Submitted to
Southwest Power Pool

Report On

GEN-2010-014 and GEN-2011-022 Modification Request Impact Study

Revision R1

Date of Submittal
May 6, 2021

anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
05/06/2021	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-2010-014 and GEN-2011-022, two active Generation Interconnection Requests (GIR) with a point of interconnection (POI) at the Hitchland 345 kV Substation.

The GEN-2010-014 and GEN-2011-022 projects are proposed to interconnect in the Southwestern Public Service Company (SWPS) control area with a combined capacity of 657.8 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2010-014 to change the turbine configuration to 159 x Siemens 2.3 MW for a total generating capacity of 365.7 MW, and GEN-2011-022 to change the turbine configuration to 133 X Siemens 2.3 MW for a total generating capacity of 305.9 MW. The generating capacities for both GEN-2010-014 and GEN-2011-022 (365.7 MW and 305.9 MW) exceed their respective Generator Interconnection Agreement (GIA) Interconnection Service amounts, 358.8 MW and 299 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.

In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformers, and generation interconnection lines. The existing and modified configurations for GEN-2010-014 and GEN-2011-022 are shown in
Table ES-2 and Table ES-3 respectively.

Table ES-1: GEN-2010-014 & GEN-2011-022 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	Capacity (MW)
GEN-2010-014	Hitchland 345 kV (523097)	156 x Siemens 2.3 MW = 358.8 MW	358.8
GEN-2011-022	Hitchland 345 kV (523097)	130 X Siemens 2.3 MW = 299 MW	299.0
		Total Combined Capacity	657.8

Table ES-2: GEN-2010-014 Modification Request

<table>
<tr><th>Facility</th><th colspan="2">Existing</th><th colspan="2">Modification</th></tr>
<tr><td>Point of Interconnection</td><td colspan="2">Hitchland 345 kV (523097)</td><td colspan="2">Hitchland 345 kV (523097)</td></tr>
<tr><td>Configuration/Capacity</td><td colspan="2">156 x Siemens 2.3 MW = 358.8 MW</td><td colspan="2">159 x Siemens 2.3 MW = 365.7 MW with PPC limiting POI injection to 358.8 MW</td></tr>
<tr><td>Generation Interconnection Line (345 kV)</td><td colspan="2">Length = 7.95 miles
R = 0.001150 pu
X = 0.004279 pu
B = 0.053520 pu</td><td colspan="2"><u>Line shared with GEN-2011-022:</u>
Length = 15 miles
R = 0.000735 pu
X = 0.007485 pu
B = 0.126000 pu</td></tr>
<tr><td rowspan="2">Main Substation Transformer[1]</td><td colspan="2"><u>345/115 kV Transformer:</u>
X = 9.497%, R = 0.237%, Winding MVA = 319.8 MVA, Rating MVA = 533 MVA</td><td rowspan="2"><u>345/34.5 kV Transformer T1:</u>
X = 8.497%, R = 0.212%, Winding MVA = 123 MVA, Rating MVA = 205 MVA</td><td rowspan="2"><u>345/34.5 kV Transformer T2:</u>
X = 8.497%, R = 0.212%, Winding MVA = 123 MVA, Rating MVA = 205 MVA</td></tr>
<tr><td><u>115/34.5 kV Transformer:</u>
X = 9.497%, R = 0.237%, Winding MVA = 120 MVA, Rating MVA = 200 MVA</td><td><u>115/34.5 kV Transformer:</u>
X = 9.497%, R = 0.237%, Winding MVA = 120 MVA, Rating MVA = 200 MVA</td></tr>
<tr><td>Generation Interconnection Line (115 kV)</td><td>Length = 4.14 miles
R = 0.002650 pu
X = 0.020715 pu
B = 0.003480 pu</td><td>Length = 0.57 miles
R = 0.000360 pu
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B = 0.000480 pu</td><td>N/A</td><td>N/A</td></tr>
<tr><td>GSU Transformer[1]</td><td>Gen 1 Equivalent Qty: 77:
X = 6%, R = 0.84%, Rating MVA = 200.2 MVA</td><td>Gen 2 Equivalent Qty: 79
X = 6%, R = 0.84%, Rating MVA = 205.4 MVA</td><td>Gen 1 Equivalent Qty: 80:
X = 5.699%, R = 0.76%, Winding MVA = 192 MVA, Rating MVA = 214.8 MVA</td><td>Gen 2 Equivalent Qty: 79:
X = 5.699%, R = 0.76%, Winding MVA = 189.6 MVA, Rating 212.1 MVA</td></tr>
<tr><td>Equivalent Collector Line[2]</td><td>R = 0.002654 pu
X = 0.002542 pu
B = 0.082000 pu</td><td>R = 0.002341 pu
X = 0.002267 pu
B = 0.075500 pu</td><td>R = 0.002185 pu
X = 0.003353 pu
B = 0.031257 pu</td><td>R = 0.002213 pu
X = 0.003390 pu
B = 0.030983 pu</td></tr>
</table>

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

Table ES-3: GEN-2011-022 Modification Request

Facility	Existing		Modification	
Point of Interconnection	Hitchland 345 kV (523097)		Hitchland 345 kV (523097)	
Configuration/Capacity	130 X Siemens 2.3 MW = 299 MW		133 X Siemens 2.3 MW = 305.9 MW with PPC limiting POI injection to 299 MW	
Generation Interconnection Line	Length = 0.5 miles R = 0.000720 pu X = 0.008020 pu B = 0.133900 pu		**<u>Line shared with GEN-2010-014:</u>** Length = 15 miles R = 0.000735 pu X = 0.007485 pu B = 0.126000 pu	
Main Substation Transformer[1]	X = 9.998%, R = 0.182%, Winding MVA = 102 MVA, Rating MVA = 167 MVA	X = 10%, R = 0.00%, Winding MVA = 100 MVA, Rating MVA = 167 MVA	**<u>Transformer T1:</u>** X = 8.497%, R = 0.212%, Winding MVA = 102 MVA, Rating MVA = 170 MVA	**<u>Transformer T2:</u>** X = 8.497%, R = 0.212%, Winding MVA = 102 MVA, Rating MVA = 170 MVA
GSU Transformer[1]	Gen 1 Equivalent Qty: 65: X = 6%, R = 0.84%, Rating MVA = 169 MVA	Gen 2 Equivalent Qty: 65: X = 6%, R = 0.84%, Rating MVA = 169 MVA	Gen 1 Equivalent Qty: 67: X = 5.699%, R = 0.76%, Winding MVA = 160.8 MVA, Rating MVA = 179.9 MVA	Gen 2 Equivalent Qty: 66: X = 5.699%, R = 0.76%, Winding MVA = 158.4 MVA, Rating MVA = 177.2 MVA
Equivalent Collector Line[2]	R = 0.006400 pu X = 0.009000 pu B = 0.057400 pu	R = 0.009000 pu X = 0.012800 pu B = 0.072200 pu	R = 0.002600 pu X = 0.003995 pu B = 0.026139 pu	R = 0.002629 pu X = 0.004034 pu B = 0.025865 pu

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

SPP determined that power flow should not be performed based on the POI MW injection increase of 1.07% compared to the recently studied DISIS-2017-001 power flow models. However, SPP determined that while the modification used the same turbine manufacturer, Siemens, the project capacity increased and included the use of a PPC which required short circuit and dynamic stability analyses.

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 post-modification GEN-2015-082 DISIS-2016-002 Group 2 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-2010-014 and GEN-2011-022 POI as applicable based on SPP's confirmation of the latest project configurations. 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-2010-014 and GEN-2011-022 project needed a combined 24.9 MVAr of reactor shunts on the 34.5 kV bus of the project substations, a decrease from the 48.4 MVAr found for the existing GEN-2010-014 and GEN-2011-022 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 addressed by the Interconnection Customer and the Transmission Owner and/or Transmission Operator.

The results from the short circuit analysis with the updated topology showed that the maximum GEN-2010-014 and GEN-2011-022 contribution to three-phase fault currents in the immediate systems at or near GEN-2010-014 and GEN-2011-022 was not greater than 1.07 kA for the 2018SP and 2026SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2010-014 and GEN-2011-022 generators online were below 32 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 83 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

The results of the dynamic stability analysis showed that the Finney stuck breaker faults FLT1011-SB (17WP) and FLT1012-SB (18SP and 26SP) resulted in the wind farm Buff Dunes (GEN-2008-018) radially connecting to the Lamar HVDC line. This system configuration is under review by SPP and the TO to determine the mitigation needed. The issue was observed in the existing system prior to the modification request and is not attributed to this Modification Request.

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.

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

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

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

1.0 Scope of Study

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2010-014 and GEN-2011-022. A Modification Request Impact Study is a generation interconnection study performed to evaluate the impacts of modifying the DISIS study assumptions. The determination of the required scope of the study is dependent upon the specific modification requested and how it may impact the results of the DISIS study. Impacting the DISIS results could potentially affect the cost or timing of any Interconnection Request with a later Queue priority date, deeming the requested modification a Material Modification. The criteria sections below include reasoning as to why an analysis was either included or excluded from the scope of study.

All analyses were performed using the PTI PSS/E version 33.7 software. The post-modification GEN-2015-082 DISIS-2016-002 Group 2 models were used as the base models for this study. The results of each analysis are presented in the following sections.

1.1 Power Flow

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

1.2 Stability Analysis, Short Circuit Analysis

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

1.3 Charging Current Compensation Analysis

SPP requires that a charging current compensation analysis be performed on the requested modification configuration as it is a non-synchronous resource. The charging current compensation analysis determines the capacitive effect at the POI caused by the project's collector system and transmission line's capacitance. A shunt reactor size is determined in order to offset the capacitive effect and maintain zero (0) MVAr flow at the POI while the 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-2010-014 and GEN-2011-022 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a point of interconnection (POI) at the Hitchland 345 kV Substation. At the time of the posting of this report, GEN-2010-014 and GEN-2011-022 are active Interconnection Requests with queue statuses of "IA FULLY EXECUTED/ON SCHEDULE." Both GEN-2010-014 and GEN-2011-022 are wind farms, and have maximum summer and winter queue capacities of 358.8 MW and 299 MW respectively with Energy Resource Interconnection Service (ERIS).

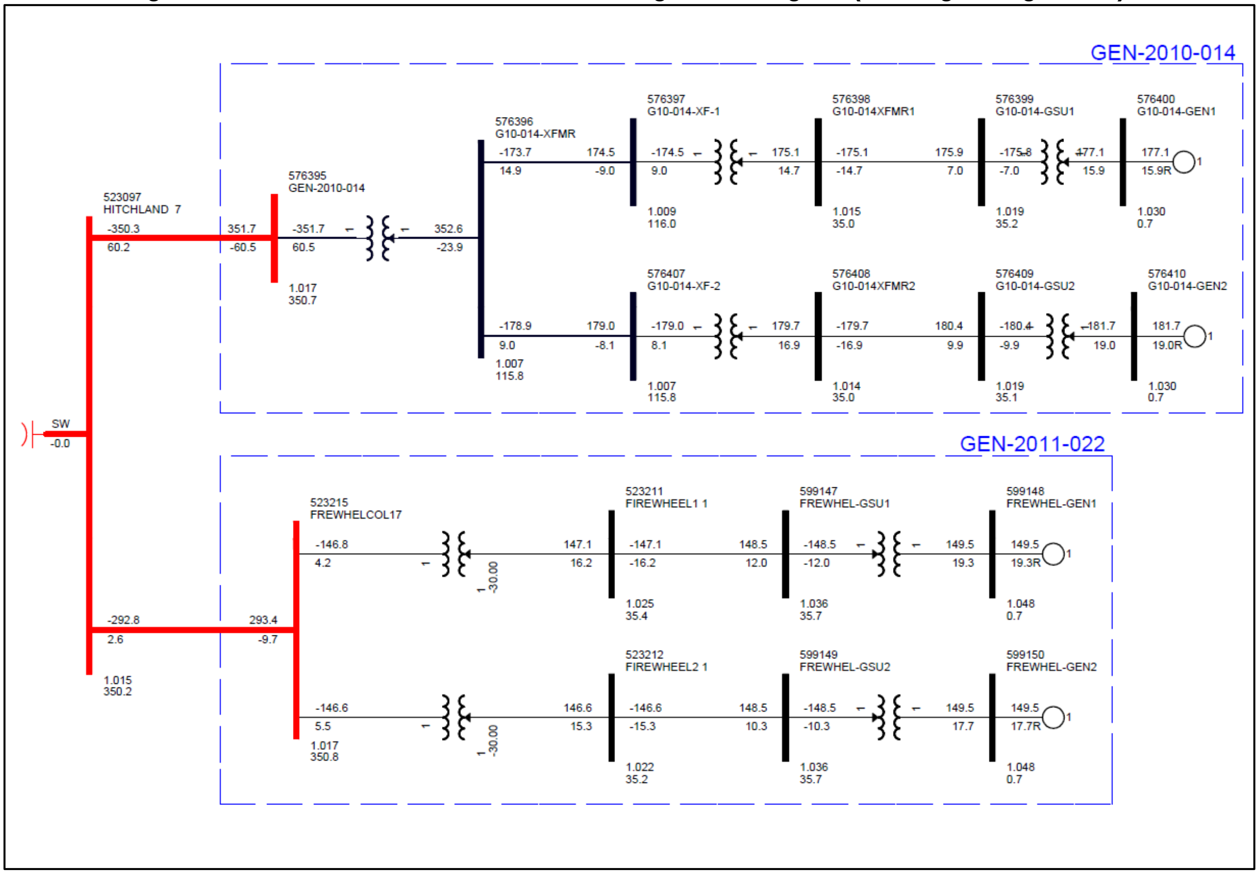
The GEN-2010-014 and GEN-2011-022 projects were originally studied as part of Group 2 in the DISIS-2010-001 and DISIS-2011-001 studies respectively. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2010-014 and GEN-2011-022 configurations.

The GEN-2010-014 and GEN-2011-022 projects are proposed to interconnect in the Southwestern Public Service Company (SWPS) control area with a combined capacity of 657.8 MW as shown in Table 2-1 below.

Table 2-1: GEN-2010-014 & GEN-2011-022 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	Capacity (MW)
GEN-2010-014	Hitchland 345 kV (523097)	156 x Siemens 2.3 MW = 358.8 MW	358.8
GEN-2011-022	Hitchland 345 kV (523097)	130 X Siemens 2.3 MW = 299 MW	299.0
		Total Combined Capacity	657.8

Figure 2-1: GEN-2010-014 & GEN-2011-022 Single Line Diagram (Existing Configuration)



This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2010-014 from the previously studied 156 x Siemens 2.3 MW to a turbine configuration of 159 x Siemens 2.3 MW with a generating capacity of 365.7 MW, and GEN-2011-022 from the previously studied 130 X Siemens 2.3 MW to change the turbine configuration to 133 X Siemens 2.3 MW with a generating capacity of 305.9 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, main substation transformers, and generation interconnection lines. Figure 2-2 shows the power flow model single line diagram for the GEN-2010-014 and GEN-2011-022 modification. The existing and modified configurations for GEN-2010-014 and GEN-2011-022 are shown in Table 2-2 and Table 2-3 respectively.

The modified generating capacities of both GEN-2010-014 and GEN-2011-022 (365.7 MW and 305.9 MW) exceed their respective GIA Interconnection Service amounts, 358.8 MW and 299 MW.

Figure 2-2: GEN-2010-014 & GEN-2011-022 Single Line Diagram (Modification Configuration)

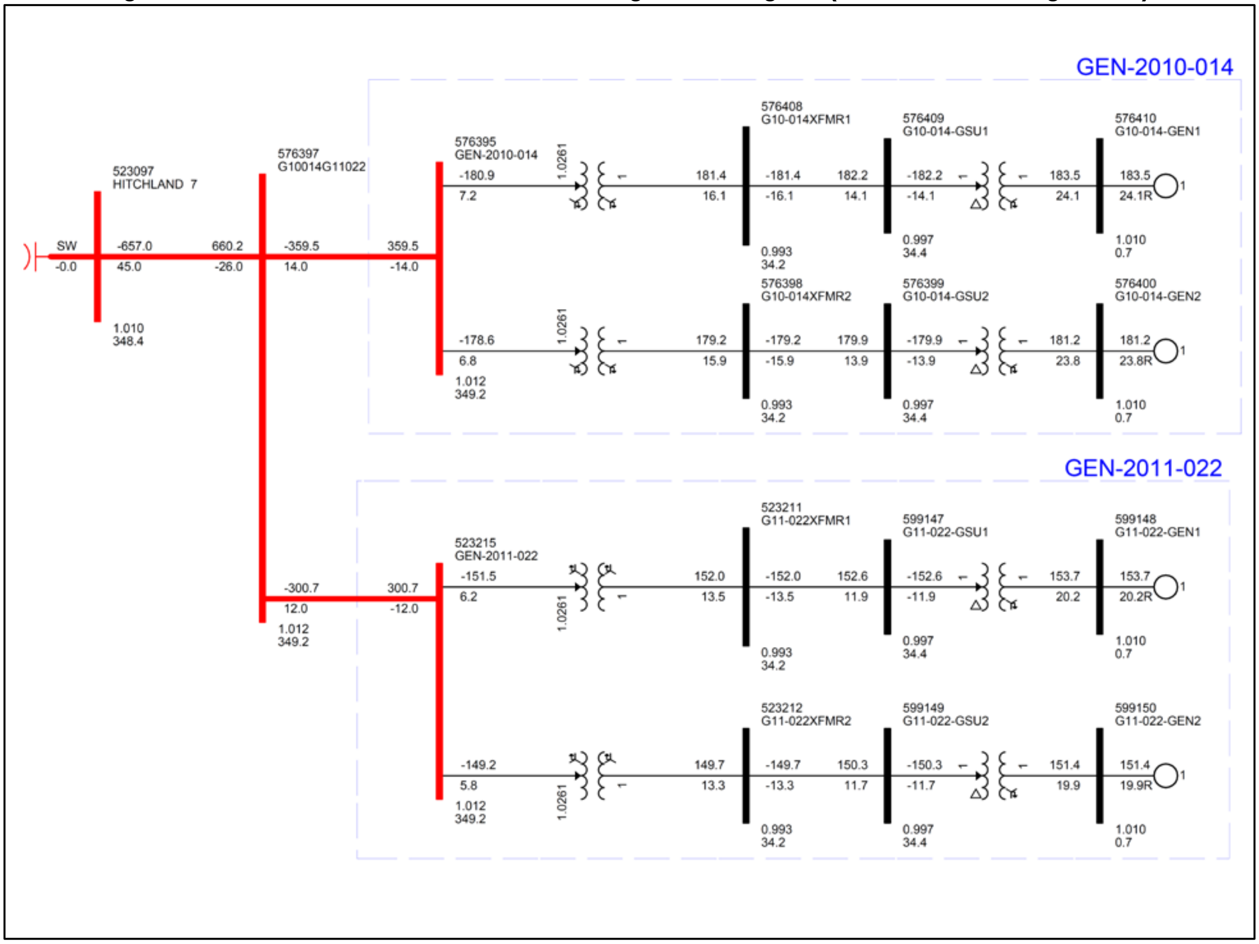


Table 2-2: GEN-2010-014 Modification Request

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<tr><th>Facility</th><th colspan="2">Existing</th><th colspan="2">Modification</th></tr>
<tr><td>Point of Interconnection</td><td colspan="2">Hitchland 345 kV (523097)</td><td colspan="2">Hitchland 345 kV (523097)</td></tr>
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R = 0.000735 pu
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B = 0.126000 pu</td></tr>
<tr><td rowspan="2">Main Substation Transformer[1]</td><td colspan="2"><u>345/115 kV Transformer:</u>
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X = 8.497%, R = 0.212%, Winding MVA = 123 MVA, Rating MVA = 205 MVA</td><td rowspan="2"><u>345/34.5 kV Transformer T2:</u>
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Table 2-3: GEN-2011-022 Modification Request

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<tr><th>Facility</th><th colspan="2">Existing</th><th colspan="2">Modification</th></tr>
<tr><td>Point of Interconnection</td><td colspan="2">Hitchland 345 kV (523097)</td><td colspan="2">Hitchland 345 kV (523097)</td></tr>
<tr><td>Configuration/Capacity</td><td colspan="2">130 X Siemens 2.3 MW = 299 MW</td><td colspan="2">133 X Siemens 2.3 MW = 305.9 MW with PPC limiting POI injection to 299 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td colspan="2">Length = 0.5 miles
R = 0.000720 pu
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B = 0.133900 pu</td><td colspan="2"><u>Line shared with GEN-2010-014</u>:
Length = 15 miles
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<tr><td>Main Substation Transformer[1]</td><td>X = 9.998%, R = 0.182%, Winding MVA = 102 MVA, Rating MVA = 167 MVA</td><td>X = 10%, R = 0.00%, Winding MVA = 100 MVA, Rating MVA = 167 MVA</td><td><u>Transformer T1:</u>
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X = 0.004034 pu
B = 0.025865 pu</td></tr>
</table>

1) X/R based on Winding MVA, 2) all pu 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 post-modification GEN-2015-082 DISIS-2016-002 Group 2 study models. Aneden updated the GIRs that had POIs within 3 buses of the GEN-2010-014 and GEN-2011-022 POI as applicable based on SPP's confirmation of the latest project configurations.

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-2010-014 and GEN-2011-022. 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 1.07%) 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-2010-014 & GEN-2011-022 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-2010-014 & GEN-2011-022	650.1	657.0	1.07%

3.2 Turbine Parameters Comparison

SPP determined that while the modification used the same turbine manufacturer, Siemens, 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-2010-014 & GEN-2011-022 to determine the capacitive charging effects during reduced generation conditions (unsuitable wind speeds, unsuitable solar irradiance, insufficient state of charge, idle conditions, curtailment, etc.) at the generation site and to size shunt reactors that would reduce the project reactive power contribution to the POI to approximately zero.

4.1 Methodology and Criteria

The GEN-2010-014 and GEN-2011-022 generators were switched out of service while other collection system elements remained in-service. A shunt reactor was tested at each 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-2010-014 and GEN-2011-022 projects needed approximately 24.9 MVAr of compensation at its project substations, to reduce the POI MVAr to zero. This is a decrease from the combined 48.4 MVAr found for the existing GEN-2010-014 and GEN-2011-022 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-2010-014 and GEN-2011-022 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 addressed by the Interconnection Customer and 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-2010-014	523097	Hitchland 345 kV	19.69	19.69	19.69
GEN-2011-022	523097	Hitchland 345 kV	5.21	5.21	5.21
Total			24.9	24.9	24.9

Figure 4-1: GEN-2010-014 & GEN-2011-022 Single Line Diagram (Existing Shunt Reactor)

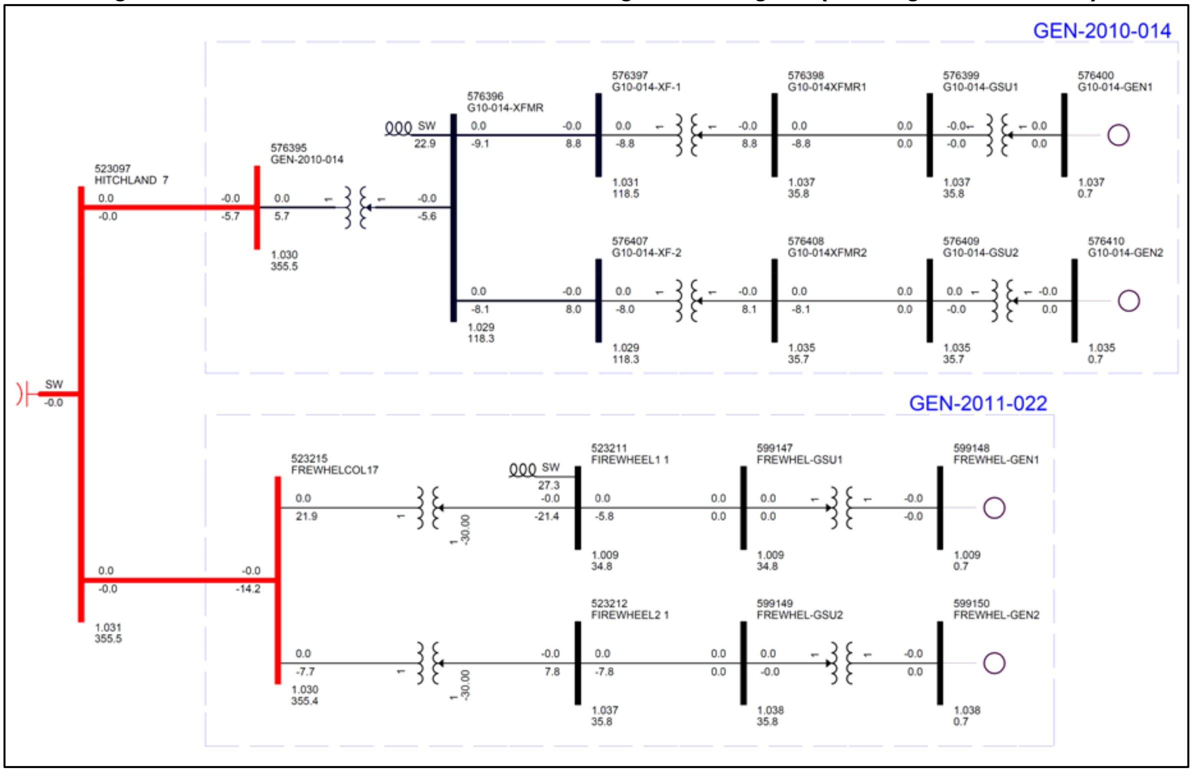
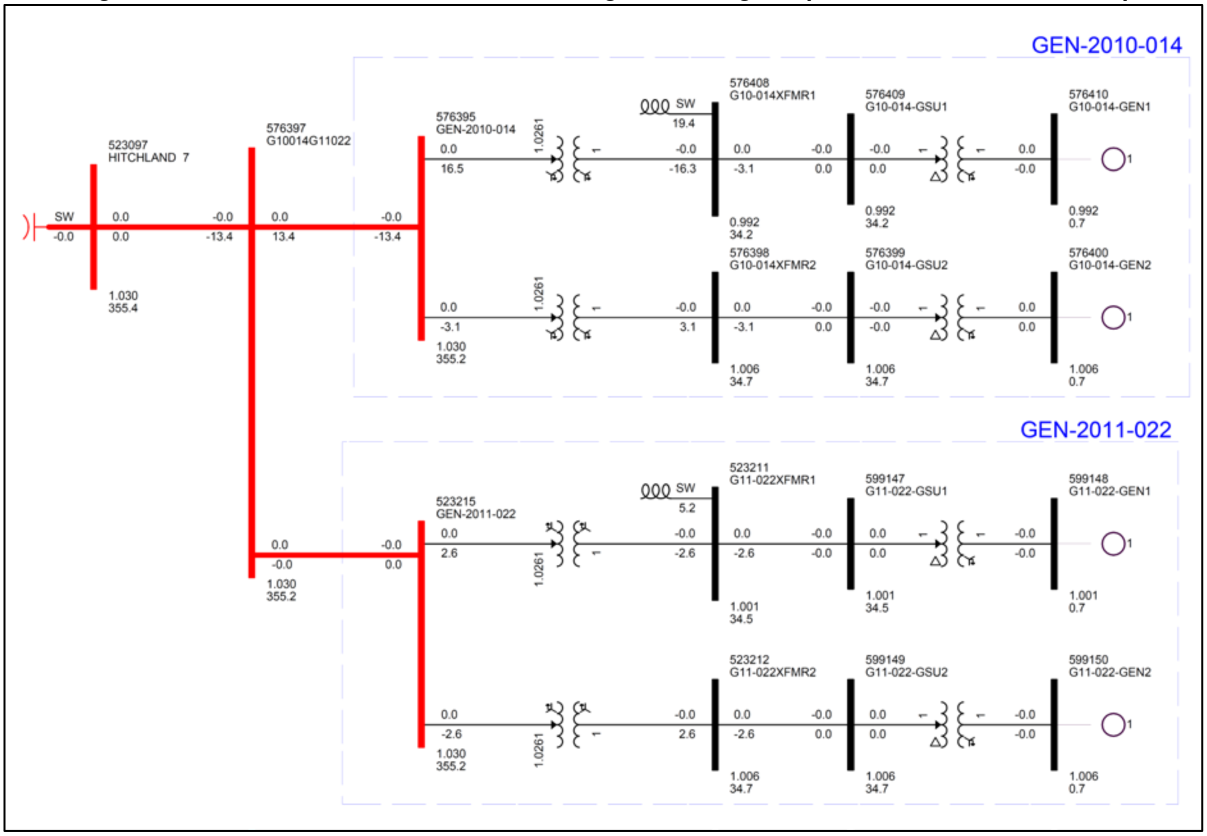


Figure 4-2: GEN-2010-014 & GEN-2011-022 Single Line Diagram (Modification Shunt Reactor)



5.0 Short Circuit Analysis

A short circuit study was performed using the 2018SP and 2026SP models for GEN-2010-014 and GEN-2011-022. The detailed results of the short circuit analysis are provided in Appendix B.

5.1 Methodology

The short circuit analysis included applying a 3-phase fault on buses up to 5 levels away from the 345 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels with and without GEN-2010-014 and GEN-2011-022 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-2010-014 and GEN-2011-022 POI bus fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 14.56 kA.

The maximum fault current calculated within 5 buses of the GEN-2010-014 and GEN-2011-022 POI was less than 32 kA for the 2018SP and 2026SP models respectively. The maximum GEN-2010-014 and GEN-2011-022 contribution to three-phase fault current was about 7.9% and 1.07 kA.

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
2018SP	13.36	14.41	1.06	7.9%
2026SP	13.50	14.56	1.07	7.9%

Table 5-2: 2018SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	8.6	0.00	0.0%
115	30.9	0.19	1.0%
230	27.1	0.50	3.6%
345	18.6	1.06	7.9%
Max	**30.9**	**1.06**	**7.9%**

Table 5-3: 2026SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	8.7	0.01	0.5%
115	31.3	0.30	1.6%
230	27.4	0.49	3.5%
345	18.7	1.07	7.9%
Max	**31.3**	**1.07**	**7.9%**

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-2010-014 and GEN-2011-022 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-2010-014 configuration of 159 x Siemens 2.3 MW (SWTGU2) and GEN-2011-022 configuration of 133 X Siemens 2.3 MW (SWTGU2). The requested modification included the use of a PPC (GWFVC) 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 post-modification GEN-2015-082 DISIS-2016-002 Group 2 models. The modifications requested for the GEN-2010-014 and GEN-2011-022 projects were used to create modified stability models for this impact study. In addition, the following system adjustment was made to address existing base case issues:

1. Noble wind farm MPT tap ratio was adjusted to 1.05 in the 18SP case

The modified dynamics model data for the Group 2 requests, GEN-2010-014 and GEN-2011-022, 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-2010-014 and GEN-2011-022 and other equally and prior queued projects in Group 2. In addition, voltages of five (5) buses away from the POI of GEN-2010-014 and GEN-2011-022 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within this study area including 520 (AEPW), 524 (OKGE), 525 (WFEC), 526 (SPS), 531 (MIDW), 534 (SUNC), 536 (WERE) 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-2010-014 and GEN-2011-022 and selected additional fault events for GEN-2010-014 and GEN-2011-022 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
FLT02-3PH	P1	3 phase fault on the BADGER 7 (515677) to Beaver County (515554) 345kV line CKT 1, near BADGER 7. a. Apply fault at the BADGER 7 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT07-3PH	P1	3 phase fault on the Beaver County (515554) to G14-037-TAP (560010) 345kV line CKT 1, near Beaver County. a. Apply fault at the Beaver County 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT08-3PH	P1	3 phase fault on the HITCHLAND (523097) to G14-037-TAP (560010) 345kV line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT12-3PH (17WP)	P1	3 phase fault on the HITCHLAND (523097) to FINNEY 345kV (523853) line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip 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 HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1, near HITCHLAND 345kV. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT14-3PH	P1	3 phase fault on the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip 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 HITCHLAND (523095) to Moore County 230kV (523309) line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 230kV bus. b. Clear fault after 5 cycles and trip 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.
FLT16-3PH	P1	3 phase fault on the HITCHLAND 230kV (523095) to HITCHLAND 115kV (523093) HITCHLAND 13.2kV (523092) XFMR CKT 1, near HITCHLAND 230kV. a. Apply fault at the HITCHLAND 230kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT40-3PH	P1	3 phase fault on the BADGER 7 (515677) to Beaver County (515554) 345kV line CKT 2, near BADGER 7. a. Apply fault at the BADGER 7 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT40-PO1	P6	**PRIOR OUTAGE of BADGER 7 (515677) to Beaver County (515554) 345kV line CKT 1;** 3 phase fault on the BADGER 7 (515677) to Beaver County (515554) 345kV line CKT 2, near BADGER 7. a. Apply fault at the BADGER 7 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT07-PO2	P6	**PRIOR OUTAGE of Beaver County (515554) to G14-037-TAP (560010) kV line CKT 2;** 3 phase fault on the Beaver County (515554) to G14-037-TAP (560010) 345kV line CKT 1, near Beaver County. a. Apply fault at the Beaver County 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT08-PO3	P6	**PRIOR OUTAGE of HITCHLAND (523097) to G14-037-TAP (560010) 345kV line CKT 2;** 3 phase fault on the HITCHLAND (523097) to G14-037-TAP (560010) 345kV line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9001-3PH	P1	3 phase fault on the HITCHLAND (523097) to NOVUS1 (523112) 345kV line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. **Trip Generators G06-044GEN1A (579373), G06-044GEN2A (579376), G06-044GEN2B (579380) and NOVUS_WND (523107).** 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 HITCHLAND (523097) to NOBLE_WND 7 (523101) 345kV line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. **Trip Generators NBI_WND_WTG11 (523121), NBI_WND_WTG21 (523122), and NBLWND-WTG31 (523123).** 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.
FLT9003-3PH (18SP and 26SP)	P1	3 phase fault on the HITCHLAND (523097) to WALKEMETER 7 345kV (523823) CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip 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.
FLT9004-3PH (18SP and 26SP)	P1	3 phase fault on the WALKEMETER 7 (523823) to FINNEY 345kV (523853) line CKT 1, near WALKEMETER 7. a. Apply fault at the WALKEMETER 7 345kV bus. b. Clear fault after 5 cycles and trip 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 FINNEY (523853) to BUFF_DUNES 7 345kV (523118) line CKT 1, near FINNEY. a. Apply fault at the FINNEY 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip Generator G08-018-GEN1 (579403).** 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.
FLT9006-3PH	P1	3 phase fault on the FINNEY (523853) to LAMAR7 345kV (599950) line CKT 1, near FINNEY. a. Apply fault at the FINNEY 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip Generator LAMAR (599951).** 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 FINNEY (523853) to HOLOCOMB 345kV (531449) line CKT 1, near FINNEY. a. Apply fault at the FINNEY 345kV bus. b. Clear fault after 5 cycles and trip 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 BUFF_DUNES 345kV (523118) to 34.5kV (523116) to 13.2kV (523115) XFMR CKT 2, near BUFF_DUNES 345kV. a. Apply fault at the BUFF_DUNES 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer. **Trip Generator G08-018-GEN1 (579403).**

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9009-3PH	P1	3 phase fault on the HOLOCOMB 345kV (531449) to 115kV (531448) to 13.2kV (531450) XFMR CKT 1, near HOLOCOMB 345kV. a. Apply fault at the HOLOCOMB 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9010-3PH	P1	3 phase fault on the HOLOCOMB (531449) to SETAB (531465) 345kV line CKT 1, near HOLOCOMB. a. Apply fault at the HOLOCOMB 345kV bus. b. Clear fault after 5 cycles and trip 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 HOLOCOMB (531449) to BUCKNER7 (531501) 345kV line CKT 1, near HOLOCOMB. a. Apply fault at the HOLOCOMB 345kV bus. b. Clear fault after 5 cycles and trip 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 POTTER_CO 345kV (523961) to 230kV (523959) to 13.2kV (523957) XFMR CKT 1, near POTTER_CO 345kV. a. Apply fault at the POTTER_CO 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9013-3PH	P1	3 phase fault on the POTTER_CO 345kV (523961) to SPNSPUR_WND7 (524296) 345kV line CKT 1, near POTTER_CO. a. Apply fault at the POTTER_CO 345kV bus. b. Clear fault after 5 cycles and trip the faulted line. **Trip Generator G08-051-GEN2 (579413) and SPNSPUR_WND (599106).** 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.
FLT9014-3PH	P1	3 phase fault on the G14-037-TAP (560010) to Beaver County (515554) 345kV line CKT 1, near G14-037-TAP. a. Apply fault at the G14-037-TAP 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT9015-3PH	P1	3 phase fault on the Beaver County (515554) to GEN-2013-030 (583760) 345kV line CKT 1, near Beaver County. a. Apply fault at the Beaver County 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. **Trip Generator G13-030-GEN1 (583763) and G13-030-GEN2 (583766).** 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.
FLT9016-3PH	P1	3 phase fault on the Beaver County (515554) to PALDR2W7 (515590) 345kV line CKT 1, near Beaver County. a. Apply fault at the Beaver County 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. **Trip Generator G08-047-GEN1 (573506) and G08-047-GEN2 (573510) .** 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 Beaver County (515554) to BALKOW 7 (515618) 345kV line CKT 1, near Beaver County. a. Apply fault at the Beaver County 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. **Trip Generator BALKOWG1 (515658) and BALKOWG1 (515659) .** 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 Beaver County (515554) to BADGER 7 (515677) 345kV line CKT 1, near Beaver County. a. Apply fault at the Beaver County 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9019-3PH	P1	3 phase fault on the Moore County (523309) to POTTER_CO (523959) 230kV line CKT 1, near Moore County. a. Apply fault at the Moore County 230kV bus. b. Clear fault after 5 cycles and trip 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 POTTER_CO (523959) to HARRNG_EST 6 (523979) 230kV line CKT 1, near POTTER_CO. a. Apply fault at the POTTER_CO 230kV bus. b. Clear fault after 5 cycles and trip 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 POTTER_CO (523959) to BUSHLAND 6 (524267) 230kV line CKT 1, near POTTER_CO. a. Apply fault at the POTTER_CO 230kV bus. b. Clear fault after 5 cycles and trip 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 POTTER_CO (523959) to ROLLHILLS 6 (524010) 230kV line CKT 1, near POTTER_CO. a. Apply fault at the POTTER_CO 230kV bus. b. Clear fault after 5 cycles and trip 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 POTTER_CO (523959) to NEWHART 6 (525461) 230kV line CKT 1, near POTTER_CO. a. Apply fault at the POTTER_CO 230kV bus. b. Clear fault after 5 cycles and trip 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 POTTER_CO (523959) to CHAN+TASCOS6 (523869) 230kV line CKT 1, near POTTER_CO. a. Apply fault at the POTTER_CO 230kV bus. b. Clear fault after 5 cycles and trip 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.
FLT9025-3PH	P1	3 phase fault on the HITCHLAND (523095) to OCHILTREE 6 230kV (523155) line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 230kV bus. b. Clear fault after 5 cycles and trip 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.
FLT9014-PO3	P6	**PRIOR OUTAGE of HITCHLAND (523097) to G14-037-TAP (560010) 345kV line CKT 2;** 3 phase fault on the G14-037-TAP (560010) to Beaver County (515554) 345kV line CKT 1, near G14-037-TAP. a. Apply fault at the G14-037-TAP 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT08-PO4	P6	**PRIOR OUTAGE of the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1;** 3 phase fault on the HITCHLAND (523097) to G14-037-TAP (560010) 345kV line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT12-PO4 (17WP)	P6	**PRIOR OUTAGE of the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1;** 3 phase fault on the HITCHLAND (523097) to FINNEY 345kV (523853) line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip 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-PO4	P6	**PRIOR OUTAGE of the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1;** 3 phase fault on the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1, near HITCHLAND 345kV. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9003-PO4 (18SP and 26SP)	P6	**PRIOR OUTAGE of the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1;** 3 phase fault on the HITCHLAND (523097) to WALKEMETER 7 345kV (523823) CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip 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.
FLT08-PO5	P6	**PRIOR OUTAGE of the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2;** 3 phase fault on the HITCHLAND (523097) to G14-037-TAP (560010) 345kV line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT12-PO5 (17WP)	P6	**PRIOR OUTAGE of the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2;** 3 phase fault on the HITCHLAND (523097) to FINNEY 345kV (523853) line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip 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-PO5	P6	**PRIOR OUTAGE of the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2;** 3 phase fault on the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1, near HITCHLAND 345kV. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT14-PO5	P6	**PRIOR OUTAGE of the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2;** 3 phase fault on the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip 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.
FLT9003-PO5 (18SP and 26SP)	P6	**PRIOR OUTAGE of the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2;** 3 phase fault on the HITCHLAND (523097) to WALKEMETER 7 345kV (523823) CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip 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
FLT08-PO6 (17WP)	P6	**PRIOR OUTAGE of the HITCHLAND (523097) to FINNEY (523853) 345kV line CKT 1;** 3 phase fault on the HITCHLAND (523097) to G14-037-TAP (560010) 345kV line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT13-PO6 (17WP)	P6	**PRIOR OUTAGE of the HITCHLAND (523097) to FINNEY (523853) 345kV line CKT 1;** 3 phase fault on the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1, near HITCHLAND 345kV. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT14-PO6 (17WP)	P6	**PRIOR OUTAGE of the HITCHLAND (523097) to FINNEY (523853) 345kV line CKT 1;** 3 phase fault on the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip 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.
FLT08-PO7 (18SP and 26SP)	P6	**PRIOR OUTAGE of the HITCHLAND (523097) to WALKEMETER 7 (523823) 345kV line CKT 1;** 3 phase fault on the HITCHLAND (523097) to G14-037-TAP (560010) 345kV line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT13-PO7 (18SP and 26SP)	P6	**PRIOR OUTAGE of the HITCHLAND (523097) to WALKEMETER 7 (523823) 345kV line CKT 1;** 3 phase fault on the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1, near HITCHLAND 345kV. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT14-PO7 (18SP and 26SP)	P6	**PRIOR OUTAGE of the HITCHLAND (523097) to WALKEMETER 7 (523823) 345kV line CKT 1;** 3 phase fault on the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1, near HITCHLAND. a. Apply fault at the HITCHLAND 345kV bus. b. Clear fault after 5 cycles and trip 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 POTTER_CO 7 (523961) at 345kV bus** a. Apply single-phase fault at POTTER_CO 7 (523961) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the Bus POTTER_CO 7 (523961). **Trip generator BALKOWG1 (579413)** **Trip generator BALKOWG2 (599106)**
FLT1002-SB (18SP and 26SP)	P4	**Stuck Breaker on at WALKEMEYER 7 (523823) at 345kV bus** a. Apply single-phase fault at WALKEMEYER 7 (523823) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the Bus WALKEMEYER 7 (523823).
FLT1003-SB	P4	**Stuck Breaker on at Beaver County (515554) at 345kV bus** a. Apply single-phase fault at Beaver County (515554) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the Beaver County (515554) to BADGER (515677) 345 kV line CKT 2. d. Trip the Beaver County (515554) to BALKOW (515618) 345 kV line CKT 1. **Trip generator BALKOWG1 (515658)** **Trip generator BALKOWG2 (515659)**

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT1004-SB	P4	**Stuck Breaker on at Beaver County (515554) at 345kV bus** a. Apply single-phase fault at Beaver County (515554) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the Beaver County (515554) to PALDR2W7 (515590) 345 kV line CKT 1. d. Trip the Beaver County (515554) to G14-037-TAP (560010) 345 kV line CKT 1. **Trip generator G08-047-GEN1 (573506)** **Trip generator G08-047-GEN2 (573510)**
FLT1005-SB	P4	**Stuck Breaker on at Beaver County (515554) at 345kV bus** a. Apply single-phase fault at Beaver County (515554) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the Beaver County (515554) to G14-037-TAP (560010) 345 kV line CKT 1. d. Trip the Beaver County (515554) to G14-037-TAP (560010) 345 kV line CKT 2.
FLT1006-SB	P4	**Stuck Breaker on at Beaver County (515554) at 345kV bus** a. Apply single-phase fault at Beaver County (515554) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the Beaver County (515554) to BADGER (515677) 345 kV line CKT 2. d. Trip the Beaver County (515554) to BADGER (515677) 345 kV line CKT 1.
FLT1007-SB	P4	**Stuck Breaker on at Beaver County (515554) at 345kV bus** a. Apply single-phase fault at Beaver County (515554) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the Beaver County (515554) to G14-037-TAP (560010) 345 kV line CKT 2. d. Trip the Beaver County (515554) to BALKOW (515618) 345 kV line CKT 1. **Trip generator BALKOWG1 (515658)** **Trip generator BALKOWG2 (515659)**
FLT1008-SB	P4	**Stuck Breaker on at Beaver County (515554) at 345kV bus** a. Apply single-phase fault at Beaver County (515554) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the Beaver County (515554) to PALDR2W7 (515590) 345 kV line CKT 1. d. Trip the Beaver County (515554) to BADGER (515677) 345 kV line CKT 1. **Trip generator G08-047-GEN1 (573506)** **Trip generator G08-047-GEN2 (573510)**
FLT1009-SB	P4	**Stuck Breaker on at FINNEY (523853) at 345kV bus** a. Apply single-phase fault at FINNEY (523853) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the FINNEY (523853) to BUFF_DUNES 7 (523118) 345kV line CKT 1. d. Trip the FINNEY (523853) to LAMAR7 (599950) 345kV line CKT 1. **Trip Generator G08-018-GEN1 (579403).** **Trip Generator LAMAR (599951).**
FLT1010-SB	P4	**Stuck Breaker on at FINNEY (523853) at 345kV bus** a. Apply single-phase fault at FINNEY (523853) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the FINNEY (523853) to HOLCOMB7 (531449) 345kV line CKT 1. d. Trip the FINNEY (523853) to LAMAR7 (599950) 345kV line CKT 1. **Trip Generator LAMAR (599951).**
FLT1011-SB (17WP)	P4	**Stuck Breaker on at FINNEY (523853) at 345kV bus** a. Apply single-phase fault at FINNEY (523853) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the FINNEY (523853) to HOLOCOMB (531449) 345kV line CKT 1. d. Trip the FINNEY (523853) to HITCHLAND (523097) 345kV line CKT 1.
FLT1012-SB (18SP and 26SP)	P4	**Stuck Breaker on at FINNEY (523853) at 345kV bus** a. Apply single-phase fault at FINNEY (523853) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the FINNEY (523853) to HOLOCOMB (531449) 345kV line CKT 1. d. Trip the FINNEY (523853) to WALKEMETER 7 (523823) 345kV line CKT 1.
FLT1013-SB (17WP)	P4	**Stuck Breaker on at FINNEY (523853) at 345kV bus** a. Apply single-phase fault at FINNEY (523853) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the FINNEY (523853) to BUFF_DUNES 7 (523118) 345kV line CKT 1. d. Trip the FINNEY (523853) to HITCHLAND (523097) 345kV line CKT 1. **Trip Generator G08-018-GEN1 (579403).**

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT1014-SB (18SP and 26SP)	P4	Stuck Breaker on at FINNEY (523853) at 345kV bus a. Apply single-phase fault at FINNEY (523853) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the FINNEY (523853) to BUFF_DUNES 7 (523118) 345kV line CKT 1. d. Trip the FINNEY (523853) to WALKEMETER 7 (523823) 345kV line CKT 1. **Trip Generator G08-018-GEN1 (579403).**
FLT1015-SB	P4	Stuck Breaker on at HITCHLAND 6 (523095) at 230kV bus a. Apply single-phase fault at HITCHLAND 6 (523095) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 230kV (523095) to HITCHLAND 115kV (523093) HITCHLAND 13.2kV (523092) XFMR CKT 1. d. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1.
FLT1016-SB	P4	Stuck Breaker on at HITCHLAND 6 (523095) at 230kV bus a. Apply single-phase fault at HITCHLAND 6 (523095) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 230kV (523095) to HITCHLAND 115kV (523093) HITCHLAND 13.2kV (523098) XFMR CKT 2. d. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2.
FLT1017-SB	P4	Stuck Breaker on at HITCHLAND 6 (523095) at 230kV bus a. Apply single-phase fault at HITCHLAND 6 (523095) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 230kV (523095) to HITCHLAND 115kV (523093) HITCHLAND 13.2kV (523092) XFMR CKT 1. d. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1. e. Trip the HITCHLAND (523095) to Moore County 230kV (523309) line CKT 1.
FLT1018-SB	P4	Stuck Breaker on at HITCHLAND 6 (523095) at 230kV bus a. Apply single-phase fault at HITCHLAND 6 (523095) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 230kV (523095) to HITCHLAND 115kV (523093) HITCHLAND 13.2kV (523098) XFMR CKT 2. d. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2. e. Trip the HITCHLAND (523095) to Moore County 230kV (523309) line CKT 1.
FLT1019-SB	P4	Stuck Breaker on at HITCHLAND 6 (523095) at 230kV bus a. Apply single-phase fault at HITCHLAND 6 (523095) on the 230kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 230kV (523095) to HITCHLAND 115kV (523093) HITCHLAND 13.2kV (523098) XFMR CKT 2. d. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2. e. Trip the HITCHLAND (523095) to OCHILTREE 6 230kV (523155) line CKT 1.
FLT1020-SB	P4	Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2. d. Trip the HITCHLAND (523097) to NOBLE_WND 7 (523101) 345kV line CKT 1. **Trip Generators NBI_WND_WTG11 (523121), NBI_WND_WTG21 (523122) and NBLWND-WTG31 (523123).**
FLT1021-SB	P4	**Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus** a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1. d. Trip the HITCHLAND (523097) to NOVUS1 (523112) 345kV line CKT 1. **Trip Generators G06-044GEN1A (579373), G06-044GEN2A (579376), G06-044GEN2B (579380) and NOVUS_WND (523107).**
FLT1022-SB	P4	Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND (523097) to G14-037-TAP (560010) 345kV line CKT 1. d. Trip the HITCHLAND (523097) to NOVUS1 (523112) 345kV line CKT 1.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT1023-SB	P4	Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2. d. Trip the HITCHLAND (523097) to G14-037-TAP (560010) 345kV line CKT 1.
FLT1024-SB	P4	Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2. d. Trip the HITCHLAND (523097) to G14-037-TAP (560010) 345kV line CKT 2.
FLT1025-SB	P4	Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1. d. Trip the HITCHLAND (523097) to NOBLE_WND 7 (523101) 345kV line CKT 1. **Trip Generator G08-051-GEN2 (579413) and SPNSPUR_WND (599106).** **Trip Generators NBI_WND_WTG11 (523121) and NBI_WND_WTG21 (523122).**
FLT1026-SB	P4	**Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus** a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1. d. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1. **Trip Generator G08-051-GEN2 (579413) and SPNSPUR_WND (599106).**
FLT1027-SB (17WP)	P4	**Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus** a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1. d. Trip the HITCHLAND (523097) to FINNEY (523853) 345kV line CKT 1.
FLT1028-SB (18SP and 26SP)	P4	**Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus** a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1. d. Trip the HITCHLAND 345kV (523097) to WALKEMETER 7 (523823) 345kV line CKT 1.
FLT1029-SB (17WP)	P4	**Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus** a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2. d. Trip the HITCHLAND (523097) to FINNEY (523853) 345kV line CKT 1.
FLT1030-SB (18SP and 26SP)	P4	**Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus** a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2. d. Trip the HITCHLAND 345kV (523097) to WALKEMETER 7 (523823) 345kV line CKT 1.

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-2010-014 & GEN-2011-022 Dynamic Stability Results

Fault ID	17WP			18SP			26SP		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable
FLT02-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT08-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT12-3PH	Pass	Pass	Stable						
FLT13-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT14-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT15-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT16-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT40-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH				Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH				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
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB				Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
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

Table 6-2 continued

Fault ID	17WP			18SP			26SP		
	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable	Voltage Recovery	Voltage Violation	Stable
FLT1011-SB**	Pass	Pass	Stable						
FLT1012-SB**				Pass	Pass	Stable	Pass	Pass	Stable
FLT1013-SB	Pass	Pass	Stable						
FLT1014-SB				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
FLT1021-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1022-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1023-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1024-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1025-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1026-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1027-SB	Pass	Pass	Stable						
FLT1028-SB				Pass	Pass	Stable	Pass	Pass	Stable
FLT1029-SB	Pass	Pass	Stable						
FLT1030-SB				Pass	Pass	Stable	Pass	Pass	Stable
FLT40-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT07-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT08-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT08-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT12-PO4	Pass	Pass	Stable						
FLT13-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO4				Pass	Pass	Stable	Pass	Pass	Stable
FLT08-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT12-PO5	Pass	Pass	Stable						
FLT13-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT14-PO5	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO5				Pass	Pass	Stable	Pass	Pass	Stable
FLT08-PO6	Pass	Pass	Stable						
FLT13-PO6	Pass	Pass	Stable						
FLT14-PO6	Pass	Pass	Stable						
FLT08-PO7				Pass	Pass	Stable	Pass	Pass	Stable
FLT13-PO7				Pass	Pass	Stable	Pass	Pass	Stable
FLT14-PO7				Pass	Pass	Stable	Pass	Pass	Stable*

***RELAY SLNOS1 # 1 CIRCUIT 1 FROM 523106 [TXPHSF 3115.00] TO 539672 [E-LIBER3 115.00] tripped**
****Finney faults FLT1011-SB and FLT1012-SB leave a wind farm (Buff Dunes) radially connected to an HVDC line**

After the prior outage loss of the Hitchland to Finney 345 kV line, the following system adjustments were made to support the voltage in the 17WP case:

1. Novus wind farm MPT tap ratio was adjusted to 1.05

2. GEN-2010-014 & GEN-2011-022 GSU tap ratios were adjusted to 1.05
3. GEN-2010-014 & GEN-2011-022 Voltage Schedules were adjusted to 1.03

After the prior outage loss of the Hitchland to Walkemeter 345 kV line, a fault on the Hitchland to Potter County 345kV line caused the Texas County to East Liberal 115 kV Circuit 1 line to trip due to the SLNOS1 #1 relay in the 26SP case. The mitigation identified for this issue included the following system adjustment:

1. Turn off the East Liberal 115 kV capbank (21.7 MVAR)

The Finney stuck breaker faults FLT1011-SB (17WP) and FLT1012-SB (18SP and 26SP) resulted in the wind farm Buff Dunes (GEN-2008-018) radially connecting to the Lamar HVDC line. This system configuration is under review by SPP and the TO to determine the mitigation needed. The issue was observed in the existing system prior to the modification request and is not attributed to this Modification Request.

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 capacities of both GEN-2010-014 and GEN-2011-022 (365.7 MW and 305.9 MW) exceed their respective GIA Interconnection Service amounts, 358.8 MW and 299 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-2010-014 and GEN-2011-022 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-2010-014 and GEN-2011-022 requested a Modification Request Impact Study to assess the impact of the turbine and facility change to a GEN-2010-014 configuration of 159 x Siemens 2.3 MW with a generating capacity of 365.7 MW, and GEN-2011-022 configuration of 133 X Siemens 2.3 MW with a generating capacity of 305.9 MW. The generating capacities for both GEN-2010-014 and GEN-2011-022 (365.7 MW and 305.9 MW) exceed their respective Generator Interconnection Agreement (GIA) Interconnection Service amounts, 358.8 MW and 299 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.

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

SPP determined that power flow should not be performed based on the POI MW injection increase of 1.07% compared to the recently studied DISIS-2017-001 power flow models. However, SPP determined that while the modification used the same turbine manufacturer, Siemens, the project capacity increased and included the use of a PPC which required short circuit and dynamic stability analyses.

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-2010-014 and GEN-2011-022 project needed a combined 24.9 MVAr of reactor shunts on the 34.5 kV bus of the project substations, a decrease from the 48.4 MVAr found for the existing GEN-2010-014 and GEN-2011-022 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 and/or Transmission Operator. The applicable reactive power requirements will be addressed by the Interconnection Customer and the Transmission Owner and/or Transmission Operator.

The results from the short circuit analysis with the updated topology showed that the maximum GEN-2010-014 and GEN-2011-022 contribution to three-phase fault currents in the immediate systems at or near GEN-2010-014 and GEN-2011-022 was not greater than 1.07 kA for the 2018SP and 2026SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2010-014 and GEN-2011-022 generators online were below 32 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 83 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

The results of the dynamic stability analysis showed that the Finney stuck breaker faults FLT1011-SB (17WP) and FLT1012-SB (18SP and 26SP) resulted in the wind farm Buff Dunes (GEN-2008-018) radially connecting to the Lamar HVDC line. This system configuration is under review by SPP and the TO to determine the mitigation needed. The issue was observed in the existing system prior to the modification request and is not attributed to this Modification Request.

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.

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.