
**Submitted to**

**Southwest Power Pool**

SPP Southwest Power Pool

Report On

# GEN-2002-008
# Modification Request Impact Study

Revision R1

Date of Submittal
October 28, 2021

**anedenconsulting.com**

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# Revision History

| DATE OR VERSION NUMBER | AUTHOR | CHANGE DESCRIPTION |
|---|---|---|
| 10/28/2021 | 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-2002-008, an active Generation Interconnection Request (GIR) with a point of interconnection (POI) at the Hitchland 345 kV Substation.

The GEN-2002-008 project is proposed to interconnect in the Southwestern Public Service Company (SWPS) control area with a capacity of 240 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2002-008 to change the turbine configuration to 76 x GE 1.5 MW (wind) + 38 x Power Electronics FP4390K 4.389 MW (battery) for a total generating capacity of 280.782 MW. The generating capacity for GEN-2002-008 (280.782 MW) exceeds the total Generator Interconnection Agreement (GIA) Interconnection Service amount, 240 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 battery generator output to 126 MW and to limit the total power injected into the POI to 240 MW.

In addition, the modification request included changes to the collection system, generator step-up transformers, generation interconnection line, main substation transformer, and reactive power devices. The existing and modified configurations for GEN-2002-008 are shown in Table ES-2 and Table ES-3 respectively. The sections of the modification table shaded in blue represent the MOD-32 modeling information provided by SPP that was included to ensure the most up to date information was modeled in this modification study.

**Table ES-1: GEN-2002-008 Existing Configuration**

| Request | Point of Interconnection | Existing Generator Configuration | GIA Capacity (MW) |
|---|---|---|---|
| GEN-2002-008 | Hitchland 345 kV (523097) | 160 x GE 1.5 MW (Wind) | 240 |

**Table ES-2: GEN-2002-008 Existing Configuration Details**

| Facility | Existing | | |
|---|---|---|---|
| Point of Interconnection | Hitchland 345 kV (523097) | | |
| Configuration/Capacity | 160 x GE 1.5 MW (Wind) = 240 MW | | |
| Generation Interconnection Line 115 kV | NOBLE_WND3 to NBLWND-HV2:<br>Length = 0 miles<br>R = 0.013980 pu<br>X = 0.056700 pu<br>B = 0.000020 pu<br>Rating A MVA = 270.4 MVA<br>Rating B MVA = 296.8 MVA | | NOBLE_WND3 to NBLWND-HV3:<br>Length = 0 miles<br>R = 0.004190 pu<br>X = 0.017010 pu<br>B = 0.000010 pu<br>Rating A MVA = 270.4 MVA<br>Rating B MVA = 296.8 MVA |
| Main Substation Transformer[1] 345/115/13.8 kV | X12 = 4.203% R12 = 0.068%, X23 = 7.445% R23 = 0.207%, X13 = 12.445% R13 = 0.215%,<br>Winding MVA = 100 MVA,<br>Winding 1 Rate A/B MVA = 270 MVA,<br>Winding 2 Rate A/B MVA = 270 MVA,<br>Winding 3 Rate A/B MVA = 64 MVA | | |
| Main Substation Transformer[1] 115/34.5 kV | X = 7.996% R = 0.267%,<br>Winding MVA = 54 MVA,<br>Rating MVA = 90 MVA | X = 7.996% R = 0.267%,<br>Winding MVA = 54 MVA,<br>Rating MVA = 90 MVA | X = 7.996% R = 0.267%,<br>Winding MVA = 54 MVA,<br>Rating MVA = 90 MVA |
| Equivalent GSU Transformer[1] | Gen 1 Equivalent Qty: 53: (Wind) | Gen 2 Equivalent Qty: 52: (Wind) | Gen 3 Equivalent Qty: 55: (Wind) |
| | X = 6.243%, R = 0.83%,<br>Winding MVA = 92.75 MVA,<br>Rating MVA[2] = 92.8 MVA | X = 6.363%, R = 0.846%,<br>Winding MVA = 91 MVA,<br>Rating MVA = 91 MVA | X = 6.016%, R = 0.8%,<br>Winding MVA = 96.25 MVA,<br>Rating MVA[2] = 96.3 MVA |
| Equivalent Collector Line[3] | R = 0.011420 pu<br>X = 0.047630 pu<br>B = 0.003160 pu | R = 0.018950 pu<br>X = 0.067890 pu<br>B = 0.003690 pu | R = 0.009600 pu<br>X = 0.043700 pu<br>B = 0.005060 pu |
| Reactive Power Devices | 1 x 15 MVAR 34.5 kV Capacitor Bank | 1 x 15 MVAR 34.5 kV Capacitor Bank | 1 x 15 MVAR 34.5 kV Capacitor Bank |

1) X/R based on Winding MVA, 2) Rating rounded in PSS/E, 3) all pu are on 100 MVA Base

**Table ES-3: GEN-2002-008 Modification Request Details**

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<tr><th>Facility</th><th colspan="4">Modification</th></tr>
<tr><td>Point of Interconnection</td><td colspan="4">Hitchland 345 kV (523097)</td></tr>
<tr><td>Configuration/Capacity</td><td colspan="4">76 x GE 1.5 MW (Wind) = 114 MW<br>38 x Power Electronics FP4390K 4.389 MW (Battery) = 166.782 MW (PPC to limit generator output to 126 MW)<br>PPC to limit total POI injection (Wind + Battery) to 240 MW</td></tr>
<tr><td>Generation Interconnection Line 115 kV</td><td>NOBLE_WND3 to GRPLAINS-HV2:<br>Length = 1.298 miles<br>R = 0.000641 pu<br>X = 0.005130 pu<br>B = 0.001392 pu<br>Rating A/B MVA = 361 MVA</td><td>GRPLAINS-HV2 to GRPLAINS-HSF:<br>Length = 0.167 miles<br>R = 0.000389 pu<br>X = 0.000974 pu<br>B = 0.001500 pu<br>Rating A/B MVA = 162.5 MVA</td><td>GRPLAINS-HSF to HSFD-MPT1:<br>Length = 0.17 miles<br>R = 0.000210 pu<br>X = 0.000558 pu<br>B = 0.007682 pu<br>Rating A/B MVA = 162.5 MVA</td><td>GRPLAINS-HSF to GRPLAINS-HV4:<br>Length = 3.355 miles<br>R = 0.007794 pu<br>X = 0.019521 pu<br>B = 0.030063 pu<br>Rating A/B MVA = 105 MVA</td></tr>
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<tr><td>Main Substation Transformer[1]<br>115/34.5 kV</td><td>X = 7.993% R = 0.232%,<br>Winding MVA = 54 MVA,<br>Rating MVA = 90 MVA</td><td colspan="2">X = 8.994% R = 0.329%,<br>Winding MVA = 94 MVA,<br>Rating MVA = 156 MVA</td><td>X = 7.929% R = 0.229%,<br>Winding MVA = 54 MVA,<br>Rating MVA = 90 MVA</td></tr>
<tr><td rowspan="2">Equivalent GSU Transformer[1]</td><td>Gen 1 Equivalent Qty: 53: (Wind)</td><td colspan="2">Gen 2 Equivalent Qty: 38: (Battery)</td><td>Gen 3 Equivalent Qty: 23: (Wind)</td></tr>
<tr><td>X = 5.684%, R = 0.866%,<br>Winding MVA = 92.8 MVA,<br>Rating MVA = 92.8 MVA</td><td colspan="2">X = 5.692%, R = 0.813%,<br>Winding MVA = 159.6 MVA,<br>Rating MVA = 159.6 MVA</td><td>X = 5.684%, R = 0.866%,<br>Winding MVA = 40.3 MVA,<br>Rating MVA = 40.3 MVA</td></tr>
<tr><td>Equivalent Collector Line[3]</td><td>R = 0.006262 pu<br>X = 0.006554 pu<br>B = 0.025173 pu</td><td colspan="2">R = 0.000385 pu<br>X = 0.000552 pu<br>B = 0.001039 pu</td><td>R = 0.009430 pu<br>X = 0.007310 pu<br>B = 0.008560 pu</td></tr>
<tr><td>Reactive Power Devices</td><td>N/A</td><td colspan="2">2 x 17 MVAR 34.5 kV Capacitor Bank</td><td>N/A</td></tr>
</table>

1) X/R based on Winding MVA, 2) Rating rounded in PSS/E, 3) all pu are on 100 MVA Base
Sections shaded in blue represent information from the MOD-32 modeling

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.77% compared to the DISIS-2017-001 power flow models. However, SPP determined that the short circuit and dynamic stability analyses were required because of the addition of a Battery Energy Storage System (BESS), 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-2017-001 Group 2 study models:

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

All analyses were performed using the PTI PSS/E version 33.10 software and the results are summarized below.

The results of the charging current compensation analysis performed using the 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak models showed that the GEN-2002-008 project needed 6.83 MVAr of reactor shunts on the 34.5 kV bus of the project substation with the modifications in place, an increase from the 1.1 MVAr found for the existing GEN-2002-008 configuration calculated using the DISIS-2017-001 models. 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-2002-008 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2002-008 POI was not greater than 0.61 kA for the 2021SP and 2028SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2002-008 generators online were below 30 kA for the 2021SP and 2028SP models.

The dynamic stability analysis was performed using the four modified study models, 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak. Up to 110 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breakers faults.

The results of the dynamic stability analysis showed that there were two types of existing stability issues. First, FLT1012-SB is a stuck breaker fault at the Finnley 345 kV bus that isolates GEN-2008-018, GEN-2017-032, and the Lamar HVDC line. In addition, oscillations were found for numerous faults in the 19WP and 21LL cases from the G08-047 (515905), HOLCGEN1 (531447), HARRNGTON (523971, 523972, 523973) and NICHOLS (524023) units. These issues were observed in both the pre and post modification cases so they were not attributed to this modification request.

There were no damping or voltage recovery violations attributed to the GEN-2002-008 project observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

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

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

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

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

# 1.0 Scope of Study

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2002-008. 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 33.10 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-2002-008 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-2002-008 is an active Interconnection Request with a queue status of “IA FULLY EXECUTED/COMMERCIAL OPERATION.” GEN-2002-008 is a wind farm and has a maximum summer and winter queue capacity of 240 MW with Energy Resource Interconnection Service (ERIS).

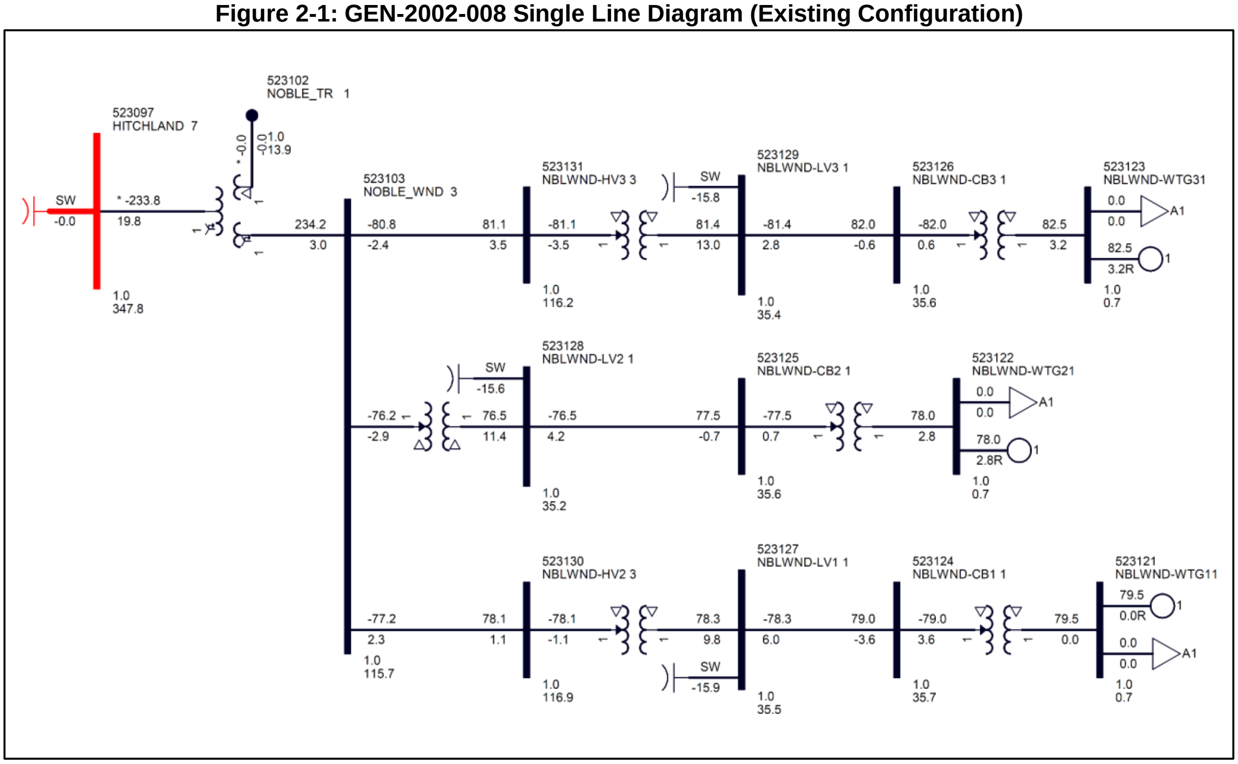
The GEN-2002-008 project was last studied as an Impact Study in August of 2007[1]. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2002-008 configuration.

The GEN-2002-008 project is proposed to interconnect in the Southwestern Public Service Company (SWPS) control area with a capacity of 240 MW as shown in Table 2-1 below.

**Table 2-1: GEN-2002-008 Existing Configuration**

| Request | Point of Interconnection | Existing Generator Configuration | GIA Capacity (MW) |
|---|---|---|---|
| GEN-2002-008 | Hitchland 345 kV (523097) | 160 x GE 1.5 MW (Wind) | 240 |

**Figure 2-1: GEN-2002-008 Single Line Diagram (Existing Configuration)**




This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2002-008 which changes the turbine configuration to 76 x GE 1.5 MW (wind) + 38 x Power

[1] Impact Study For Generation Interconnection Request GEN-2002-008, August 2007

Electronics FP4390K 4.389 MW (battery) for a total generating capacity of 280.782 MW. The generating capacity for GEN-2002-008 (280.782 MW) exceeds the total Generator Interconnection Agreement (GIA) Interconnection Service amount, 240 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 battery generator output to 126 MW and limit the total power injected into the POI to 240 MW.

In addition, the modification request included changes to the collection system, generator step-up transformers, generation interconnection line, main substation transformer, and reactive power devices. Figure 2-2 shows the power flow model single line diagram for the GEN-2002-008 modification. The existing and modified configurations for GEN-2002-008 are shown in Table 2-2 and Table 2-3 respectively. The sections of the modification table shaded in blue represent the MOD-32 modeling information provided by SPP that was included to ensure the most up to date information was modeled in this modification study.

**Figure 2-2: GEN-2002-008 Single Line Diagram (Modification Configuration)**

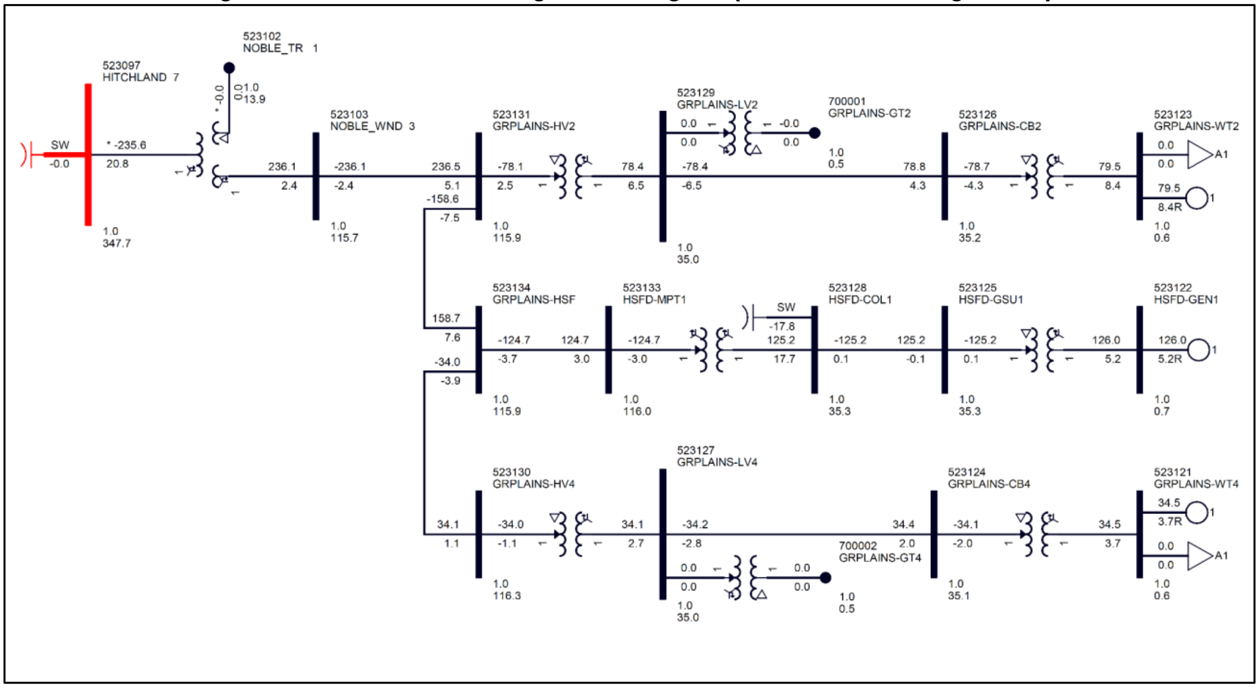


**Table 2-2: GEN-2002-008 Modification Request (Existing)**

| Facility | Existing | | |
|---|---|---|---|
| Point of Interconnection | Hitchland 345 kV (523097) | | |
| Configuration/Capacity | 160 x GE 1.5 MW (Wind) = 240 MW | | |
| Generation Interconnection Line 115 kV | NOBLE_WND3 to NBLWND-HV2:<br>Length = 0 miles<br>R = 0.013980 pu<br>X = 0.056700 pu<br>B = 0.000020 pu<br>Rating A MVA = 270.4 MVA<br>Rating B MVA = 296.8 MVA | | NOBLE_WND3 to NBLWND-HV3:<br>Length = 0 miles<br>R = 0.004190 pu<br>X = 0.017010 pu<br>B = 0.000010 pu<br>Rating A MVA = 270.4 MVA<br>Rating B MVA = 296.8 MVA |
| Main Substation Transformer[1] 345/115/13.8 kV | X12 = 4.203% R12 = 0.068%, X23 = 7.445% R23 = 0.207%, X13 = 12.445% R13 = 0.215%,<br>Winding MVA = 100 MVA,<br>Winding 1 Rate A/B MVA = 270 MVA,<br>Winding 2 Rate A/B MVA = 270 MVA,<br>Winding 3 Rate A/B MVA = 64 MVA | | |
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| Equivalent GSU Transformer[1] | Gen 1 Equivalent Qty: 53: (Wind) | Gen 2 Equivalent Qty: 52: (Wind) | Gen 3 Equivalent Qty: 55: (Wind) |
| | X = 6.243%, R = 0.83%,<br>Winding MVA = 92.75 MVA,<br>Rating MVA[2] = 92.8 MVA | X = 6.363%, R = 0.846%,<br>Winding MVA = 91 MVA,<br>Rating MVA = 91 MVA | X = 6.016%, R = 0.8%,<br>Winding MVA = 96.25 MVA,<br>Rating MVA[2] = 96.3 MVA |
| Equivalent Collector Line[3] | R = 0.011420 pu<br>X = 0.047630 pu<br>B = 0.003160 pu | R = 0.018950 pu<br>X = 0.067890 pu<br>B = 0.003690 pu | R = 0.009600 pu<br>X = 0.043700 pu<br>B = 0.005060 pu |
| Reactive Power Devices | 1 x 15 MVAR 34.5 kV Capacitor Bank | 1 x 15 MVAR 34.5 kV Capacitor Bank | 1 x 15 MVAR 34.5 kV Capacitor Bank |

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**Table 2-3: GEN-2002-008 Modification Request (Modified)**

<table>
<tr><th>Facility</th><th colspan="4">Modification</th></tr>
<tr><td>Point of Interconnection</td><td colspan="4">Hitchland 345 kV (523097)</td></tr>
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<tr><td>X = 5.684%, R = 0.866%,<br>Winding MVA = 92.8 MVA,<br>Rating MVA = 92.8 MVA</td><td colspan="2">X = 5.692%, R = 0.813%,<br>Winding MVA = 159.6 MVA,<br>Rating MVA = 159.6 MVA</td><td>X = 5.684%, R = 0.866%,<br>Winding MVA = 40.3 MVA,<br>Rating MVA = 40.3 MVA</td></tr>
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1) X/R based on Winding MVA, 2) Rating rounded in PSS/E, 3) all pu are on 100 MVA Base
Sections shaded in blue represent information from the MOD-32 modeling

# 3.0 Existing vs Modification Comparison

To determine which analyses are required for the Study, the differences between the existing configuration and the requested modification were evaluated. Aneden performed this comparison and the resulting analyses using a set of modified study models developed based on the modification request data and the DISIS-2017-001 Group 2 study models.

The methodology and results of the comparisons are described below. The analysis was completed using PSS/E version 33.10 software.

## 3.1 POI Injection Comparison

The real power injection at the POI was determined using PSS/E to compare the DISIS-2017-001 power flow configuration and the requested modifications for GEN-2002-008. The percentage change in the POI injection was then evaluated. If the MW difference was determined to be significant, power flow analysis would be performed to assess the impact of the modification request.

SPP determined that power flow analysis was not required due to the insignificant change (increase of 0.77%) 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-2002-008 POI Injection Comparison**

| Interconnection Request | Existing POI Injection (MW) | MRIS POI Injection (MW) | POI Injection Difference % |
|---|---|---|---|
| GEN-2002-008 | 233.8 | 235.6 | 0.77% |

## 3.2 Turbine Parameters Comparison

SPP determined that short circuit and dynamic stability analyses were required because of the addition of a Battery Energy Storage System (BESS), the project capacity increase, and the use of PPCs. This is because the short circuit contribution and stability responses of the existing configuration and the requested modification’s configuration may differ. The generator dynamic model for the modification can be found in Appendix A.

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

## 3.3 Equivalent Impedance Comparison Calculation

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

# 4.0 Charging Current Compensation Analysis

The charging current compensation analysis was performed for GEN-2002-008 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-2002-008 generators were switched out of service while other collection system elements remained in-service. A shunt reactor was tested at the project's collection substation 34.5 kV bus to 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-2002-008 project needed approximately 6.83 MVAr of compensation at its project collector substation, to reduce the POI MVAr to zero. This is an increase from the 1.1 MVAr found for the existing GEN-2002-008 configuration calculated using the DISIS-2017-001 models. Figure 4-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the existing configuration. Figure 4-2 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the updated topology. The final shunt reactor requirements for GEN-2002-008 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) | | | |
|---|---|---|---|---|---|---|
| | | | 19WP | 21LL | 21SP | 28SP |
| GEN-2002-008 | 523097 | Hitchland 345 kV | 6.83 | 6.83 | 6.83 | 6.83 |

**Figure 4-1: GEN-2002-008 Single Line Diagram (Existing Shunt Reactor)**

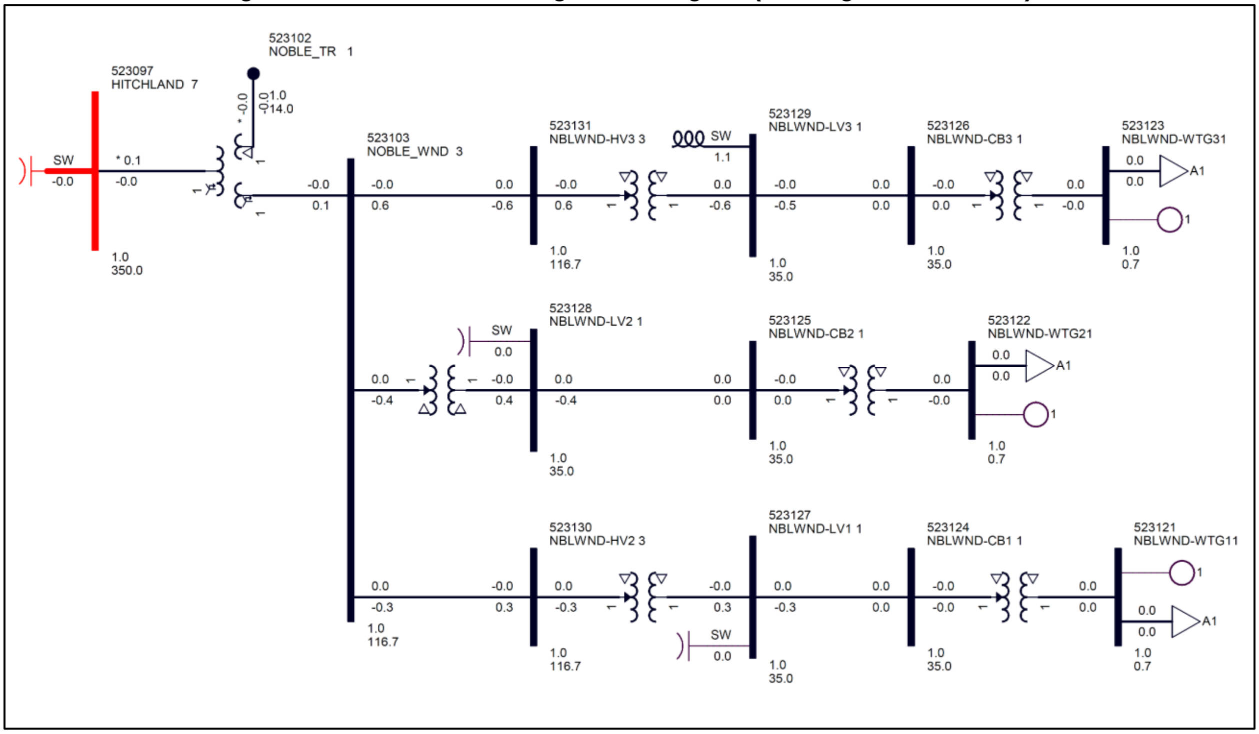
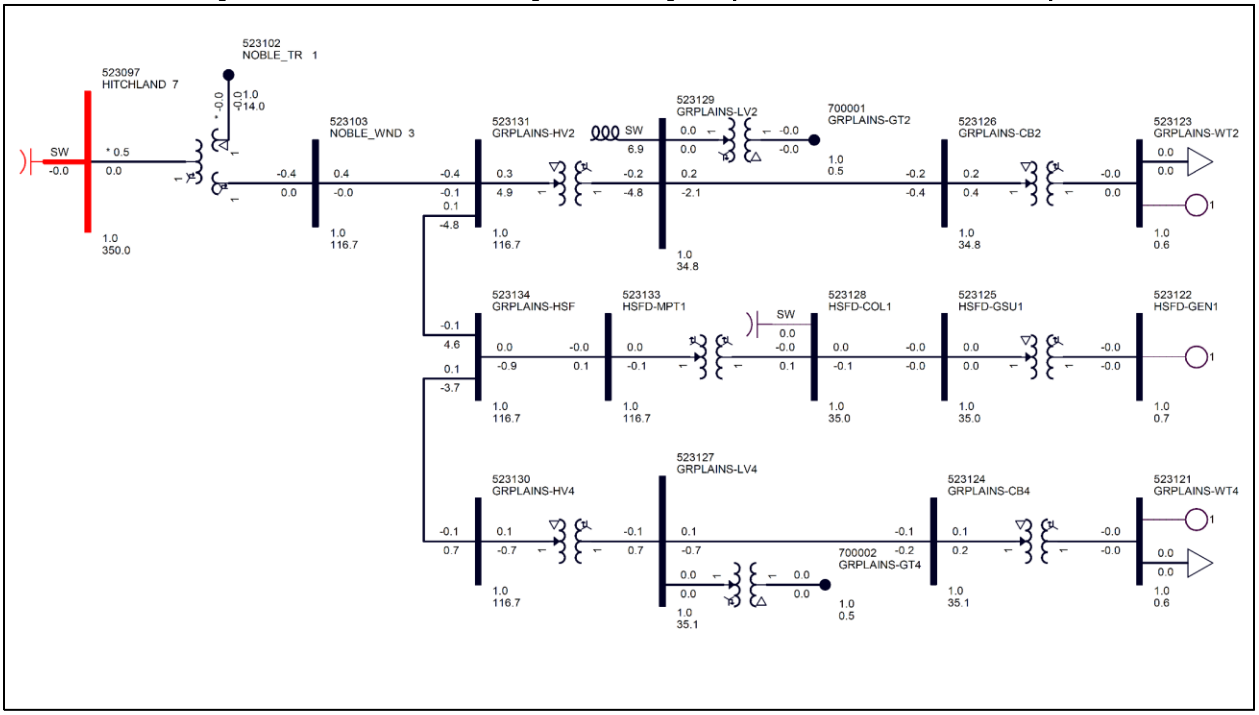



**Figure 4-2: GEN-2002-008 Single Line Diagram (Modification Shunt Reactor)**



# 5.0 Short Circuit Analysis

A short circuit study was performed using the 2021SP and 2028SP models for GEN-2002-008. The detailed results of the short circuit analysis are provided in Appendix B.

## 5.1 Methodology

The short circuit analysis included applying a 3-phase fault on buses up to 5 levels away from the 345 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels in the transmission system with and without GEN-2002-008 online.

## 5.2 Results

The results of the short circuit analysis for the 2021SP and 2028SP models are summarized in Table 5-1 through Table 5-3 respectively. The GEN-2002-008 POI bus fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 16.79 kA with the GEN-2002-008 project online.

The maximum fault current calculated within 5 buses of the GEN-2002-008 POI was less than 30 kA for the 2021SP and 2028SP models respectively. The maximum GEN-2002-008 contribution to three-phase fault current was about 3.8% and 0.61 kA.

**Table 5-1: POI Short Circuit Results**

| Case | GEN-OFF Current (kA) | GEN-ON Current (kA) | Max kA Change | Max %Change |
|---|---|---|---|---|
| 2021SP | 16.04 | 16.62 | 0.58 | 3.6% |
| 2028SP | 16.18 | 16.79 | 0.61 | 3.8% |

**Table 5-2: 2021SP Short Circuit Results**

| Voltage (kV) | Max. Current (kA) | Max kA Change | Max %Change |
|---|---|---|---|
| 69 | 8.4 | -0.01 | -0.1% |
| 115 | 29.8 | 0.11 | 0.6% |
| 138 | 24.9 | -0.02 | -0.3% |
| 230 | 26.8 | 0.21 | 1.4% |
| 345 | 24.6 | 0.58 | 3.6% |
| **Max** | **29.8** | **0.58** | **3.6%** |

**Table 5-3: 2028SP Short Circuit Results**

| Voltage (kV) | Max. Current (kA) | Max kA Change | Max %Change |
|---|---|---|---|
| 69 | 8.4 | 0.00 | -0.1% |
| 115 | 24.9 | 0.14 | 0.7% |
| 138 | 25.8 | -0.01 | -0.1% |
| 230 | 27.3 | 0.24 | 1.5% |
| 345 | 24.9 | 0.61 | 3.8% |
| **Max** | **27.3** | **0.61** | **3.8%** |

# 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-2002-008 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-2002-008 configuration of 76 x GE 1.5 MW (REGCAU1) + 38 x Power Electronics FP4390K 4.389 MW (REGCAU1). This stability analysis was performed using PTI's PSS/E version 33.10 software.

The stability models were developed using the DISIS-2017-001 Group 2 models. The modifications requested for the GEN-2002-008 projects were used to create modified stability models for this impact study.

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

1. The instantaneous overvoltage relays at buses 523170 and 523171 were disabled
2. The frequency protection relay at bus 588637 was disabled
3. Adjusted the Lamar HVDC RDC value from 0.04 to 0.4
4. Adjusted the GEN-2002-009 MVA base from 90 to 86.49
5. Adjusted the GEN-2002-009 Xsource from 0.3022 to 0.21157

The modified dynamics model data for the GEN-2002-008 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-2002-008 and other equally and prior queued projects in Group 2. In addition, voltages of five (5) buses away from the POI of GEN-2002-008 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-2002-008 and developed additional fault events as required. The new set of faults were simulated using the modified study models. The fault events included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults. The simulated faults are listed and described in Table 6-1 below. These contingencies were applied to the modified 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and the 2028 Summer Peak models.

**Table 6-1: Fault Definitions**

| Fault ID | Planning Event | Fault Descriptions |
|---|---|---|
| FLT01-3PH | P1 | 3 phase fault on the BVRCNTY7 (515554) to BALKOW7 (515618) 345 kV line circuit 1, near BVRCNTY7.<br>a. Apply fault at the BVRCNTY7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>**Trip generator BALKOWG1 (515658)**<br>**Trip generator BALKOWG2 (515659)**<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT02-3PH | P1 | 3 phase fault on the BVRCNTY7 (515554) to BADGER (515677) 345 kV line circuit 1, near BVRCNTY7.<br>a. Apply fault at the BVRCNTY7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT07-3PH | P1 | 3 phase fault on the TEXAS_CNTY 3 115 kV (523090) to HITCHLAND 3 (523093) 115 kV line circuit 1, near TEXAS_CNTY 3.<br>a. Apply fault at the TEXAS_CNTY 3 115 kV bus.<br>b. Clear fault after 7 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault. |
| FLT08-3PH | P1 | 3 phase fault on the HITCHLAND 3 115 kV (523093)/ 230 kV (523095) / 13.8 kV (523098) XFMR CKT 2, near HITCHLAND 3 115 kV.<br>a. Apply fault at the HITCHLAND 3 115 kV bus.<br>b. Clear fault after 7 cycles and trip the faulted transformer. |
| FLT09-3PH | P1 | 3 phase fault on the HITCHLAND 3 115 kV (523093) to HANSFORD 3 (523195) 115 kV line circuit 1, near HITCHLAND 3.<br>a. Apply fault at the HITCHLAND 3 115 kV bus.<br>b. Clear fault after 7 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault. |
| FLT10-3PH | P1 | 3 phase fault on the HITCHLAND 6 230 kV (523095) to MOORE_CNTY 6 (523309) 230 kV line circuit 1, near HITCHLAND 6.<br>a. Apply fault at the HITCHLAND 6 230 kV bus.<br>b. Clear fault after 7 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault. |
| FLT11-3PH | P1 | 3 phase fault on the HITCHLAND 230 kV (523095) / 345 kV (523097)/ 13.2 kV (523094) transformer CKT 2, near HITCHLAND 230kV.<br>a. Apply fault at the HITCHLAND 345 kV bus.<br>b. Clear fault after 7 cycles and trip the faulted transformer. |
| FLT12-3PH | P1 | 3 phase fault on the HITCHLAND 7 (523097) to POTTER_CO 7 (523961) 345 kV line circuit 1, near HITCHLAND 7.<br>a. Apply fault at the HITCHLAND 7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT13-3PH | P1 | 3 phase fault on the HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 1, near HITCHLAND.<br>a. Apply fault at the HITCHLAND 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT14-3PH | P1 | 3 phase fault on the HITCHLAND 7 (523097) to CARPENTER 7 (523823) 345 kV line circuit 1, near HITCHLAND 7.<br>a. Apply fault at the HITCHLAND 7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT19-3PH | P1 | 3 phase fault on the OCHILTREE 3 115 kV (523154) / 230 kV (523155) /13.8 kV (523151) XFMR CKT 1, near OCHILTREE 3 115 kV.<br>a. Apply fault at the OCHILTREE 3 115 kV bus.<br>b. Clear fault after 7 cycles and trip the faulted transformer. |

**Table 6-1 continued**

| Fault ID | Planning Event | Fault Descriptions |
|---|---|---|
| FLT21-3PH | P1 | 3 phase fault on the MOORE_E 3 115 kV (523308)/ 230 kV (523309) / 13.8 kV (523302) XFMR CKT 1, near MOORE_E 3 115 kV.<br>a. Apply fault at the MOORE_E 3 115 kV bus.<br>b. Clear fault after 7 cycles and trip the faulted transformer. |
| FLT22-3PH | P1 | 3 phase fault on the MOORE_CNTY 6 (523309) to POTTER_CO 6 (523959) 230 kV line circuit 1, near MOORE_CNTY 6.<br>a. Apply fault at the MOORE_CNTY 6 230 kV bus.<br>b. Clear fault after 7 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault. |
| FLT23-3PH | P1 | 3 phase fault on the HARBNGR3 345 kV (531512) /115 kV (531510) /13.8 kV (531511) XFMR CKT 1, near HARBNGR7 345kV.<br>a. Apply fault at the HARBNGR3 345 kV bus.<br>b. Clear fault after 6 cycles and trip the faulted transformer. |
| FLT24-3PH | P1 | 3 phase fault on the POTTER_CO 345 kV (523961) /230 kV (523959) /13.8 kV (523957) XFMR CKT 1, near POTTER_CO 345kV.<br>a. Apply fault at the POTTER_CO 345 kV bus.<br>b. Clear fault after 6 cycles and trip the faulted transformer. |
| FLT26-3PH | P1 | 3 phase fault on the BUSHLAND 230 kV (524267) /115 kV (524266) /13.2 kV (524263) XFMR CKT 1, near BUSHLAND 230 kV.<br>a. Apply fault at the BUSHLAND 230 kV bus.<br>b. Clear fault after 7 cycles and trip the faulted transformer. |
| FLT27-3PH | P1 | 3 phase fault on the POTTER_CO 6 (523959) to BUSHLAND 6 (524267) 230 kV line circuit 1, near POTTER_CO 6.<br>a. Apply fault at the POTTER_CO 6 230 kV bus.<br>b. Clear fault after 7 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault. |
| FLT39-3PH | P1 | 3 phase fault on the BUSHLAND 6 (524267) to DEAFSMITH 6 (524623) 230 kV line circuit 1, near BUSHLAND 6.<br>a. Apply fault at the BUSHLAND 6 230 kV bus.<br>b. Clear fault after 7 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault. |
| FLT60-3PH | P1 | 3 phase fault on the POTTER_CO 230 kV (523959) /345 kV (523961)/ 13.2 kV (523957) XFMR CKT 1, near POTTER_CO 230 kV.<br>a. Apply fault at the POTTER_CO 230 kV bus.<br>b. Clear fault after 7 cycles and trip the faulted transformer. |
| FLT66-3PH | P1 | 3 phase fault on the POTTER_CO 7 (523961) to HITCHLAND 7 (523097) 345 kV line circuit 1, near POTTER_CO 7.<br>a. Apply fault at the POTTER_CO 7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT67-3PH | P1 | 3 phase fault on the CHAN+TASCOS6 (523869) to XIT_INTG (523221) 230 kV line circuit 1, near CHAN+TASCOS6.<br>a. Apply fault at the CHAN+TASCOS6 230 kV bus.<br>b. Clear fault after 7 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault. |
| FLT68-3PH | P1 | 3 phase fault on the POTTER_CO 6 (523959) to MOORE_CNTY 6 (523309) 230 kV line circuit 1, near POTTER_CO 6.<br>a. Apply fault at the POTTER_CO 6 230 kV bus.<br>b. Clear fault after 7 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault. |

**Table 6-1 continued**

| Fault ID | Planning Event | Fault Descriptions |
|---|---|---|
| FLT70-3PH | P1 | 3 phase fault on the BADGER 7 (515677) to G16-003-TAP (560071) 345 kV line circuit 1, near BADGER 7.<br>a. Apply fault at the BADGER 7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT71-3PH | P1 | 3 phase fault on the G16-003-TAP (560071) to BADGER 7 (515677) 345 kV line circuit 1, near G16-003-TAP.<br>a. Apply fault at the G16-003-TAP 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT72-3PH | P1 | 3 phase fault on the CARPENTER 7 (523823) to FINNEY 7 (523853) 345 kV line circuit 1, near CARPENTER 7.<br>a. Apply fault at the CARPENTER 7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT129-3PH | P1 | 3 phase fault on the TEXAS_CNTY 3 115 kV (523090) to HITCHLAND 3 (523093) 115 kV line circuit 2, near TEXAS_CNTY 3.<br>a. Apply fault at the TEXAS_CNTY 3 115 kV bus.<br>b. Clear fault after 7 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault. |
| FLT137-3PH | P1 | 3 phase fault on the HITCHLAND 3 115 kV (523093)/ 230 kV (523095) / 13.8 kV (523092) XFMR CKT 1, near HITCHLAND 3 115 kV.<br>a. Apply fault at the HITCHLAND 3 115 kV bus.<br>b. Clear fault after 7 cycles and trip the faulted transformer. |
| FLT139-3PH | P1 | 3 phase fault on the HITCHLAND 230 kV (523095) /345 kV (523097) /13.2 kV (523091) transformer CKT 1, near HITCHLAND 230kV.<br>a. Apply fault at the HITCHLAND 230 kV bus.<br>b. Clear fault after 7 cycles and trip the faulted transformer. |
| FLT129-PO1 | P6 | **PRIOR OUTAGE of TEXAS_CNTY 3 115 kV (523090) to HITCHLAND 3 (523093) 115 kV line circuit 1**<br>3 phase fault on the TEXAS_CNTY 3 115 kV (523090) to HITCHLAND 3 (523093) 115 kV line circuit 2, near TEXAS_CNTY 3.<br>a. Apply fault at the TEXAS_CNTY 3 115 kV bus.<br>b. Clear fault after 7 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault. |
| FLT19-PO3 (136_P6) | P6 | **PRIOR OUTAGE of HITCHLAND 3 115 kV (523093) to HANSFORD 3 (523195) 115 kV line circuit 1**<br>3 phase fault on the OCHILTREE 3 115 kV (523154) / 230 kV (523155) /13.8 kV (523151) XFMR CKT 1, near OCHILTREE 3 115 kV.<br>a. Apply fault at the OCHILTREE 3 115 kV bus.<br>b. Clear fault after 7 cycles and trip the faulted transformer. |
| FLT137-PO4 | P6 | **PRIOR OUTAGE of HITCHLAND 3 115 kV (523093)/ 230 kV (523095) / 13.8 kV (523098) XFMR CKT 2**<br>3 phase fault on the HITCHLAND 3 115 kV (523093)/ 230 kV (523095) / 13.8 kV (523092) XFMR CKT 1, near HITCHLAND 3 115 kV.<br>a. Apply fault at the HITCHLAND 3 115 kV bus.<br>b. Clear fault after 7 cycles and trip the faulted transformer. |
| FLT12-PO5 (138_P6) | P6 | **PRIOR OUTAGE of HITCHLAND 6 230 kV (523095) to MOORE_CNTY 6 (523309) 230 kV line circuit 1**<br>3 phase fault on the HITCHLAND 7 (523097) to POTTER_CO 7 (523961) 345 kV line circuit 1, near HITCHLAND 7.<br>a. Apply fault at the HITCHLAND 7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |

**Table 6-1 continued**

| Fault ID | Planning Event | Fault Descriptions |
|---|---|---|
| FLT139-PO6 | P6 | **PRIOR OUTAGE of HITCHLAND 345 kV (523097) /230 kV (523095) /13.2 kV (523094) transformer CKT 2**<br>3 phase fault on the HITCHLAND 345 kV (523097) /230 kV (523095) /13.19 kV (523091) transformer CKT 1, near HITCHLAND 230kV.<br>a. Apply fault at the HITCHLAND 230 kV bus.<br>b. Clear fault after 7 cycles and trip the faulted transformer. |
| FLT14-PO2 (140_P6) | P6 | **PRIOR OUTAGE of HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 1**<br>3 phase fault on the HITCHLAND 7 (523097) to CARPENTER 7 (523823) 345 kV line circuit 1, near HITCHLAND 7.<br>a. Apply fault at the HITCHLAND 7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT13-PO7 (141_P6) | P6 | **PRIOR OUTAGE of HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 2**<br>3 phase fault on the HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 1, near HITCHLAND.<br>a. Apply fault at the HITCHLAND 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9001-3PH | P1 | 3 phase fault on the HITCHLAND 7 (523097) to NOVUS1 7 (523112) 345 kV line circuit 1, near HITCHLAND 7.<br>a. Apply fault at the HITCHLAND 7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>**Trip generator G06-044GEN2A (579376)**<br>**Trip generator NOVUS_WND 1 (523107)**<br>**Trip generator G06-044GEN1A (579373)**<br>**Trip generator G06-044GEN2B (579380)**<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9002-3PH | P1 | 3 phase fault on the HITCHLAND 7 (523097) to GEN-2010-014 (576395) 345 kV line circuit 1, near HITCHLAND 7.<br>a. Apply fault at the HITCHLAND 7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>**Trip generator G10-014-GEN1 (576400)**<br>**Trip generator G10-014-GEN2 (576410)**<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9003-3PH | P1 | 3 phase fault on the HITCHLAND 7 (523097) to FREWHELCOL7 (523215) 345 kV line circuit 1, near HITCHLAND 7.<br>a. Apply fault at the HITCHLAND 7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>**Trip generator FREWHEL-GEN1 (599148)**<br>**Trip generator FREWHEL-GEN2 (599150)**<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9004-3PH | P1 | 3 phase fault on the HITCHLAND 345 kV (523097) /230 kV (523095) /13.2 kV (523091) transformer CKT 1, near HITCHLAND 230kV.<br>a. Apply fault at the HITCHLAND 345 kV bus.<br>b. Clear fault after 6 cycles and trip the faulted transformer. |
| FLT9005-3PH | P1 | 3 phase fault on the CLARKCOUNTY7 (539800) to GEN-2011-008 (582008) 345 kV line circuit 1, near CLARKCOUNTY7.<br>a. Apply fault at the CLARKCOUNTY7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>**Trip generator G11-008-GEN1 (582208)**<br>**Trip generator G11-008-GEN2 (582598)**<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9006-3PH | P1 | 3 phase fault on the CARPENTER 7 (523823) to HARBNG7 (531512) 345 kV line circuit 1, near CARPENTER 7.<br>a. Apply fault at the CARPENTER 7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |

**Table 6-1 continued**

| Fault ID | Planning Event | Fault Descriptions |
|---|---|---|
| FLT9007-3PH | P1 | 3 phase fault on the FINNEY 7 (523853) to HOLCOMB7 (531449) 345 kV line circuit 1, near FINNEY 7.<br>a. Apply fault at the FINNEY 7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9008-3PH | P1 | 3 phase fault on the FINNEY 7 (523853) to BUFF_DUNES7 (523118) 345 kV line circuit 1, near FINNEY 7.<br>a. Apply fault at the FINNEY 7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>**Trip generator G08-018-GEN1 (579403)**<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9009-3PH | P1 | 3 phase fault on the FINNEY 7 (523853) to G17-032-TAP (588754) 345 kV line circuit 1, near FINNEY 7.<br>a. Apply fault at the FINNEY 7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>**Trip generator G17-032-GEN1 (588753)**<br>**Trip generator LAMAR 6 (599951)**<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9010-3PH | P1 | 3 phase fault on the HITCHLAND 3 230 kV (523095) /115 kV (523093)/ 13.2 kV (523092) XFMR CKT 1, near HITCHLAND 3 230 kV.<br>a. Apply fault at the HITCHLAND 3 230 kV bus.<br>b. Clear fault after 7 cycles and trip the faulted transformer. |
| FLT9011-3PH | P1 | 3 phase fault on the HITCHLAND 6 230 kV (523095) to OCHILTREE (523155) 230 kV line circuit 1, near HITCHLAND 6.<br>a. Apply fault at the HITCHLAND 6 230 kV bus.<br>b. Clear fault after 7 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault. |
| FLT9012-3PH | P1 | 3 phase fault on the POTTER_CO 7 (523961) to SPNSPUR_WND7 (524296) 345 kV line circuit 1, near POTTER_CO 7.<br>a. Apply fault at the POTTER_CO 6 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>**Trip generator G08-051-GEN2 (579413)**<br>**Trip generator SPNSPUR_WND1 (599106)**<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9013-3PH | P1 | 3 phase fault on the BVRCNTY7 (515554) to PALDR2W7 (515590) 345 kV line circuit 1, near BVRCNTY7.<br>a. Apply fault at the BVRCNTY7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>**Trip generator G08-047-GEN2 (573510)**<br>**Trip generator G08-047-GEN1 (515905)**<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9014-3PH | P1 | 3 phase fault on the BVRCNTY7 (515554) to CLARKCOUNTY7 (539800) 345 kV line circuit 1, near BVRCNTY7.<br>a. Apply fault at the BVRCNTY7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9015-3PH | P1 | 3 phase fault on the BVRCNTY7 (515554) to GRAPEVINE (560035) 345 kV line circuit 1, near BVRCNTY7.<br>a. Apply fault at the BVRCNTY7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9016-3PH | P1 | 3 phase fault on the GRAPEVINE (560035) to POTTER_CO 7 (523961) 345 kV line circuit 1, near GRAPEVINE.<br>a. Apply fault at the GRAPEVINE 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |

**Table 6-1 continued**

| Fault ID | Planning Event | Fault Descriptions |
|---|---|---|
| FLT9017-3PH | P1 | 3 phase fault on the GRAPEVINE (560035) to CHISHOLM7 (511553) 345 kV line circuit 1, near GRAPEVINE.<br>a. Apply fault at the GRAPEVINE 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9018-3PH | P1 | 3 phase fault on the BADGER 7 (515677) to GEN-2011-014 (515686) 345 kV line circuit 1, near BADGER 7.<br>a. Apply fault at the BADGER 7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9019-3PH | P1 | 3 phase fault on the BADGER 7 (515677) to GEN-2015-082 (585190) 345 kV line circuit 1, near BADGER 7.<br>a. Apply fault at the BADGER 7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>**Trip generator G15-082-GEN1 (585193)**<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9020-3PH | P1 | 3 phase fault on the CLARKCOUNTY7 (539800) to SPERVIL7 (531469) 345 kV line circuit 1, near CLARKCOUNTY7.<br>a. Apply fault at the CLARKCOUNTY7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9021-3PH | P1 | 3 phase fault on the CLARKCOUNTY7 (539800) to THISTLE7 (539801) 345 kV line circuit 1, near CLARKCOUNTY7.<br>a. Apply fault at the CLARKCOUNTY7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9022-3PH | P1 | 3 phase fault on the THISTLE7 (539801) to BUFFALO7 (532782) 345 kV line circuit 1, near THISTLE7.<br>a. Apply fault at the THISTLE7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9023-3PH | P1 | 3 phase fault on the THISTLE7 (539801) to GEN-2017-018 (588630) 345 kV line circuit 1, near THISTLE7.<br>a. Apply fault at the THISTLE7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>**Trip generator G17-018-GEN1 (588633)**<br>**Trip generator G17-018-GEN2 (588637)**<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9024-3PH | P1 | 3 phase fault on the THISTLE7 345 kV (539801) /138 kV (539804) /13.8 kV (539802) transformer CKT 1, near THISTLE7 345kV.<br>a. Apply fault at the HITCHLAND 345 kV bus.<br>b. Clear fault after 6 cycles and trip the faulted transformer. |
| FLT9025-3PH | P1 | 3 phase fault on the THISTLE7 (539801) to DGRASSE7 (515852) 345 kV line circuit 1, near THISTLE7.<br>a. Apply fault at the THISTLE7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9026-3PH | P1 | 3 phase fault on the CLARKCOUNTY7 (539800) to GEN-2012-024 (583370) 345 kV line circuit 1, near CLARKCOUNTY7.<br>a. Apply fault at the CLARKCOUNTY7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>**Trip generator G12-024-GEN1 (583373)**<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |

**Table 6-1 continued**

| Fault ID | Planning Event | Fault Descriptions |
|---|---|---|
| FLT9027-3PH | P1 | 3 phase fault on the CLARKCOUNTY7 (539800) to P1 MPT PRI (539852) 345 kV line circuit 1, near CLARKCOUNTY7.<br>a. Apply fault at the CLARKCOUNTY7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>**Trip generator G11-008-GEN3 (582978)**<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9028-3PH | P1 | 3 phase fault on the CLARKCOUNTY7 (539800) to G16-046-TAP (560080) 345 kV line circuit 1, near CLARKCOUNTY7.<br>a. Apply fault at the CLARKCOUNTY7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9029-3PH | P1 | 3 phase fault on the HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 2, near HITCHLAND.<br>a. Apply fault at the HITCHLAND 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT1001-SB | P4 | **Stuck Breaker on at POTTER_CO 7 (523961) at 345kV bus**<br>a. Apply single-phase fault at POTTER_CO 7 (523961) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the Bus POTTER_CO 7 (523961).<br>**Trip generator BALKOWG1 (579413)**<br>**Trip generator BALKOWG2 (599106)** |
| FLT1002-SB | P4 | **Stuck Breaker on at CARPENTER 7 (523823) at 345kV bus**<br>a. Apply single-phase fault at CARPENTER 7 (523823) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the Bus CARPENTER 7 (523823). |
| FLT1003-SB | P4 | **Stuck Breaker on at BVRCNTY7 (515554) at 345kV bus**<br>a. Apply single-phase fault at BVRCNTY7 (515554) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the BVRCNTY7 (515554) to BADGER (515677) 345 kV line CKT 2.<br>d. Trip the BVRCNTY7 (515554) to BALKOW (515618) 345 kV line CKT 1.<br>Trip generator BALKOWG1 (515658)<br>Trip generator BALKOWG2 (515659) |
| FLT1004-SB | P4 | **Stuck Breaker on at BVRCNTY7 (515554) at 345kV bus**<br>a. Apply single-phase fault at BVRCNTY7 (515554) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the BVRCNTY7 (515554) to PALDR2W7 (515590) 345 kV line CKT 1.<br>d. Trip the BVRCNTY7 (515554) to HITCHLAND 7 (523097) 345 kV line CKT 1.<br>Trip generator G08-047-GEN1 (515905)<br>Trip generator G08-047-GEN2 (573510) |
| FLT1005-SB | P4 | **Stuck Breaker on at BVRCNTY7 (515554) at 345kV bus**<br>a. Apply single-phase fault at BVRCNTY7 (515554) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the BVRCNTY7 (515554) to HITCHLAND 7 (523097) 345 kV line CKT 1.<br>d. Trip the BVRCNTY7 (515554) to HITCHLAND 7 (523097) 345 kV line CKT 2. |
| FLT1006-SB | P4 | **Stuck Breaker on at BVRCNTY7 (515554) at 345kV bus**<br>a. Apply single-phase fault at BVRCNTY7 (515554) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the BVRCNTY7 (515554) to BADGER (515677) 345 kV line CKT 2.<br>d. Trip the BVRCNTY7 (515554) to BADGER (515677) 345 kV line CKT 1. |
| FLT1007-SB | P4 | **Stuck Breaker on at BVRCNTY7 (515554) at 345kV bus**<br>a. Apply single-phase fault at BVRCNTY7 (515554) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the BVRCNTY7 (515554) to HITCHLAND 7 (523097) 345 kV line CKT 2.<br>d. Trip the BVRCNTY7 (515554) to BALKOW (515618) 345 kV line CKT 1.<br>Trip generator BALKOWG1 (515658)<br>Trip generator BALKOWG2 (515659) |

**Table 6-1 continued**

| Fault ID | Planning Event | Fault Descriptions |
|---|---|---|
| FLT1008-SB | P4 | **Stuck Breaker on at BVRCNTY7 (515554) at 345kV bus**<br>a. Apply single-phase fault at BVRCNTY7 (515554) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the BVRCNTY7 (515554) to PALDR2W7 (515590) 345 kV line CKT 1.<br>d. Trip the BVRCNTY7 (515554) to BADGER (515677) 345 kV line CKT 1.<br>Trip generator G08-047-GEN1 (515905)<br>Trip generator G08-047-GEN2 (573510) |
| FLT1009-SB | P4 | **Stuck Breaker on at FINNEY (523853) at 345kV bus**<br>a. Apply single-phase fault at FINNEY (523853) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the FINNEY (523853) to BUFF_DUNES 7 (523118) 345kV line CKT 1.<br>d. Trip the FINNEY (523853) to G17-032-TAP (588754) 345kV line CKT 1.<br>**Trip Generator G08-018-GEN1 (579403).**<br>**Trip Generator LAMAR (599951).**<br>**Trip Generator G17-032-GEN1 (588753).** |
| FLT1010-SB | P4 | **Stuck Breaker on at FINNEY (523853) at 345kV bus**<br>a. Apply single-phase fault at FINNEY (523853) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the FINNEY (523853) to HOLCOMB7 (531449) 345kV line CKT 1.<br>d. Trip the FINNEY (523853) to G17-032-TAP (588754) 345kV line CKT 1.<br>**Trip Generator LAMAR (599951).**<br>**Trip Generator G17-032-GEN1 (588753).** |
| FLT1012-SB | P4 | **Stuck Breaker on at FINNEY (523853) at 345kV bus**<br>a. Apply single-phase fault at FINNEY (523853) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the FINNEY (523853) to HOLOCOMB (531449) 345kV line CKT 1.<br>d. Trip the FINNEY (523853) to CARPENTER 7 (523823) 345kV line CKT 1. |
| FLT1014-SB | P4 | **Stuck Breaker on at FINNEY (523853) at 345kV bus**<br>a. Apply single-phase fault at FINNEY (523853) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the FINNEY (523853) to BUFF_DUNES 7 (523118) 345kV line CKT 1.<br>d. Trip the FINNEY (523853) to CARPENTER 7 (523823) 345kV line CKT 1.<br>**Trip Generator G08-018-GEN1 (579403).** |
| FLT1015-SB | P4 | **Stuck Breaker on at HITCHLAND 6 (523095) at 230kV bus**<br>a. Apply single-phase fault at HITCHLAND 6 (523095) on the 230kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the HITCHLAND 230kV (523095) to HITCHLAND 115kV (523093) HITCHLAND 13.2kV (523092) XFMR CKT 1.<br>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**<br>a. Apply single-phase fault at HITCHLAND 6 (523095) on the 230kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the HITCHLAND 230kV (523095) to HITCHLAND 115kV (523093) HITCHLAND 13.2kV (523098) XFMR CKT 2.<br>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**<br>a. Apply single-phase fault at HITCHLAND 6 (523095) on the 230kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the HITCHLAND 230kV (523095) to HITCHLAND 115kV (523093) HITCHLAND 13.2kV (523092) XFMR CKT 1.<br>d. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1.<br>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**<br>a. Apply single-phase fault at HITCHLAND 6 (523095) on the 230kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the HITCHLAND 230kV (523095) to HITCHLAND 115kV (523093) HITCHLAND 13.2kV (523098) XFMR CKT 2.<br>d. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2.<br>e. Trip the HITCHLAND (523095) to Moore County 230kV (523309) line CKT 1. |

**Table 6-1 continued**

| Fault ID | Planning Event | Fault Descriptions |
|---|---|---|
| FLT1019-SB | P4 | **Stuck Breaker on at HITCHLAND 6 (523095) at 230kV bus**<br>a. Apply single-phase fault at HITCHLAND 6 (523095) on the 230kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the HITCHLAND 230kV (523095) to HITCHLAND 115kV (523093) HITCHLAND 13.2kV (523098) XFMR CKT 2.<br>d. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2.<br>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**<br>a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the HITCHLAND (523097) to POTTER_CO 7 345kV (523961) line CKT 1.<br>d. Trip the HITCHLAND 345kV (523097) to NOBLE_WND 3 115kV (523103) to NOBLE_TR 1 13.8kV (523102) XFMR CKT 1.<br>**Trip Generators GRPLINS-WT2 (523123), HSFD-GEN1 (523122), GRPLAINS-WT4 (523121).** |
| FLT1021-SB | P4 | **Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus**<br>a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1.<br>d. Trip the HITCHLAND (523097) to NOVUS1 (523112) 345kV line CKT 1.<br>**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**<br>a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the HITCHLAND (523097) to BVRCNTY7 (515554) 345kV line CKT 1.<br>d. Trip the HITCHLAND (523097) to NOVUS1 (523112) 345kV line CKT 1.<br>**Trip Generators G06-044GEN1A (579373), G06-044GEN2A (579376), G06-044GEN2B (579380) and NOVUS_WND (523107).** |
| FLT1023-SB | P4 | **Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus**<br>a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) to HITCHLAND 13.2kV (523094) XFMR CKT 2.<br>d. Trip the HITCHLAND (523097) to BVRCNTY7 (515554) 345kV line CKT 1.<br>e. Trip the Capbank. |
| FLT1024-SB | P4 | **Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus**<br>a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2.<br>d. Trip the HITCHLAND (523097) to BVRCNTY7 (515554) 345kV line CKT 2.<br>e. Trip the Capbank. |
| FLT1025-SB | P4 | **Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus**<br>a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2.<br>d. Trip the HITCHLAND 345kV (523097) to NOBLE_WND 3 115kV (523103) to NOBLE_TR 1 13.8kV (523102) XFMR CKT 1.<br>**Trip Generators GRPLINS-WT2 (523123), HSFD-GEN1 (523122), GRPLAINS-WT4 (523121).**<br>e. Trip the Capbank. |
| FLT1026-SB | P4 | **Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus**<br>a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the HITCHLAND (523097) to POTTER_CO 7 345kV (523961) line CKT 1.<br>d. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) to HITCHLAND 13.2kV (523091) XFMR CKT 1. |

**Table 6-1 continued**

| Fault ID | Planning Event | Fault Descriptions |
|---|---|---|
| FLT1027-SB | P4 | **Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus**<br>a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1.<br>d. Trip the HITCHLAND (523097) to GEN-2010-014 (576395) 345kV line CKT 1.<br>**Trip Generators G10-014-GEN1 (576400), G10-014-GEN2 (576410).** |
| FLT1028-SB | P4 | **Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus**<br>a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) to HITCHLAND 13.2kV (523091) XFMR CKT 1.<br>d. Trip the HITCHLAND 345kV (523097) to CARPENTER 7 (523823) 345kV line CKT 1. |
| FLT1029-SB | P4 | **Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus**<br>a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the HITCHLAND (523097) to BVRCNTY7 (515554) 345kV line CKT 2.<br>d. Trip the HITCHLAND (523097) to GEN-2010-014 (576395) 345kV line CKT 1.<br>**Trip Generators G10-014-GEN1 (576400), G10-014-GEN2 (576410).** |
| FLT1030-SB | P4 | **Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus**<br>a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2.<br>d. Trip the HITCHLAND 345kV (523097) to CARPENTER 7 (523823) 345kV line CKT 1.<br>e. Trip the Capbank. |
| FLT1031-SB | P4 | **Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus**<br>a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2.<br>d. Trip the HITCHLAND 7 (523097) to FREWHELCOL7 (523215) 345 kV line circuit 1.<br>**Trip Generators FREWHEL-GEN1 (599148), FREWHEL-GEN2 (599150).**<br>e. Trip the Capbank. |
| FLT1032-SB | P4 | **Stuck Breaker on at HITCHLAND 7 (523097) at 345kV bus**<br>a. Apply single-phase fault at HITCHLAND 7 (523097) on the 345kV bus.<br>b. After 16 cycles, trip the following elements<br>c. Trip the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1.<br>d. Trip the HITCHLAND 7 (523097) to FREWHELCOL7 (523215) 345 kV line circuit 1.<br>**Trip Generators FREWHEL-GEN1 (599148), FREWHEL-GEN2 (599150).** |
| FLT12-PO2 | P6 | **PRIOR OUTAGE of HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 1**<br>3 phase fault on the HITCHLAND (523097) to Potter_CO 7 345kV (523961) line CKT 1, near HITCHLAND.<br>a. Apply fault at the HITCHLAND 345kV bus.<br>b. Clear fault after 5 cycles and trip the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault. |
| FLT9004-PO2 | P6 | **PRIOR OUTAGE of HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 1**<br>3 phase fault on the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1, near HITCHLAND 345kV.<br>a. Apply fault at the HITCHLAND 345kV bus.<br>b. Clear fault after 6 cycles and trip the faulted transformer. |
| FLT9029-PO2 | P6 | **PRIOR OUTAGE of HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 1**<br>3 phase fault on the HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 2, near HITCHLAND.<br>a. Apply fault at the HITCHLAND 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |

**Table 6-1 continued**

| Fault ID | Planning Event | Fault Descriptions |
|---|---|---|
| FLT12-PO6 | P6 | **PRIOR OUTAGE of the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2;**<br>3 phase fault on the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1, near HITCHLAND.<br>a. Apply fault at the HITCHLAND 345kV bus.<br>b. Clear fault after 5 cycles and trip the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault. |
| FLT13-PO6 | P6 | **PRIOR OUTAGE of the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2;**<br>3 phase fault on the HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 1, near HITCHLAND.<br>a. Apply fault at the HITCHLAND 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT14-PO6 | P6 | **PRIOR OUTAGE of the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2;**<br>3 phase fault on the HITCHLAND (523097) to CARPENTER 7 345kV (523823) CKT 1, near HITCHLAND.<br>a. Apply fault at the HITCHLAND 345kV bus.<br>b. Clear fault after 5 cycles and trip the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault. |
| FLT9004-PO6 | P6 | **PRIOR OUTAGE of the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523094) XFMR CKT 2;**<br>3 phase fault on the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1, near HITCHLAND 345kV.<br>a. Apply fault at the HITCHLAND 345kV bus.<br>b. Clear fault after 6 cycles and trip the faulted transformer. |
| FLT12-PO7 | P6 | **PRIOR OUTAGE of HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 2**<br>3 phase fault on the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1, near HITCHLAND.<br>a. Apply fault at the HITCHLAND 345kV bus.<br>b. Clear fault after 5 cycles and trip the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault. |
| FLT14-PO7 | P6 | **PRIOR OUTAGE of HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 2**<br>3 phase fault on the HITCHLAND 7 (523097) to CARPENTER 7 (523823) 345 kV line circuit 1, near HITCHLAND 7.<br>a. Apply fault at the HITCHLAND 7 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9004-PO7 | P6 | **PRIOR OUTAGE of HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 2**<br>3 phase fault on the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1, near HITCHLAND 345kV.<br>a. Apply fault at the HITCHLAND 345kV bus.<br>b. Clear fault after 6 cycles and trip the faulted transformer. |
| FLT13-PO8 | P6 | **PRIOR OUTAGE of the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1;**<br>3 phase fault on the HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 1, near HITCHLAND.<br>a. Apply fault at the HITCHLAND 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT14-PO8 | P6 | **PRIOR OUTAGE of the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1;**<br>3 phase fault on the HITCHLAND (523097) to CARPENTER 7 345kV (523823) CKT 1, near HITCHLAND.<br>a. Apply fault at the HITCHLAND 345kV bus.<br>b. Clear fault after 5 cycles and trip the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>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-PO8 | P6 | **PRIOR OUTAGE of the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1;**<br>3 phase fault on the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1, near HITCHLAND 345kV.<br>a. Apply fault at the HITCHLAND 345kV bus.<br>b. Clear fault after 6 cycles and trip the faulted transformer. |
| FLT12-PO9 | P6 | **PRIOR OUTAGE of the HITCHLAND (523097) to CARPENTER 7 (523823) 345kV line CKT 1;**<br>3 phase fault on the HITCHLAND (523097) to Potter County 345kV (523961) line CKT 1, near HITCHLAND.<br>a. Apply fault at the HITCHLAND 345kV bus.<br>b. Clear fault after 5 cycles and trip the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault. |
| FLT13-PO9 | P6 | **PRIOR OUTAGE of the HITCHLAND (523097) to CARPENTER 7 (523823) 345kV line CKT 1;**<br>3 phase fault on the HITCHLAND (523097) to BVRCNTY7 (515554) 345 kV line circuit 1, near HITCHLAND.<br>a. Apply fault at the HITCHLAND 345 kV bus.<br>b. Clear fault after 6 cycles by tripping the faulted line.<br>c. Wait 20 cycles, and then re-close the line in (b) back into the fault.<br>d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9004-PO9 | P6 | **PRIOR OUTAGE of the HITCHLAND (523097) to CARPENTER 7 (523823) 345kV line CKT 1;**<br>3 phase fault on the HITCHLAND 345kV (523097) to HITCHLAND 230kV (523095) HITCHLAND 13.2kV (523091) XFMR CKT 1, near HITCHLAND 345kV.<br>a. Apply fault at the HITCHLAND 345kV bus.<br>b. Clear fault after 6 cycles and trip the faulted transformer. |

## 6.3 Results

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

**Table 6-2: GEN-2002-008 Dynamic Stability Results**

| Fault ID | 19WP | | | 21LL | | | 21SP | | | 26SP | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Volt Violation | Volt Recovery | Stable | Volt Violation | Volt Recovery | Stable | Volt Violation | Volt Recovery | Stable | Volt Violation | Volt Recovery | Stable |
| FLT01-3PH | Pass | Pass | Stable(2) | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT02-3PH | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT07-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT08-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT09-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT10-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT11-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT12-3PH | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT13-3PH | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT14-3PH | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT19-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT21-3PH | Pass | Pass | Stable | Pass | Pass | Stable | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT22-3PH | Pass | Pass | Stable | Pass | Pass | Stable | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT23-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT24-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT26-3PH | Pass | Pass | Stable | Pass | Pass | Stable | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT27-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT39-3PH | Pass | Pass | Stable | Pass | Pass | Stable | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT60-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT66-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT67-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT68-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT70-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT71-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT72-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT129-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT137-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |

**Table 6-2 continued**

| Fault ID | 19WP | | | 21LL | | | 21SP | | | 26SP | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Volt Violation | Volt Recovery | Stable | Volt Violation | Volt Recovery | Stable | Volt Violation | Volt Recovery | Stable | Volt Violation | Volt Recovery | Stable |
| FLT139-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9001-3PH | Pass | Pass | Stable(2) | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9002-3PH | Pass | Pass | Stable(2) | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9003-3PH | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9004-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9005-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9006-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9007-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9008-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9009-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9010-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9011-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9012-3PH | Pass | Pass | Stable | Pass | Pass | Stable | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9013-3PH | Pass | Pass | Stable(2) | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9014-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9015-3PH | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9016-3PH | Pass | Pass | Stable | Pass | Pass | Stable | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9017-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9018-3PH | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9019-3PH | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9020-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9021-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9022-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9023-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9024-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9025-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9026-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9027-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9028-3PH | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9029-3PH | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1001-SB | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |

**Table 6-2 continued**

| Fault ID | 19WP | | | 21LL | | | 21SP | | | 26SP | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Volt Violation | Volt Recovery | Stable | Volt Violation | Volt Recovery | Stable | Volt Violation | Volt Recovery | Stable | Volt Violation | Volt Recovery | Stable |
| FLT1002-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1003-SB | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1004-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1005-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1006-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1007-SB | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1008-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1009-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1010-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1012-SB | Pass | Pass | Stable(1) | Pass | Pass | Stable(1)(3) | Pass | Pass | Stable(1) | Pass | Pass | Stable(1) |
| FLT1014-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1015-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1016-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1017-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1018-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1019-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1020-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1021-SB | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1022-SB | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1023-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1024-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1025-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1026-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1027-SB | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1028-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1029-SB | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1030-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1031-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1032-SB | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT129-PO1 | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT14-PO2 | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |

**Table 6-2 continued**

| Fault ID | 19WP | | | 21LL | | | 21SP | | | 26SP | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Volt Violation | Volt Recovery | Stable | Volt Violation | Volt Recovery | Stable | Volt Violation | Volt Recovery | Stable | Volt Violation | Volt Recovery | Stable |
| FLT12-PO2 | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9004-PO2 | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9029-PO2 | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT19-PO3 | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT137-PO4 | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT12-PO5 | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT12-PO6 | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT13-PO6 | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT14-PO6 | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT139-PO6 | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9004-PO6 | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT12-PO7 | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT13-PO7 | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT14-PO7 | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9004-PO7 | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT13-PO8 | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT14-PO8 | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9004-PO8 | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT12-PO9 | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT13-PO9 | Pass | Pass | Stable | Pass | Pass | Stable(2) | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9004-PO9 | Pass | Pass | Stable | Pass | Pass | Stable(3) | Pass | Pass | Stable | Pass | Pass | Stable |

**(1) FLT1012-SB would isolate GEN-2008-018, GEN-2017-032, and Lamar HVDC from SPP system**
**(2) Sustainable oscillation in both DISIS case without modification and modified case from G08-047 (515905), HOLCGEN1 (531447), HARRNGTON (523971, 523972, 523973) and NICHOLS (524023)**
**(3) Sustainable oscillation in both DISIS case without modification and modified case from HOLCGEN1 (531447)**

FLT1012-SB, a stuck breaker fault at the Finnley 345 kV bus, isolates GEN-2008-018, GEN-2017-032, and the Lamar HVDC line. The issue was observed in the existing system prior to the modification request and is not attributed to this modification request.

Figure 6-1 shows an example of the oscillations found for numerous faults in the 19WP and 21LL cases from G08-047 (515905), HOLCGEN1 (531447), HARRNGTON (523971, 523972, 523973) and NICHOLS (524023). These oscillations was also present in the existing DISIS-2017-001 cases as shown in Figure 6-2, so it was not attributed to this modification request.

**Figure 6-1: FLT01-3PH Oscillations (19WP Modification Case)**

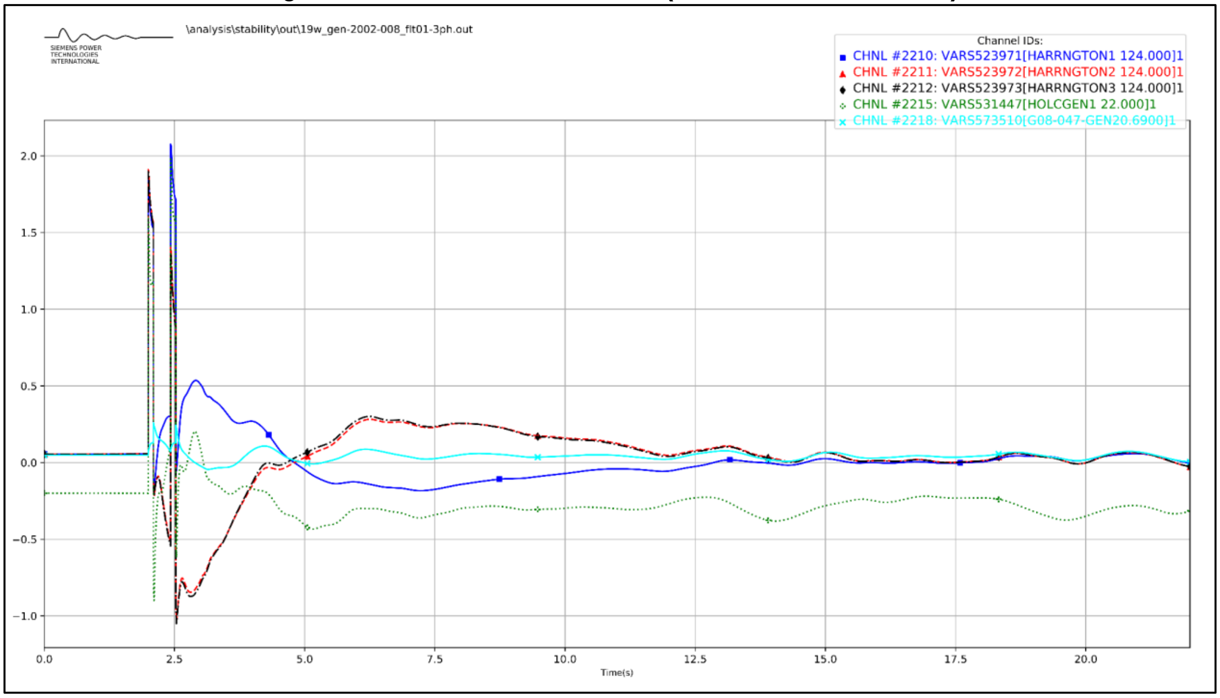
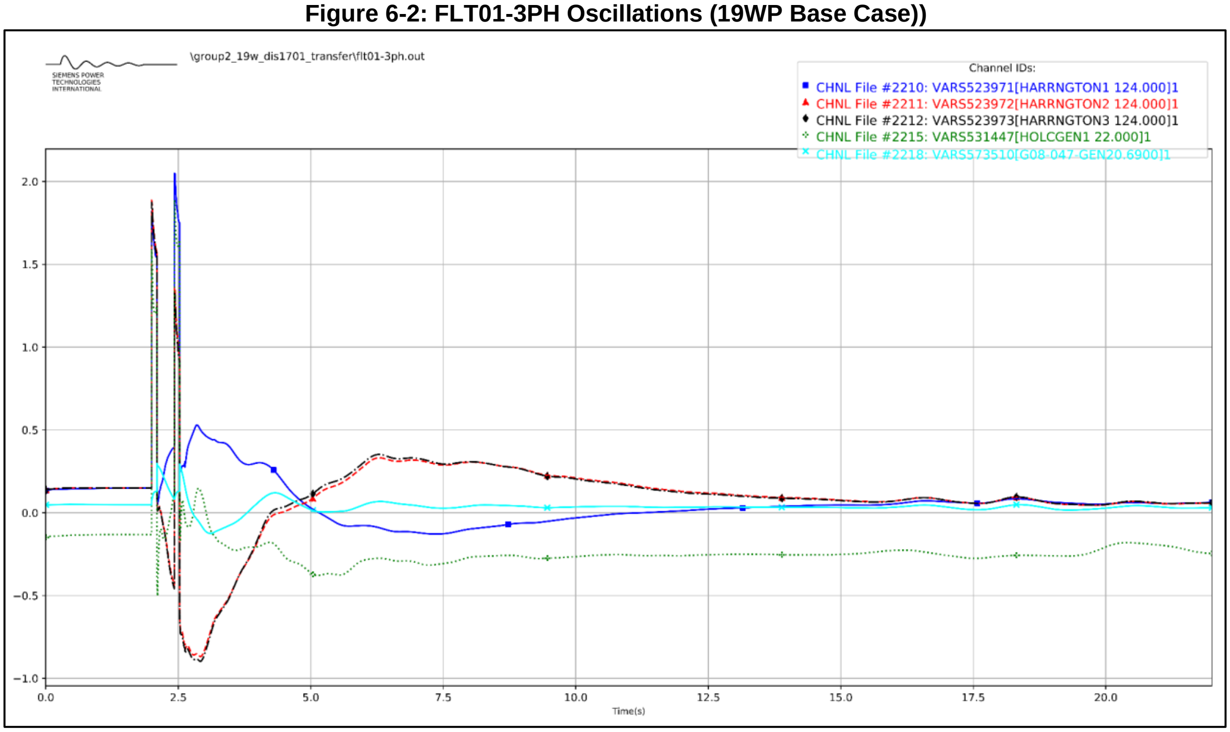



**Figure 6-2: FLT01-3PH Oscillations (19WP Base Case))**




There were no damping or voltage recovery violations attributed to the GEN-2002-008 project observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

# 7.0 Modified Capacity Exceeds GIA Capacity

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

As such, Interconnection Customers are allowed to increase the generating capacity of a generating facility without increasing its Interconnection Service amount 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-2002-008 (280.782 MW) exceeds the GIA Interconnection Service amount, 240 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-2002-008 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-2002-008 requested a Modification Request Impact Study to assess the impact of the turbine and facility change to a configuration of 76 x GE 1.5 MW (wind) + 38 x Power Electronics FP4390K 4.389 MW (battery) for a total generating capacity of 280.782 MW. The generating capacity for GEN-2002-008 (280.782 MW) exceeds the total Generator Interconnection Agreement (GIA) Interconnection Service amount, 240 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 battery generator output to 126 MW and to limit the total power injected into the POI to 240 MW.

In addition, the modification request included changes to the collection system, generator step-up transformers, generation interconnection line, main substation transformer, and reactive power devices. MOD-32 modeling information provided by SPP was included to ensure the most up to date information was modeled in this modification study.

SPP determined that power flow should not be performed based on the POI MW injection increase of 0.77% compared to the DISIS-2017-001 power flow models. However, SPP determined that the short circuit and dynamic stability analyses were required because of the addition of a Battery Energy Storage System (BESS), the project capacity increase, and the use of PPCs.

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 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak models showed that the GEN-2002-008 project needed 6.83 MVAr of reactor shunts on the 34.5 kV bus of the project substation with the modifications in place, an increase from the 1.1 MVAr found for the existing GEN-2002-008 configuration calculated using the DISIS-2017-001 models. 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-2002-008 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2002-008 POI was not greater than 0.61 kA for the 2021SP and 2028SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2002-008 generators online were below 30 kA for the 2021SP and 2028SP models.

The dynamic stability analysis was performed using the four modified study models, 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak. Up to 110 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breakers faults.

The results of the dynamic stability analysis showed that there were two types of existing stability issues. First, FLT1012-SB is a stuck breaker fault at the Finnley 345 kV bus that isolates GEN-2008-018, GEN-2017-032, and the Lamar HVDC line. In addition, oscillations were found for numerous faults in the 19WP and 21LL cases from the G08-047 (515905), HOLCGEN1 (531447), HARRNGTON (523971, 523972, 523973) and NICHOLS (524023) units. These issues were observed in both the pre and post modification cases so they were not attributed to this modification request.

There were no damping or voltage recovery violations attributed to the GEN-2002-008 project observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

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

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

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

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