

GEN-2013-002 &

GEN-2013-019

Modification Request Impact Study

By SPP Generator Interconnection

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# Revision History

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# Executive Summary

Southwest Power Pool performed a Modification Request Impact Study (Study) for GEN-2013-002 and GEN-2013-019, an active Generation Interconnection Request (GIR) with a Point of Interconnection (POI) at the Monolith 115 kV Substation.

The GEN-2013-002 and GEN-2013-019 project interconnects in the Nebraska Public Power District (NPPD) control area with a capacity of 124.2 MW as shown in Table ES‑1 below. This Study has been requested to evaluate the modification of GEN-2013-002 and GEN-2013-019 to change the configuration to 16 x GE 3.4 MW wind turbines (GEWTG0705), 2 x GE 2.82 MW wind turbines (GEWTG0705), 25 x Power Electronics 4.01 MVA solar inverters (REGCAU1), and use of a Power Plant Controller (PPC) to limit the total power injected into the POI. The generating capacity for GEN-2013-002 and GEN-2013-019 (148.26 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 124.2 MW, as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA. In addition, the modification request included changes to the collection system, generator step-up transformer, generation interconnection line, main substation transformer, and reactive power devices. The existing and modified configurations for GEN-2013-002 and GEN-2013-019 are shown in Table ES‑2.

Table ES‑1: GEN-2013-002 and GEN-2013-019 Existing Configuration

|  |  |  |  |
| --- | --- | --- | --- |
| Request | Point of Interconnection | Existing Generator Configuration | GIA Capacity (MW) |
| GEN-2013-002 and GEN-2013-019 | Monolith 115 kV Substation (640591) | 22 x GE 2.3 MW  32 x GE 2.3 MW | 124.2 |

Table ES‑2: GEN-2013-002 and GEN-2013-019 Modification Request

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| Facility | Existing Generating Facility Configuration | | Modification Generating Facility Configuration | | | |
| Point of Interconnection | Monolith 115 kV Substation (640591) | | Monolith 115 kV Substation (640591) | | | |
| Configuration/Capacity | 22 x GE 2.3 MW Wind Turbines = 50.6MW 32 x GE 2.3MW Wind Turbines = 73.6MW | | 16 x GE 3.4 MW Wind Turbines = 54.4MW 2 x GE 2.82 MW Wind Turbines = 5.64 25 x PE 4.01 MVA Solar Inverters = 88.22MW ***POI Injection limited to 124.2 MW*** | | | |
| Generation Interconnection Line | Length = 0.8 miles | | Length = 0.2 miles | | | |
| R = 0.000720 pu | | R = 0.000180pu | | | |
| X = 0.004360 pu | | X = 0.001050 pu | | | |
| B = 0.000620 pu | | B = 0.000160 pu | | | |
| Main Substation Transformer1 | R = 0.003400 pu | R = 0.003200 pu | R = 0.002124 pu | | | |
| X = 0.084930 pu | X = 0.079940 pu | X = 0.084973 pu | | | |
| Winding MVA = 33 MVA | Winding MVA = 48 MVA | Winding MVA = 102 MVA | | | |
| Rating MVA = 55 MVA | Rating MVA = 75 MVA | Rating MVA = 170 MVA | | | |
| Equivalent Collector Line2 | R = 0.004880 pu | | R = 0.014992 pu | | R = 0.003106 pu | |
| X = 0.003310 pu | | X = 0.027776 pu | | X = 0.003490 pu | |
| B = 0.003500 pu | | B = 0.020481 pu | | B = 0.012851 pu | |
| GSU Transformer1 | Gen Equivalent Qty: 22 | Gen Equivalent Qty: 32 | Gen Equivalent Qty: 16 | Gen Equivalent Qty: 2 | | Gen Equivalent Qty: 25 |
| R = 0.008400 pu | R = 0.008400 pu | R = 0.0070448 pu | R = 0.0075994 pu | | R = 0.008697 pu |
| X = 0.060000 pu | X = 0.060000 pu | X = 0.071153 pu | X = 0.056996 pu | | X = 0.089579 pu |
| Winding MVA = 57.2 MVA | Winding MVA = 83.2 MVA | Winding MVA = 59.152 MVA | Winding MVA = 5.6 MVA | | Winding MVA = 105.175 MVA |
| Rating MVA = 57.2 MVA | Rating MVA = 83.2 MVA | Rating MVA = 60.976 MVA | Rating MVA = 6.5 MVA | | Rating MVA = 105.175 MVA |
| Generator Dynamic Model3 and Power Factor | REGCA13 Leading and Lagging: ±0.90 | | GEWTG07053  Leading and Lagging: ±0.9 | GEWTG07053  Leading and Lagging: ±0.90 | | REGCAU13  Leading and Lagging: ±0.88 |
| Reactive Power Devices | N/A | | N/A | | | |
| 1) X/R based on Winding MVA, 2) All pu are on 100 MVA Base 3) DYR stability model name | | | | | | |

SPP determined that powerflow should not be performed because the request was originally studied under all necessary powerflow cases. However, SPP determined that the change in inverter manufacturer from General Electric to Power Electronics required short circuit and dynamic stability analyses.

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

SPP performed the analyses using the modification request data based on the DISIS-2017-002 study models:

1. 2025 Summer Peak (25SP),
2. 2025 Winter Peak (25WP)

All analyses were performed using the Siemens PTI PSS/E[[1]](#footnote-1) version 34 software and the results are summarized below.

The results of the charging current compensation analysis using the 25SP models showed that the GEN-2013-002 and GEN-2013-019 project needed a 1.0 MVAr shunt reactor on the 34.5 kV bus of the project substation with the modifications in place. This is necessary to offset the capacitive effect on the transmission network caused by the project’s transmission line and collector system during reduced generation 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 short circuit analysis was performed using the 25SP stability model modified for short circuit analysis. The results from the short circuit analysis with the updated topology showed that the maximum GEN-2013-002 and GEN-2013-019 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2013-002 and GEN-2013-019 POI was no greater than 0.772 kA. There were multiple buses with a maximum three-phase fault current over 40 kA. These buses are highlighted in Appendix B.

The dynamic stability analysis was performed using Siemens PTI PSS/E version 34.8.0 software for the two modified study models: 25SP and 25WP. Eighty-seven events were simulated, which included three-phase faults and single-line-to-ground stuck breaker faults.

The results of the dynamic stability analysis showed that there were multiple existing base case issues found in the original DISIS-2017-002 case and the case with the GEN-2013-002 and GEN-2013-019 modification. These issues were not attributed to the GEN-2013-002 and GEN-2013-019 modification request and detailed in Appendix D.

There were no damping or voltage recovery violations attributed to the GEN-2013-002 and GEN-2013-019 modification request 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.

# Scope of Study

Southwest Power Pool (SPP) performed a Modification Request Impact Study (Study) for GEN-2013-002 and GEN-2013-019. 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 Siemens PTI PSS/E version 34 software. The results of each analysis are presented in the following sections.

## Powerflow Analysis

SPP determined that powerflow should not be performed because the request was originally studied under all necessary powerflow cases.

## Stability Analysis, Short Circuit Analysis

To determine whether stability and short circuit analyses are required, SPP evaluates the difference between the stability model parameters and, if needed, the equivalent 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.

## 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.

## Study Limitations

The assessments and conclusions provided in this report are based on assumptions and information provided to SPP by others. While the assumptions and information provided may be appropriate for the purposes of this report, SPP does not guarantee that those conditions assumed will occur. In addition, SPP 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.

# Project and Modification Request

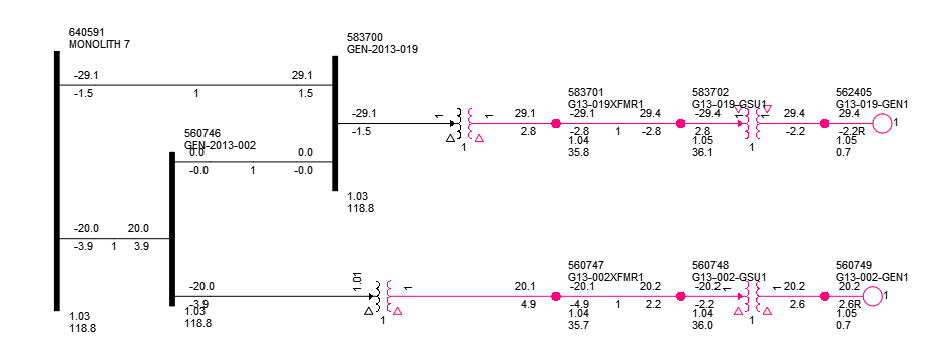
The GEN-2013-002 and GEN-2013-019 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a Point of Interconnection (POI) at the Monolith 115kV Substation. At the time of report posting, GEN-2013-002 and GEN-2013-019 is an active Interconnection Request with a queue status of “IA FULLY EXECUTED/ON SCHEDULE.” GEN-2013-002 and GEN-2013-019 is a solar plant with a maximum summer and winter queue capacity of 30 MW with Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS).

The GEN-2013-002 and GEN-2013-019 project is currently in the DISIS-2017-001 cluster. Figure 2‑1 shows the powerflow model single line diagram for the existing GEN-2013-002 and GEN-2013-019 configuration using the DISIS-2017-002 stability models. The GEN-2013-002 and GEN-2013-019 project interconnects in the Nebraska Public Power District (NPPD) control area with a capacity of 124.2 MW as shown in Table 2‑1 below.

Table 2‑1: GEN-2013-002 and GEN-2013-019 Existing Configuration

|  |  |  |  |
| --- | --- | --- | --- |
| Request | Point of Interconnection | Existing Generator Configuration | GIA Capacity (MW) |
| GEN-2013-002 and GEN-2013-019 | Monolith 115 kV Substation (640591) | 22 x GE 2.3 MW  32 x GE 2.3 MW | 124.2 |

Figure 2‑1: GEN-2013-002 and GEN-2013-019 Single Line Diagram (Existing Configuration\*)



\*based on the DISIS-2017-002 stability models

This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2013-002 and GEN-2013-019 to a configuration of 16 x GE 3.4 MW wind turbines (GEWTG0705), 2 x GE 2.82 MW wind turbines (GEWTG0705), and 25 x Power Electronics 4.01 MVA solar inverters (REGCAU1) for a total capacity of 148.26 MW. This generating capacity for GEN-2013-002 and GEN-2013-019 (148.26 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 124.2 MW, as listed in Appendix A of the GIA. As a result, the customer must ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

In addition, the modification request included changes to the collection system, generator step-up transformer, generation interconnection line, main substation transformer, and reactive power devices. Figure 2‑2 shows the powerflow model single line diagram for the GEN-2013-002 and GEN-2013-019 modification. The existing and modified configurations for GEN-2013-002 and GEN-2013-019 are shown in Table 2‑2.

Figure 2‑2: GEN-2013-002 and GEN-2013-019 Single Line Diagram (Modification Configuration)

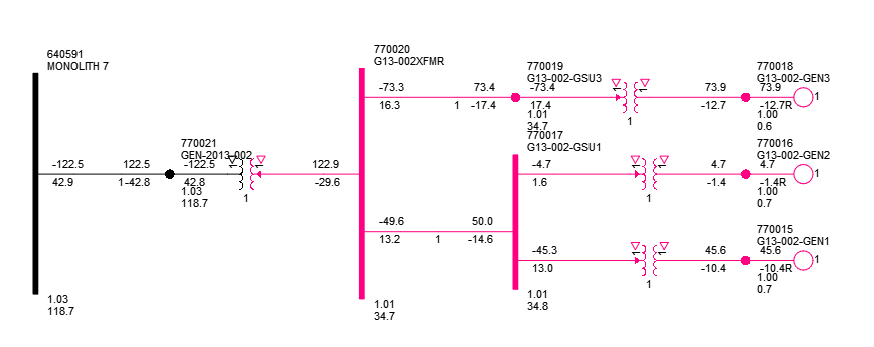


Table 2‑2: GEN-2013-002 and GEN-2013-019 Modification Request

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| Facility | Existing Generating Facility Configuration | | Modification Generating Facility Configuration | | | |
| Point of Interconnection | Monolith 115 kV Substation (640591) | | Monolith 115 kV Substation (640591) | | | |
| Configuration/Capacity | 22 x GE 2.3 MW Wind Turbines = 50.6MW 32 x GE 2.3MW Wind Turbines = 73.6MW | | 16 x GE 3.4 MW Wind Turbines = 54.4MW 2 x GE 2.82 MW Wind Turbines = 5.64 25 x PE 4.01 MVA Solar Inverters = 88.22MW ***POI Injection limited to 124.2 MW*** | | | |
| Generation Interconnection Line | Length = 0.8 miles | | Length = 0.2 miles | | | |
| R = 0.000720 pu | | R = 0.000180pu | | | |
| X = 0.004360 pu | | X = 0.001050 pu | | | |
| B = 0.000620 pu | | B = 0.000160 pu | | | |
| Main Substation Transformer1 | R = 0.003400 pu | R = 0.003200 pu | R = 0.002124 pu | | | |
| X = 0.084930 pu | X = 0.079940 pu | X = 0.084973 pu | | | |
| Winding MVA = 33 MVA | Winding MVA = 48 MVA | Winding MVA = 102 MVA | | | |
| Rating MVA = 55 MVA | Rating MVA = 75 MVA | Rating MVA = 170 MVA | | | |
| Equivalent Collector Line2 | R = 0.004880 pu | | R = 0.014992 pu | | R = 0.003106 pu | |
| X = 0.003310 pu | | X = 0.027776 pu | | X = 0.003490 pu | |
| B = 0.003500 pu | | B = 0.020481 pu | | B = 0.012851 pu | |
| GSU Transformer1 | Gen Equivalent Qty: 22 | Gen Equivalent Qty: 32 | Gen Equivalent Qty: 16 | Gen Equivalent Qty: 2 | | Gen Equivalent Qty: 25 |
| R = 0.008400 pu | R = 0.008400 pu | R = 0.0070448 pu | R = 0.0075994 pu | | R = 0.008697 pu |
| X = 0.060000 pu | X = 0.060000 pu | X = 0.071153 pu | X = 0.056996 pu | | X = 0.089579 pu |
| Winding MVA = 57.2 MVA | Winding MVA = 83.2 MVA | Winding MVA = 59.152 MVA | Winding MVA = 5.6 MVA | | Winding MVA = 105.175 MVA |
| Rating MVA = 57.2 MVA | Rating MVA = 83.2 MVA | Rating MVA = 60.976 MVA | Rating MVA = 6.5 MVA | | Rating MVA = 105.175 MVA |
| Generator Dynamic Model3 and Power Factor | REGCA13 Leading and Lagging: ±0.90 | | GEWTG07053  Leading and Lagging: ±0.9 | GEWTG07053  Leading and Lagging: ±0.90 | | REGCAU13  Leading and Lagging: ±0.88 |
| Reactive Power Devices | N/A | | N/A | | | |
| 1) X/R based on Winding MVA, 2) All pu are on 100 MVA Base 3) DYR stability model name | | | | | | |

# Existing Versus Modification Comparison

To determine which analyses are required for the Study, the differences between the existing configuration and the requested modification were evaluated. SPP performed this comparison and the resulting analyses using a set of modified study models developed based on the modification request data and the DISIS-2017-002 study models.

The methodology and results of the comparisons are described below. The analysis was completed using PSS/E version 34 software.

## Stability Model Parameters Comparison

SPP determined that short circuit and dynamic stability analyses were required because of the inverter change from General Electric to Power Electronic. 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.

## Equivalent Impedance Comparison Calculation

As the inverter 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.

# Charging Current Compensation Analysis

The charging current compensation analysis was performed for GEN-2013-002 and GEN-2013-019 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.

## Methodology and Criteria

The GEN-2013-002 and GEN-2013-019 generators and capacitors were switched out of service while other 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).

SPP performed the charging current compensation analysis using the modification request data based on the 2025 Summer Peak (25SP) DISIS-2017-002 stability study models.

## Results

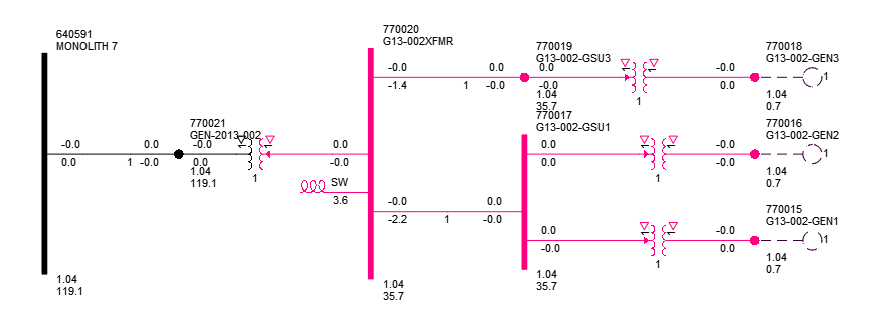
The results from the analysis showed that the GEN-2013-002 and GEN-2013-019 project needed approximately 3.5 MVAr of compensation at its project substation to reduce the POI MVAr to zero. Figure 4‑1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the updated topology. The final shunt reactor requirements for GEN-2013-002 and GEN-2013-019 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 Reduced Generation Study (Modification)

| Machine | POI Bus Number | POI Bus Name | Reactor Size (MVAr) |
| --- | --- | --- | --- |
| 25SP |
| GEN-2013-002 and  GEN-2013-019 | 640591 | Monolith 115 kV | 3.5 |

Figure 4‑1: GEN-2013-002 and GEN-2013-019 Single Line Diagram w/ Charging Current Compensation (Modification)



# Short Circuit Analysis

A short circuit study was performed using the 25SP model for GEN-2013-002 and GEN-2013-019. The detailed results of the short circuit analysis are provided in Appendix B.

## Methodology

The short circuit analysis included applying a three-phase fault on buses up to 5 levels away from the 115 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-2013-002 and GEN-2013-019 online.

SPP created a short circuit model using the 25SP DISIS-2017-002 stability study model by adjusting the GEN-2013-002 and GEN-2013-019 short circuit parameters consistent with the modification data. The adjusted parameters are shown in Table 5‑1 below.

Table 5‑1: Short Circuit Model Parameters\*

|  |  |  |  |
| --- | --- | --- | --- |
| Parameter | Value by Generator Bus# | | |
| **770015** | **770016** | **770018** |
| Machine MVA Base | 60.45 | 6.27 | 100.25 |
| R (pu) | 0.0 | 0.0 | 0.0 |
| X’’ (pu) | 0.8 | 0.8 | 0.893 |

\*pu values based on Machine MVA Base

## Results

The results of the short circuit analysis for the 25SP model are summarized in Table 5‑2 and Table 5‑3. The GEN-2013-002 and GEN-2013-019 POI bus (Monolith 115kV - 640591) fault current magnitudes are provided in Table 5‑2 showing a maximum fault current of 42.033 kA with the GEN-2013-002 and GEN-2013-019 project online. Table 5‑3 shows the maximum fault current magnitudes and fault current increases with the GEN-2013-002 and GEN-2013-019 project online.

There were several buses with a maximum three-phase fault current over 40 kA. These buses are highlighted in Appendix B. The maximum GEN-2013-002 and GEN-2013-019 contribution to three-phase fault current was about 1.87% and 0.772 kA.

Table 5‑2: POI Short Circuit Results

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Case | GEN-OFF Current (kA) | GEN-ON Current (kA) | Max kA Change | Max %Change |
| 25SP | 41.261 | 42.033 | 0.772 | 1.87% |

Table 5‑3: 25SP Short Circuit Results

|  |  |  |  |
| --- | --- | --- | --- |
| Voltage (kV) | Max. Current (kA) | Max kA Change | Max %Change |
| 69 | 5.512 | 0.003 | 0.05% |
| 115 | 43.305 | 0.772 | 1.87% |
| 161 | 42.569 | 0.01 | 0.02% |
| 230 | 16.633 | 0.007 | 0.04% |
| 345 | 32.735 | 0.147 | 0.66% |
| **Max** | **43.305** | **0.772** | **1.87%** |

# Dynamic Stability Analysis

SPP performed a dynamic stability analysis to identify the impact of the inverter configuration change and other modifications to GEN-2013-002 and GEN-2013-019. The analysis was performed according to SPP’s Disturbance Performance Requirements[[2]](#footnote-2). The modification details are described in the Project and Modification Request section and the dynamic modeling data is provided in Appendix A. The existing base case issues and simulation plots can be found in Appendix C.

## Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested GEN-2013-002 and GEN-2013-019 configuration of 16 x GE 3.4 MW wind turbines (GEWTG0705), 2 x GE 2.82 MW wind turbines (GEWTG0705), and 25 x Power Electronics 4.01 MVA solar inverters (REGCAU1). This stability analysis was performed using PTI’s PSS/E version 34.8.0 software.

The modifications requested for the GEN-2013-002 and GEN-2013-019 project were used to create modified stability modelsfor this impact study based on the DISIS-2017-002 stability study models:

1. 2025 Summer Peak (25SP),
2. 2025 Winter Peak (25WP)

The modified dynamic model data for the GEN-2013-002 and GEN-2013-019 project is provided in Appendix A. The modified powerflow models and associated dynamic database were initialized (no-fault test) to confirm that there were no errors in the initial conditions of the system and the dynamic data.

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

1. Updated Grand Prairie powerflow and dynamic models to 2022 MDAG.
2. Disabled voltage relays at 635020, 541514, 541549, 541546, 541550, 800103, and 585248 to avoid generator tripping
3. Disabled frequency relay at 585248 to avoid generator tripping
4. Disabled line relay for 602057 – 667085 CKT 1 to avoid line tripping
5. Disabled loss of excitation relay (LOEXR1T) for machine at 541171

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2013-002 and GEN-2013-019 and other current and prior queued projects in their cluster group[[3]](#footnote-3). In addition, voltages of five (5) buses away from the POI of GEN-2013-002 and GEN-2013-019 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas including 531 (MIDW), 534 (SUNC), 536 (WERE), 640 (NPPD), 641 (HAST), 642 (GRIS), 645 (OPPD), 650 (LES), 652 (WAPA), and 659 (BEPC) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

## Fault Definitions

SPP simulated the faults previously simulated for GEN-2013-002 and GEN-2013-019 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. Single-line-to-ground faults are approximated by applying a fault impedance to bring the faulted bus positive sequence voltage to 0.6 pu. The simulated faults are listed and described in Table 6‑1 below. These contingencies were applied to the modified 25SP and 25WP models.

Table 6‑1: Fault Definitions

| Fault ID | Planning Event | Fault Descriptions |
| --- | --- | --- |
| FLT9001-3PH | P1 | 3 phase fault on the S3455 3 (645455) to S3761 3 (645761) 345 kV line CKT 1, near S3455 3. a. Apply fault at the S3455 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9002-3PH | P1 | 3 phase fault on the S3455 3 345kV (645455)/ 161 kV (646255)/ 13.8 kV (648355) XFMR CKT 1, near S3455 3 345 kV. a. Apply fault at the S3455 3 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9003-3PH | P1 | 3 phase fault on the S1255 5 (646255) to S1361 5 (646361) 345 kV line CKT 1, near S1255 5. a. Apply fault at the S1255 5 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9005-3PH | P1 | 3 phase fault on the S3761 3 161kV (645761)/ 161 kV (646361)/ 13.8 kV (648261) XFMR CKT 1, near S3761 3 161 kV. a. Apply fault at the S3761 3 161 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9006-3PH | P1 | 3 phase fault on the MONOLITH 3 (640590) to COOPER 3 (640139) 345 kV line CKT 1, near MONOLITH 3. a. Apply fault at the MONOLITH 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9007-3PH | P1 | 3 phase fault on the COOPER 3 (640139) to ATCHSN 3 (635017) 345 kV line CKT 1, near COOPER 3. a. Apply fault at the COOPER 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9008-3PH | P1 | 3 phase fault on the COOPER 3 345kV (640139)/ 161 kV (640140)/ 13.8 kV (643172) XFMR CKT 1, near COOPER 3 345 kV. a. Apply fault at the COOPER 3 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9009-3PH | P1 | 3 phase fault on the COOPER 3 345kV (640139)/ 161 kV (640140)/ 13.8 kV (640142) XFMR CKT 1, near COOPER 3 345 kV. a. Apply fault at the COOPER 3 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9010-3PH | P1 | 3 phase fault on the COOPER 3 (640139) to 7FAIRPT (300039) 345 kV line CKT 1, near COOPER 3. a. Apply fault at the COOPER 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9011-3PH | P1 | 3 phase fault on the COOPER 3 (640139) to ST JOE 7 (541199) 345 kV line CKT 1, near COOPER 3. a. Apply fault at the COOPER 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9012-3PH | P1 | 3 phase fault on the ST JOE 7 (541199) to 7FAIRPT (300039) 345 kV line CKT 1, near ST JOE 7. a. Apply fault at the ST JOE 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9013-3PH | P1 | 3 phase fault on the 7FAIRPT 345kV (300039)/ 161 kV (301559) XFMR CKT 1, near 7FAIRPT 345 kV. a. Apply fault at the 7FAIRPT 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9014-3PH | P1 | 3 phase fault on the COOPER 5 (640140) to S1280 5 (646280) 161 kV line CKT 1, near COOPER 5. a. Apply fault at the COOPER 5 161 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9015-3PH | P1 | 3 phase fault on the COOPER 5 161kV (640140)/ 69 kV (640446)/ 13.8 kV (643173) XFMR CKT 1, near COOPER 5 161 kV. a. Apply fault at the COOPER 5 161 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9016-3PH | P1 | 3 phase fault on the ATCHSN 3 (635017) to ORIENT 3 (635570) 345 kV line CKT 1, near ATCHSN 3. a. Apply fault at the ATCHSN 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9017-3PH | P1 | 3 phase fault on the ORIENT 3 (635570) to BOONVIL3 (635630) 345 kV line CKT 1, near ORIENT 3. a. Apply fault at the ORIENT 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9018-3PH | P1 | 3 phase fault on the ORIENT 3 (635570) to MADISON3 (635635) 345 kV line CKT 1, near ORIENT 3. a. Apply fault at the ORIENT 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9019-3PH | P1 | 3 phase fault on the ORIENT 3 (635570) to RLHILLS3 (635100) 345 kV line CKT 1, near ORIENT 3. a. Apply fault at the ORIENT 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9020-3PH | P1 | 3 phase fault on the NW68HOLDRG7 (650214) to NW70FAIRFD7 (650210) 115 kV line CKT 1, near NW68HOLDRG7. a. Apply fault at the NW68HOLDRG7 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9021-3PH | P1 | 3 phase fault on the NW68HOLDRG7 (650214) to PAWNEEL7 (640316) 115 kV line CKT 1, near NW68HOLDRG7. a. Apply fault at the NW68HOLDRG7 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9022-3PH | P1 | 3 phase fault on the NW70FAIRFD7 (650210) to NW56&MORTN7 (650207) 115 kV line CKT 1, near NW70FAIRFD7. a. Apply fault at the NW70FAIRFD7 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9023-3PH | P1 | 3 phase fault on the NW68HOLDRG7 (650214) to SW27&F 7 (650216) 115 kV line CKT 1, near NW68HOLDRG7. a. Apply fault at the NW68HOLDRG7 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9024-3PH | P1 | 3 phase fault on the S3455 3 (645455) to S3761 3 (645761) 345 kV line CKT 1, near S3455 3. a. Apply fault at the S3455 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9025-3PH | P1 | 3 phase fault on the S3455 3 345kV (645455)/ 161 kV (646255)/ 13.8 kV (648355) XFMR CKT 1, near S3455 3 345 kV. a. Apply fault at the S3455 3 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9026-3PH | P1 | 3 phase fault on the S1255 5 (646255) to S1361 5 (646361) 345 kV line CKT 1, near S1255 5. a. Apply fault at the S1255 5 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9027-3PH | P1 | 3 phase fault on the S3761 3 161kV (645761)/ 161 kV (646361)/ 13.8 kV (648261) XFMR CKT 1, near S3761 3 161 kV. a. Apply fault at the S3761 3 161 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9028-3PH | P1 | 3 phase fault on the MONOLITH 3 (640590) to COOPER 3 (640139) 345 kV line CKT 1, near MONOLITH 3. a. Apply fault at the MONOLITH 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9029-3PH | P1 | 3 phase fault on the COOPER 3 (640139) to ATCHSN 3 (635017) 345 kV line CKT 1, near COOPER 3. a. Apply fault at the COOPER 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9030-3PH | P1 | 3 phase fault on the COOPER 3 345kV (640139)/ 161 kV (640140)/ 13.8 kV (643172) XFMR CKT 1, near COOPER 3 345 kV. a. Apply fault at the COOPER 3 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9031-3PH | P1 | 3 phase fault on the COOPER 3 345kV (640139)/ 161 kV (640140)/ 13.8 kV (640142) XFMR CKT 1, near COOPER 3 345 kV. a. Apply fault at the COOPER 3 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9032-3PH | P1 | 3 phase fault on the COOPER 3 (640139) to 7FAIRPT (300039) 345 kV line CKT 1, near COOPER 3. a. Apply fault at the COOPER 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9033-3PH | P1 | 3 phase fault on the COOPER 3 (640139) to ST JOE 7 (541199) 345 kV line CKT 1, near COOPER 3. a. Apply fault at the COOPER 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9034-3PH | P1 | 3 phase fault on the ST JOE 7 (541199) to 7FAIRPT (300039) 345 kV line CKT 1, near ST JOE 7. a. Apply fault at the ST JOE 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9035-3PH | P1 | 3 phase fault on the 7FAIRPT 345kV (300039)/ 161 kV (301559) XFMR CKT 1, near 7FAIRPT 345 kV. a. Apply fault at the 7FAIRPT 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9036-3PH | P1 | 3 phase fault on the COOPER 5 (640140) to S1280 5 (646280) 161 kV line CKT 1, near COOPER 5. a. Apply fault at the COOPER 5 161 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9037-3PH | P1 | 3 phase fault on the COOPER 5 161kV (640140)/ 69 kV (640446)/ 13.8 kV (643173) XFMR CKT 1, near COOPER 5 161 kV. a. Apply fault at the COOPER 5 161 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9038-3PH | P1 | 3 phase fault on the ATCHSN 3 (635017) to ORIENT 3 (635570) 345 kV line CKT 1, near ATCHSN 3. a. Apply fault at the ATCHSN 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9039-3PH | P1 | 3 phase fault on the ORIENT 3 (635570) to BOONVIL3 (635630) 345 kV line CKT 1, near ORIENT 3. a. Apply fault at the ORIENT 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9040-3PH | P1 | 3 phase fault on the ORIENT 3 (635570) to MADISON3 (635635) 345 kV line CKT 1, near ORIENT 3. a. Apply fault at the ORIENT 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9041-3PH | P1 | 3 phase fault on the ORIENT 3 (635570) to RLHILLS3 (635100) 345 kV line CKT 1, near ORIENT 3. a. Apply fault at the ORIENT 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9042-3PH | P1 | 3 phase fault on the NW68HOLDRG7 (650214) to NW70FAIRFD7 (650210) 115 kV line CKT 1, near NW68HOLDRG7. a. Apply fault at the NW68HOLDRG7 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9043-3PH | P1 | 3 phase fault on the NW68HOLDRG7 (650214) to PAWNEEL7 (640316) 115 kV line CKT 1, near NW68HOLDRG7. a. Apply fault at the NW68HOLDRG7 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9044-3PH | P1 | 3 phase fault on the NW70FAIRFD7 (650210) to NW56&MORTN7 (650207) 115 kV line CKT 1, near NW70FAIRFD7. a. Apply fault at the NW70FAIRFD7 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9045-3PH | P1 | 3 phase fault on the NW68HOLDRG7 (650214) to SW27&F 7 (650216) 115 kV line CKT 1, near NW68HOLDRG7. a. Apply fault at the NW68HOLDRG7 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9046-3PH | P1 | 3 phase fault on the S3455 3 (645455) to S3761 3 (645761) 345 kV line CKT 1, near S3455 3. a. Apply fault at the S3455 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9047-3PH | P1 | 3 phase fault on the S3455 3 345kV (645455)/ 161 kV (646255)/ 13.8 kV (648355) XFMR CKT 1, near S3455 3 345 kV. a. Apply fault at the S3455 3 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9048-3PH | P1 | 3 phase fault on the S1255 5 (646255) to S1361 5 (646361) 345 kV line CKT 1, near S1255 5. a. Apply fault at the S1255 5 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9049-3PH | P1 | 3 phase fault on the S3761 3 161kV (645761)/ 161 kV (646361)/ 13.8 kV (648261) XFMR CKT 1, near S3761 3 161 kV. a. Apply fault at the S3761 3 161 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9050-3PH | P1 | 3 phase fault on the MONOLITH 3 (640590) to COOPER 3 (640139) 345 kV line CKT 1, near MONOLITH 3. a. Apply fault at the MONOLITH 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9051-3PH | P1 | 3 phase fault on the COOPER 3 (640139) to ATCHSN 3 (635017) 345 kV line CKT 1, near COOPER 3. a. Apply fault at the COOPER 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9052-3PH | P1 | 3 phase fault on the COOPER 3 345kV (640139)/ 161 kV (640140)/ 13.8 kV (643172) XFMR CKT 1, near COOPER 3 345 kV. a. Apply fault at the COOPER 3 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9053-3PH | P1 | 3 phase fault on the COOPER 3 345kV (640139)/ 161 kV (640140)/ 13.8 kV (640142) XFMR CKT 1, near COOPER 3 345 kV. a. Apply fault at the COOPER 3 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9054-3PH | P1 | 3 phase fault on the COOPER 3 (640139) to 7FAIRPT (300039) 345 kV line CKT 1, near COOPER 3. a. Apply fault at the COOPER 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9055-3PH | P1 | 3 phase fault on the COOPER 3 (640139) to ST JOE 7 (541199) 345 kV line CKT 1, near COOPER 3. a. Apply fault at the COOPER 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9056-3PH | P1 | 3 phase fault on the ST JOE 7 (541199) to 7FAIRPT (300039) 345 kV line CKT 1, near ST JOE 7. a. Apply fault at the ST JOE 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9057-3PH | P1 | 3 phase fault on the 7FAIRPT 345kV (300039)/ 161 kV (301559) XFMR CKT 1, near 7FAIRPT 345 kV. a. Apply fault at the 7FAIRPT 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9058-3PH | P1 | 3 phase fault on the COOPER 5 (640140) to S1280 5 (646280) 161 kV line CKT 1, near COOPER 5. a. Apply fault at the COOPER 5 161 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9059-3PH | P1 | 3 phase fault on the COOPER 5 161kV (640140)/ 69 kV (640446)/ 13.8 kV (643173) XFMR CKT 1, near COOPER 5 161 kV. a. Apply fault at the COOPER 5 161 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9060-3PH | P1 | 3 phase fault on the ATCHSN 3 (635017) to ORIENT 3 (635570) 345 kV line CKT 1, near ATCHSN 3. a. Apply fault at the ATCHSN 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9061-3PH | P1 | 3 phase fault on the ORIENT 3 (635570) to BOONVIL3 (635630) 345 kV line CKT 1, near ORIENT 3. a. Apply fault at the ORIENT 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9062-3PH | P1 | 3 phase fault on the ORIENT 3 (635570) to MADISON3 (635635) 345 kV line CKT 1, near ORIENT 3. a. Apply fault at the ORIENT 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9063-3PH | P1 | 3 phase fault on the ORIENT 3 (635570) to RLHILLS3 (635100) 345 kV line CKT 1, near ORIENT 3. a. Apply fault at the ORIENT 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9064-3PH | P1 | 3 phase fault on the NW68HOLDRG7 (650214) to NW70FAIRFD7 (650210) 115 kV line CKT 1, near NW68HOLDRG7. a. Apply fault at the NW68HOLDRG7 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9065-3PH | P1 | 3 phase fault on the NW68HOLDRG7 (650214) to PAWNEEL7 (640316) 115 kV line CKT 1, near NW68HOLDRG7. a. Apply fault at the NW68HOLDRG7 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9066-3PH | P1 | 3 phase fault on the NW70FAIRFD7 (650210) to NW56&MORTN7 (650207) 115 kV line CKT 1, near NW70FAIRFD7. a. Apply fault at the NW70FAIRFD7 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9067-3PH | P1 | 3 phase fault on the NW68HOLDRG7 (650214) to SW27&F 7 (650216) 115 kV line CKT 1, near NW68HOLDRG7. a. Apply fault at the NW68HOLDRG7 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9068-3PH | P1 | 3 phase fault on the S3455 3 (645455) to S3761 3 (645761) 345 kV line CKT 1, near S3455 3. a. Apply fault at the S3455 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9069-3PH | P1 | 3 phase fault on the S3455 3 345kV (645455)/ 161 kV (646255)/ 13.8 kV (648355) XFMR CKT 1, near S3455 3 345 kV. a. Apply fault at the S3455 3 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9070-3PH | P1 | 3 phase fault on the S1255 5 (646255) to S1361 5 (646361) 345 kV line CKT 1, near S1255 5. a. Apply fault at the S1255 5 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9071-3PH | P1 | 3 phase fault on the S3761 3 161kV (645761)/ 161 kV (646361)/ 13.8 kV (648261) XFMR CKT 1, near S3761 3 161 kV. a. Apply fault at the S3761 3 161 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9072-3PH | P1 | 3 phase fault on the MONOLITH 3 (640590) to COOPER 3 (640139) 345 kV line CKT 1, near MONOLITH 3. a. Apply fault at the MONOLITH 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9073-3PH | P1 | 3 phase fault on the COOPER 3 (640139) to ATCHSN 3 (635017) 345 kV line CKT 1, near COOPER 3. a. Apply fault at the COOPER 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9074-3PH | P1 | 3 phase fault on the COOPER 3 345kV (640139)/ 161 kV (640140)/ 13.8 kV (643172) XFMR CKT 1, near COOPER 3 345 kV. a. Apply fault at the COOPER 3 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9075-3PH | P1 | 3 phase fault on the COOPER 3 345kV (640139)/ 161 kV (640140)/ 13.8 kV (640142) XFMR CKT 1, near COOPER 3 345 kV. a. Apply fault at the COOPER 3 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9076-3PH | P1 | 3 phase fault on the COOPER 3 (640139) to 7FAIRPT (300039) 345 kV line CKT 1, near COOPER 3. a. Apply fault at the COOPER 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9077-3PH | P1 | 3 phase fault on the COOPER 3 (640139) to ST JOE 7 (541199) 345 kV line CKT 1, near COOPER 3. a. Apply fault at the COOPER 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9078-3PH | P1 | 3 phase fault on the ST JOE 7 (541199) to 7FAIRPT (300039) 345 kV line CKT 1, near ST JOE 7. a. Apply fault at the ST JOE 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9079-3PH | P1 | 3 phase fault on the 7FAIRPT 345kV (300039)/ 161 kV (301559) XFMR CKT 1, near 7FAIRPT 345 kV. a. Apply fault at the 7FAIRPT 345 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9080-3PH | P1 | 3 phase fault on the COOPER 5 (640140) to S1280 5 (646280) 161 kV line CKT 1, near COOPER 5. a. Apply fault at the COOPER 5 161 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9081-3PH | P1 | 3 phase fault on the COOPER 5 161kV (640140)/ 69 kV (640446)/ 13.8 kV (643173) XFMR CKT 1, near COOPER 5 161 kV. a. Apply fault at the COOPER 5 161 kV bus. b. Clear fault after 6 cycles and trip the faulted XFMR. |
| FLT9082-3PH | P1 | 3 phase fault on the ATCHSN 3 (635017) to ORIENT 3 (635570) 345 kV line CKT 1, near ATCHSN 3. a. Apply fault at the ATCHSN 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9083-3PH | P1 | 3 phase fault on the ORIENT 3 (635570) to BOONVIL3 (635630) 345 kV line CKT 1, near ORIENT 3. a. Apply fault at the ORIENT 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9084-3PH | P1 | 3 phase fault on the ORIENT 3 (635570) to MADISON3 (635635) 345 kV line CKT 1, near ORIENT 3. a. Apply fault at the ORIENT 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9085-3PH | P1 | 3 phase fault on the ORIENT 3 (635570) to RLHILLS3 (635100) 345 kV line CKT 1, near ORIENT 3. a. Apply fault at the ORIENT 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9086-3PH | P1 | 3 phase fault on the NW68HOLDRG7 (650214) to NW70FAIRFD7 (650210) 115 kV line CKT 1, near NW68HOLDRG7. a. Apply fault at the NW68HOLDRG7 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9087-3PH | P1 | 3 phase fault on the NW68HOLDRG7 (650214) to PAWNEEL7 (640316) 115 kV line CKT 1, near NW68HOLDRG7. a. Apply fault at the NW68HOLDRG7 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9088-3PH | P1 | 3 phase fault on the NW70FAIRFD7 (650210) to NW56&MORTN7 (650207) 115 kV line CKT 1, near NW70FAIRFD7. a. Apply fault at the NW70FAIRFD7 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT9089-3PH | P1 | 3 phase fault on the NW68HOLDRG7 (650214) to SW27&F 7 (650216) 115 kV line CKT 1, near NW68HOLDRG7. a. Apply fault at the NW68HOLDRG7 115 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault. |
| FLT1001-SLG | P4 | **Stuck Breaker on MONOLITH 7 (640291) 115 kV bus.** a. Apply single-phase fault at MONOLITH 7 (640591) on the 115 kV bus. b. Wait 16 cycles and remove fault.  c. Trip the MONOLITH 7 (640591) to BPS SUB7 (640171) 115 kV line CKT 1 d. Trip the MONOLITH 7 345 kV (640590)/ 115 kV (640591)/ 13.3 kV (640596) XFMR CKT 1. |
| FLT1002-SLG | P4 | **Stuck Breaker on SHELDON7 (640278) 115 kV bus.** a. Apply single-phase fault at SHELDON7 (640278) on the 115 kV bus.. b. Wait 16 cycles and remove fault.  c. Trip the SHELDON7 (640278) to FOLSM&PHIL7 (650242) 115 kV line CKT 1. d. Trip the SHELDON7 (640278) to SW7&BENNET7 (650246) 115 kV line CKT1 |
| FLT1003-SLG | P4 | **Stuck Breaker on FIRTH 7 (640171) 115 kV bus.** a. Apply single-phase fault at FIRTH 7 (640171) on the 115 kV bus. b. Wait 16 cycles and remove fault.  c. Trip the FIRTH 7 (640171) to MONOLITH 7 (640591) 115 kV line CKT 1. d. Trip the FIRTH 7 (640171) to STERLNG7 (640362) 115 kV line CKT 1. |
| FLT1004-SLG | P4 | **Stuck Breaker on MONOLITH 3 (640590) 345 kV bus.** a. Apply single-phase fault at MONOLITH 3 (640590) on the 345 kV bus. b. Wait 16 cycles and remove fault.  c. Trip the MONOLITH 3 (640590) to MOORE 3 (640277) 345 kV line CKT 1. d. Trip the MONOLITH 3 (640590) to COOPER 3 (640139) 345 kV line CKT 1. |
| FLT1005-SLG | P4 | **Stuck Breaker on COOPER 3 (640139) 345 kV bus.** a. Apply single-phase fault at COOPER 3 (640139) on the 345 kV bus.  b. Wait 16 cycles and remove fault.  c. Trip the COOPER 3 (640139) to ST JOE 7 (541199) 345 kV line CKT 1. d. Trip the COOPER 3 (640139) to 7FAIRPT (300039) 345 kV line CKT 2. |
| FLT1006-SLG | P4 | **Stuck Breaker on MOORE 3 (640277) 345 kV bus.** a. Apply single-phase fault at MOORE 3 (640277) on the 345 kV bus.  b. Wait 16 cycles and remove fault.  c. Trip the MOORE 3 (640277) to TOBIAS 3 (640525) 345 kV line CKT 1. d. Trip the MOORE 3 (640277) to MCCOOL 3 (640271) 345 kV line CKT 1. |

## Results

Table 6‑2 shows the relevant results of the fault events simulated for each of the modified cases. Existing DISIS base case issues are documented separately in Appendix D. The associated stability plots are also provided in Appendix D.

Table 6‑2: GEN-2013-002 and GEN-2013-019 Dynamic Stability Results

| Fault ID | 25SP | | | 25WP | | |
| --- | --- | --- | --- | --- | --- | --- |
| Voltage Violation | Voltage Recovery | Stable | Voltage Violation | Voltage Recovery | Stable |
| FLT9001-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9002-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9003-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9005-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9006-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9007-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9008-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9009-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9010-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9011-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9012-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9013-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9014-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9015-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9016-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9017-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9018-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9019-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9020-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9021-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9022-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9023-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9024-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9025-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9026-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9027-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9028-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9029-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9030-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9031-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9032-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9033-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9034-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9035-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9036-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9037-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9038-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9039-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9040-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9041-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9042-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9043-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9044-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9045-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9046-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9047-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9048-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9049-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9050-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9051-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9052-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9053-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9054-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9055-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9056-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9057-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9058-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9059-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9060-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9061-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9062-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9063-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9064-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9065-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9066-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9067-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9068-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9069-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9070-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9072-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9073-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9074-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9075-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9076-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9077-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9078-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9080-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9081-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9087-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9088-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT9089-3PH | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1001-SB | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1002-SB | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1003-SB | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1004-SB | Pass | Pass | Stable | Pass | Pass | Stable |
| FLT1005-SB | Pass | Pass | Stable | Pass | Pass | Stable(1) |
| FLT1006-SB | Pass | Pass | Stable | Pass | Pass | Stable(1) |

The results of the dynamic stability analysis showed that there were multiple existing base case issues found in the original DISIS-2017-002 case and the case with the GEN-2013-002 and GEN-2013-019 modification. These issues were not attributed to the GEN-2013-002 and GEN-2013-019 modification request and detailed in Appendix D.

There were no damping or voltage recovery violations attributed to the GEN-2013-002 and GEN-2013-019 modification request 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.

# Modified Capacity Exceeds GIA Capacity

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

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

## Results

The modified generating capacity of GEN-2013-002 and GEN-2013-019 (148.26 MW) exceeds the GIA Interconnection Service amount, 124.2 MW, as listed in Appendix A of the GIA. The GEN-2013-002 and GEN-2013-019 is assumed to use a Power Plant Controller (PPC) to limit the total power injected into the POI.

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.

# 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.

## Results

SPP determined the requested modification is **not a Material Modification** based on the results of this Modification Request Impact Study performed by SPP. SPP evaluated the impact of the requested modification on the prior study results. SPP determined that the requested modification did not negatively impact the prior study dynamic stability and short circuit results, and the modifications to the project were not enough to change the previously studied powerflow conclusions.

This determination implies that any network upgrades already required by GEN-2013-002 and GEN-2013-019 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.

1. Power System Simulator for Engineering [↑](#footnote-ref-1)
2. [SPP Disturbance Performance Requirements](https://www.spp.org/documents/28859/spp%20disturbance%20performance%20requirements%20(twg%20approved).pdf): https://www.spp.org/documents/28859/spp%20disturbance%20performance%20requirements%20(twg%20approved).pdf [↑](#footnote-ref-2)
3. Based on the DISIS-2017-002 Cluster Groups [↑](#footnote-ref-3)