Aneden updated the GIRs that had POIs within 3 buses of the GEN-2003-004, GEN-2004-023, and GEN-2005-003 POI as applicable based on SPP's confirmation of the latest project configurations. Modeling updates for GEN-2007-043, GEN-2014-056, and GEN-2015-057 were included in the base models. In addition, the following system adjustments were made to address existing base case issues:

1. GEN-2008-037 34.5 kV capbanks switched online
2. GEN-2001-026 GSU tap ratio was adjusted to 0.95
3. Dempsey Units' Low Voltage Ride Through (LVRT) CON(J+10) generator model setting was changed from 0.04 seconds to 0.15 seconds on both units
4. Elk City 69 kV capbank switched online
5. Carter 69 kV capbank switched online

The modified dynamics model data for the GEN-2003-004, GEN-2004-023, and GEN-2005-003 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-2003-004, GEN-2004-023, and GEN-2005-003 and other equally and prior queued projects in Group 7. In addition, voltages of five (5) buses away from the POI of GEN-2003-004, GEN-2004-023, and GEN-2005-003 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-2003-004, GEN-2004-023, and GEN-2005-003 and selected additional fault events for GEN-2003-004, GEN-2004-023, and GEN-2005-003 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.

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT05-3PH	P1	3 phase fault on the Southwester Station (511477) to ANADARK4 (520814) 138kV line CKT 1, near Southwester Station. a. Apply fault at the Southwester Station 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT06-1PH	P1	1 phase fault on the Southwester Station (511477) to ANADARK4 (520814) 138kV line CKT 1, near Southwester Station. a. Apply fault at the Southwester Station 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT11-3PH	P1	3 phase fault on the WASHITA4 (521089) to ONEY 4 (521017) 138kV line CKT 1, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT12-1PH	P1	1 phase fault on the WASHITA4 (521089) to ONEY 4 (521017) 138kV line CKT 1, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT13-3PH	P1	3 phase fault on the ONEY 4 (521017) to BINGERJ4 (520827) 138kV line CKT 1, near ONEY 4. a. Apply fault at the ONEY 4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT14-1PH	P1	1 phase fault on the ONEY 4 (521017) to BINGERJ4 (520827) 138kV line CKT 1, near ONEY 4. a. Apply fault at the ONEY 4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT15-3PH	P1	3 phase fault on the WASHITA4 (521089) to Southwester Station (511477) 138kV line CKT 1, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT16-1PH	P1	1 phase fault on the WASHITA4 (521089) to Southwester Station (511477) 138kV line CKT 1, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9001-3PH	P1	3 phase fault on the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 1, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	P1	3 phase fault on the WASHITA 138/69/13.8kV (521089 /521088 /521179) transformer CKT 1, near WASHITA 138kV. a. Apply fault at the WASHITA 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9003-3PH	P1	3 phase fault on the BINGERJ4 (520827) to SICKLES4 (521050) 138kV line CKT 1, near BINGERJ4. a. Apply fault at the BINGERJ4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9004-3PH	P1	3 phase fault on the BINGERJ4 (520827) to NIJECT 4 (521010) 138kV line CKT 1, near BINGERJ4. a. Apply fault at the BINGERJ4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1	3 phase fault on the GRACMNT3 138/345/13.8kV (515802 /515800 /515801) transformer CKT 1, near GRACMNT 138kV. a. Apply fault at the GRACMNT 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9006-3PH	P1	3 phase fault on the GRACMNT3 (515802) to ANADARK4 (520814) 138kV line CKT 1, near GRACMNT3. a. Apply fault at the GRACMNT3 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9007-3PH	P1	3 phase fault on the GRACMNT7 (515800) to MINCO (514801) 345kV line CKT 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	P1	3 phase fault on the GRACMNT7 (515800) to CHISHOLM7 (511553) 345kV line CKT 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9009-3PH	P1	3 phase fault on the GRACMNT7 (515800) to GEN-2015-093 (585270) 345kV line CKT 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault. **Trip generator G15-093-GEN1 (585273).** **Trip generator G15-093-GEN2 (585274).**
FLT9010-3PH	P1	3 phase fault on the GRACMNT7 (515800) to G16-091-TAP (587744) 345kV line CKT 1, near GRACMNT7. a. Apply fault at the GRACMNT7 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9011-3PH	P1	3 phase fault on the G16-091-TAP (587744) to L.E.S - 7 (511468) 345kV line CKT 1, near G16-091-TAP. a. Apply fault at the G16-091-TAP 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9012-3PH	P1	3 phase fault on the MINCO (514801) to CIMARON7 (514901) 345kV line CKT 1, near MINCO. a. Apply fault at the MINCO 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9013-3PH	P1	3 phase fault on the MINCO (514801) to MNCWND37 (515549) 345kV line CKT 1, near MINCO. a. Apply fault at the MINCO 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault. **Trip Generators MINCO-WTG3 (599117), G14-056-GEN1 (515943), G14-056-GEN2 (584064), G14-056-GEN3 (584067), G15-057-GEN1 (584953), G15-057-GEN2 (584954), G15-057-GEN3 (584955).**

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9014-3PH	P1	3 phase fault on the MINCO (514801) to MCNOWND7 (515444) 345kV line CKT 1, near MINCO. a. Apply fault at the MINCO 345 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault. **Trip generator MINCO-WTG1 (599062).**
FLT9015-3PH	P1	3 phase fault on the CHISHOLM7 345/230/13.2kV (511553 /511557 /511558) transformer CKT 1, near CHISHOLM7 345kV. a. Apply fault at the CHISHOLM7 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9016-3PH	P1	3 phase fault on the Southwester Station (511477) to VERDEN 4 (511421) 138kV line CKT 1, near Southwester Station. a. Apply fault at the Southwester Station 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9017-3PH	P1	3 phase fault on the Southwester Station (511477) to NORGE-4 (511483) 138kV line CKT 1, near Southwester Station. a. Apply fault at the Southwester Station 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9018-3PH	P1	3 phase fault on the Southwester Station (511477) to G16-097-TAP (587794) 138kV line CKT 1, near Southwester Station. a. Apply fault at the Southwester Station 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9019-3PH	P1	3 phase fault on the Southwester Station (511477) to ELSWORTH 4 (511563) 138kV line CKT 1, near Southwester Station. a. Apply fault at the Southwester Station 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9020-3PH	P1	3 phase fault on the Southwester Station (511477) to CARNEG-4 4 (511445) 138kV line CKT 1, near Southwester Station. a. Apply fault at the Southwester Station 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9021-3PH	P1	3 phase fault on the ELSWORTH 4 (511563) to ELGINJT4 (511486) 138kV line CKT 1, near ELSWORTH 4. a. Apply fault at the ELSWORTH 4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9022-3PH	P1	3 phase fault on the CARNEG-4 4 (511445) to HOB-JCT4 (511463) 138kV line CKT 1, near Southwester Station. a. Apply fault at the Southwester Station 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9023-3PH	P1	3 phase fault on the VERDEN 4 (511421) to N29CHIK4 (511502) 138kV line CKT 1, near VERDEN 4. a. Apply fault at the VERDEN 4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9024-3PH	P1	3 phase fault on the NORGE-4 (511483) to CORNVIL4 (511449) 138kV line CKT 1, near NORGE-4. a. Apply fault at the NORGE-4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9025-3PH	P1	3 phase fault on the G16-097-TAP (587794) to FLE TAP4 (511423) 138kV line CKT 1, near G16-097-TAP. a. Apply fault at the G16-097-TAP 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9026-3PH	P1	3 phase fault on the ANADARK4 (520814) to GEORGIA4 (520923) 138kV line CKT 1, near ANADARK4. a. Apply fault at the ANADARK4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9027-3PH	P1	3 phase fault on the ANADARK4 (520814) to HARPER2 (520211) 138kV line CKT 1, near ANADARK4. a. Apply fault at the ANADARK4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9028-3PH	P1	3 phase fault on the ANADARK4 (520814) to SEQUOYAHJ4 (520422) 138kV line CKT 1, near ANADARK4. a. Apply fault at the ANADARK4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9029-3PH	P1	3 phase fault on the ANADARK4 (520814) to POCASET4 (521031) 138kV line CKT 1, near ANADARK4. a. Apply fault at the ANADARK4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9030-3PH	P1	3 phase fault on the ANADARK4 (520814) to BLUCAN5 4 (521129) 138kV line CKT 1, near ANADARK4. a. Apply fault at the ANADARK4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9031-3PH	P1	3 phase fault on the WASHITA4 (521089) to SLKHILLS 4 (521103) 138kV line CKT 1, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault. **Trip generators BCV-WTG1 (599098), BLUCAN-WTG1 (599006), BLUCAN2-WTG1 (920001), BLUCAN2-WTG2 (920002), BLUCAN2-WTG5(599003), BLUCAN2-WTG4(920004), BLUCAN2-WTG3 (920003).**
FLT9032-3PH	P1	3 phase fault on the SLKHILLS 4 (521103) to BCVI_HVB (599095) 138kV line CKT 1, near SLKHILLS 4. a. Apply fault at the SLKHILLS 4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault. **Trip generator BCV-WTG1 (599098).**
FLT9033-3PH	P1	3 phase fault on the SLKHILLS 4 (521103) to BC SW 4 (520512) 138kV line CKT 1, near SLKHILLS 4. a. Apply fault at the SLKHILLS 4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault. **Trip generators BLUCAN-WTG1 (599006), BLUCAN2-WTG1 (920001), BLUCAN2-WTG2 (920002), BLUCAN2-WTG5(599003), BLUCAN2-WTG4(920004), BLUCAN2-WTG3 (920003).**

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9034-3PH	P1	3 phase fault on the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 2, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT15-PO1	P6	**PRIOR OUTAGE of the WASHITA4 (521089) to ONEY 4 (521017) 138kV line CKT 1;** 3 phase fault on the WASHITA4 (521089) to Southwester Station (511477) 138kV line CKT 1, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9001-PO1	P6	**PRIOR OUTAGE of the WASHITA4 (521089) to ONEY 4 (521017) 138kV line CKT 1;** 3 phase fault on the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 1, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9002-PO1	P6	**PRIOR OUTAGE of the WASHITA4 (521089) to ONEY 4 (521017) 138kV line CKT 1;** 3 phase fault on the WASHITA 138/69/13.8kV (521089 /521088 /521179) transformer CKT 1, near WASHITA 138kV. a. Apply fault at the WASHITA 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9034-PO1	P6	**PRIOR OUTAGE of the WASHITA4 (521089) to ONEY 4 (521017) 138kV line CKT 1;** 3 phase fault on the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 2, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT11-PO2	P6	**PRIOR OUTAGE of the WASHITA4 (521089) to Southwester Station (511477) 138kV line CKT 1;** 3 phase fault on the WASHITA4 (521089) to ONEY 4 (521017) 138kV line CKT 1, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9001-PO2	P6	**PRIOR OUTAGE of the WASHITA4 (521089) to Southwester Station (511477) 138kV line CKT 1;** 3 phase fault on the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 1, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9002-PO2	P6	**PRIOR OUTAGE of the WASHITA4 (521089) to Southwester Station (511477) 138kV line CKT 1**; 3 phase fault on the WASHITA 138/69/13.8kV (521089 /521088 /521179) transformer CKT 1, near WASHITA 138kV. a. Apply fault at the WASHITA 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9034-PO2	P6	**PRIOR OUTAGE of the WASHITA4 (521089) to Southwester Station (511477) 138kV line CKT 1;** 3 phase fault on the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 2, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT11-PO3	P6	**PRIOR OUTAGE of the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 2;** 3 phase fault on the WASHITA4 (521089) to ONEY 4 (521017) 138kV line CKT 1, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT15-PO3	P6	**PRIOR OUTAGE of the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 2;** 3 phase fault on the WASHITA4 (521089) to Southwester Station (511477) 138kV line CKT 1, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9001-PO3	P6	**PRIOR OUTAGE of the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 2;** 3 phase fault on the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 1, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9002-PO3	P6	**PRIOR OUTAGE of the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 2;** 3 phase fault on the WASHITA 138/69/13.8kV (521089 /521088 /521179) transformer CKT 1, near WASHITA 138kV. a. Apply fault at the WASHITA 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT11-PO4	P6	**PRIOR OUTAGE of the WASHITA 138/69/13.8kV (521089 /521088 /521179) transformer CKT 1;** 3 phase fault on the WASHITA4 (521089) to ONEY 4 (521017) 138kV line CKT 1, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT15-PO4	P6	**PRIOR OUTAGE of the WASHITA 138/69/13.8kV (521089 /521088 /521179) transformer CKT 1;** 3 phase fault on the WASHITA4 (521089) to Southwester Station (511477) 138kV line CKT 1, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9001-PO4	P6	**PRIOR OUTAGE of the WASHITA 138/69/13.8kV (521089 /521088 /521179) transformer CKT 1;** 3 phase fault on the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 1, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9034-PO4	P6	**PRIOR OUTAGE of the WASHITA 138/69/13.8kV (521089 /521088 /521179) transformer CKT 1;** 3 phase fault on the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 2, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT11-PO5	P6	**PRIOR OUTAGE of the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 1;** 3 phase fault on the WASHITA4 (521089) to ONEY 4 (521017) 138kV line CKT 1, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT15-PO5	P6	**PRIOR OUTAGE of the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 1;** 3 phase fault on the WASHITA4 (521089) to Southwester Station (511477) 138kV line CKT 1, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9002-PO5	P6	**PRIOR OUTAGE of the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 1;** 3 phase fault on the WASHITA 138/69/13.8kV (521089 /521088 /521179) transformer CKT 1, near WASHITA 138kV. a. Apply fault at the WASHITA 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
FLT9034-PO5	P6	**PRIOR OUTAGE of the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 1;** 3 phase fault on the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 2, near WASHITA4. a. Apply fault at the WASHITA4 138 kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT1001-SB	P4	**Stuck Breaker on at GRACMNT4 (515802) at 138kV** a. Apply single-phase fault at GRACMNT4 (515802) on the 138kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the GRACMNT4 (515802) to WASHITA4 (521089) 138kV line CKT 1. d. Trip the GRACMNT3 138/345/13.8kV (515802 /515800 /515801) transformer CKT 1.
FLT1002-SB	P4	**Stuck Breaker on at GRACMNT4 (515802) at 138kV** a. Apply single-phase fault at GRACMNT4 (515802) on the 138kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the GRACMNT3 (515802) to ANADARK4 (520814) 138kV line CKT 1. d. Trip the GRACMNT3 138/345/13.8kV (515802 /515800 /515801) transformer CKT 1.
FLT1003-SB	P4	**Stuck Breaker on at GRACMNT4 (515802) at 138kV** a. Apply single-phase fault at GRACMNT4 (515802) on the 138kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the GRACMNT3 (515802) to ANADARK4 (520814) 138kV line CKT 1. d. Trip the GRACMNT4 (515802) to WASHITA4 (521089) 138kV line CKT 2.
FLT1004-SB	P4	**Stuck Breaker on at GRACMNT4 (515802) at 138kV** a. Apply single-phase fault at GRACMNT4 (515802) on the 138kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the GRACMNT4 (515802) to WASHITA4 (521089) 138kV line CKT 1. d. Trip the GRACMNT4 (515802) to WASHITA4 (521089) 138kV line CKT 2.
FLT1005-SB	P4	**Stuck Breaker on at GRACMNT7 (515800) at 345kV** a. Apply single-phase fault at GRACMNT7 (515800) on the 345kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the GRACMNT7 (515800) to MINCO (514801) 345kV line CKT 1. d. Trip the GRACMNT7 (515800) to G16-091-TAP (587744) 345kV line CKT 1.
FLT1006-SB	P4	**Stuck Breaker on at GRACMNT7 (515800) at 345kV** a. Apply single-phase fault at GRACMNT7 (515800) on the 345kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the GRACMNT3 138/345/13.8kV (515802 /515800 /515801) transformer CKT 1. d. Trip the GRACMNT7 (515800) to G16-091-TAP (587744) 345kV line CKT 1.
FLT1007-SB	P4	**Stuck Breaker on at GRACMNT7 (515800) at 345kV** a. Apply single-phase fault at GRACMNT7 (515800) on the 345kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the GRACMNT7 (515800) to CHISHOLM7 (511553) 345kV line CKT 1. d. Trip the GRACMNT3 138/345/13.8kV (515802 /515800 /515801) transformer CKT 1.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT1008-SB	P4	**Stuck Breaker on at GRACMNT7 (515800) at 345kV** a. Apply single-phase fault at GRACMNT7 (515800) on the 345kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the GRACMNT7 (515800) to MINCO (514801) 345kV line CKT 1. d. Trip the GRACMNT7 (515800) to CHISHOLM7 (511553) 345kV line CKT 1.
FLT1009-SB	P4	**Stuck Breaker at ONEY (521017) at 138kV** a. Apply single phase fault at ONEY (521017) on the 138kV bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the whole bus ONEY (521017).
FLT1010-SB	P4	**Stuck Breaker on at WASHITA4 (521089) at 138kV** a. Apply single-phase fault at WASHITA4 (521089) on the 138kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 1. d. Trip the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 2.
FLT1011-SB	P4	**Stuck Breaker on at WASHITA4 (521089) at 138kV** a. Apply single-phase fault at WASHITA4 (521089) on the 138kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 1. d. Trip the WASHITA4 (521089) to ONEY (521017) 138kV line CKT 1.
FLT1012-SB	P4	**Stuck Breaker on at WASHITA4 (521089) at 138kV** a. Apply single-phase fault at WASHITA4 (521089) on the 138kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the WASHITA 138/69/13.8kV (521089 /521088 /521179) transformer CKT 1. d. Trip the WASHITA4 (521089) to ONEY (521017) 138kV line CKT 1.
FLT1013-SB	P4	**Stuck Breaker on at WASHITA4 (521089) at 138kV** a. Apply single-phase fault at WASHITA4 (521089) on the 138kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the WASHITA4 (521089) to Southwester Station (511477) 138kV line CKT 1. d. Trip the WASHITA4 (521089) to GRACMNT4 (515802) 138kV line CKT 2.
FLT1014-SB	P4	**Stuck Breaker on at Southwester Station (511477) at 138kV** a. Apply single-phase fault at Southwester Station (511477) on the 138kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the Southwester Station (511477) to NORGE-4 (511483) 138kV line CKT 1. d. Trip S.W.S 138/69/13.8kV (511477 /511476 /511413) transformer CKT 1.
FLT1015-SB	P4	**Stuck Breaker on at Southwester Station (511477) at 138kV** a. Apply single-phase fault at Southwester Station (511477) on the 138kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the Southwester Station (511477) to WASHITA4 (521089) 138kV line CKT 1. d. Trip S.W.S 138/13.8/13.8kV (511477 /511849 /511850) transformer CKT 1. **Trip generator SWS NG4 (511849).** **Trip generator SWS NG5 (511850).**
FLT1016-SB	P4	**Stuck Breaker on at Southwester Station (511477) at 138kV** a. Apply single-phase fault at Southwester Station (511477) on the 138kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the Southwester Station (511477) to ANADARK4 (520814) 138kV line CKT 1. d. Trip the Southwester Station (511477) to VERDEN 4 (511421) 138kV line CKT 1.
FLT1017-SB	P4	**Stuck Breaker on at Southwester Station (511477) at 138kV** a. Apply single-phase fault at Southwester Station (511477) on the 138kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the Southwester Station (511477) to CARNEG-4 4 (511445) 138kV line CKT 1. d. Trip S.W.S 138/24kV (511477 /511848) transformer CKT 1. **Trip generator SWS3-1 (511848).**
FLT1018-SB	P4	**Stuck Breaker on at Southwester Station (511477) at 138kV** a. Apply single-phase fault at Southwester Station (511477) on the 138kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the Southwester Station (511477) to G16-097-TAP (587794) 138kV line CKT 1. d. Trip S.W.S 138/14.4kV (511477 /511846) transformer CKT 1. **Trip generator SWS1-1 (511846).**

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT1019-SB	P4	**Stuck Breaker on at Southwester Station (511477) at 138kV** a. Apply single-phase fault at Southwester Station (511477) on the 138kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the Southwester Station (511477) to ELSWORTH 4 (511563) 138kV line CKT 1. d. Trip S.W.S 138/14.4kV (511477 /511847) transformer CKT 1. **Trip generator SWS2-1 (511847).**
FLT1020-SB	P4	**Stuck Breaker on at SLKHILLS 4 (521103) at 138kV** a. Apply single-phase fault at SLKHILLS 4 (521103) on the 138kV bus. b. Clear fault after 16 cycles and remove fault. c. Trip the whole bus SLKHILLS 4 (521103). **Trip generators BCV-WTG1 (599098), BLUCAN-WTG1 (599006), BLUCAN2-WTG1 (920001), BLUCAN2-WTG2 (920002), BLUCAN2-WTG5(599003), BLUCAN2-WTG4(920004), BLUCAN2-WTG3 (920003).**

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-2003-004, GEN-2004-023, & GEN-2005-003 Dynamic Stability Results

Fault ID	17WP			18SP			26SP		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable
FLT05-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT06-1PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT11-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT12-1PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT13-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT14-1PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT15-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT16-1PH	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
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9027-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9028-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9029-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9030-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9031-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9032-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9033-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9034-3PH	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

Table 6-2 continued

Fault ID	17WP			18SP			26SP		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	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
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1011-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1012-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1013-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1014-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1015-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1016-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1017-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1018-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1019-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1020-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT15-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9034-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT11-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9034-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT11-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT15-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT11-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT15-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9034-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT11-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT15-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9034-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 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 which is 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-2003-004, GEN-2004-023, and GEN-2005-003 (164.094 MW) exceeds the GIA Interconnection Service amount, 151.2 MW, as listed in Appendix A.

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 making them 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 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-2003-004, GEN-2004-023, and GEN-2005-003 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-2003-004, GEN-2004-023, and GEN-2005-003 requested a Modification Request Impact Study to assess the impact of the turbine and facility change to a configuration of 66 x Vestas V110 Mk10D 2.0 MW + 7 x Vestas V110 Mk10C 2.0 MW + 2 x Vestas V90 1.815 MW + 1 x Vestas V100 1.815 MW + 7 x Vestas V80 1.807 MW for a total generating capacity of 164.094 MW. The generating capacity for GEN-2003-004, GEN-2004-023, and GEN-2005-003 (164.094 MW) exceeds the total Generator Interconnection Agreement (GIA) Interconnection Service amount, 151.2 MW, as listed in Appendix A. 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 power injected into the POI. The project dispatch was reduced to the GIA amount by incrementally turning off Vestas V80 1.807 MW generators. The project was modeled such that the POI injection was at or below 151.2 MW while the nearby POI projects GEN-2001-026 and GEN-2008-037 were offline and disconnected.

In addition, the modification request included changes to the collection system, generator step-up transformers, and main substation transformer.

SPP determined that power flow should not be performed based on the POI MW injection increase of 1.55% compared to the recently studied DISIS-2017-001 power flow models. However, SPP determined that while the modification used the same turbine manufacturer, Vestas, short circuit and dynamic stability analyses were required because of the project capacity increase and the use of a PPC.

The scope of this modification request study included 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-2003-004, GEN-2004-023, and GEN-2005-003 project needed a combined 8.83 MVAr of reactor shunts on the 34.5 kV bus of the project substations, an increase from the 2.7 MVAr found for the existing GEN-2003-004, GEN-2004-023, and GEN-2005-003 configuration. 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 topology showed that the maximum GEN-2003-004, GEN-2004-023, and GEN-2005-003 contribution to three-phase fault currents in the immediate systems at or near GEN-2003-004, GEN-2004-023, and GEN-2005-003 was not greater than 0.35 kA for the 2018SP and 2026SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2003-004, GEN-2004-023, and GEN-2005-003 generators online were below 44 kA for the 2018SP and 2026SP models.

The dynamic stability analysis was performed using the three modified study models 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak. Up to 82 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.

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 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.

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.