GEN-2014-035

MODIFICATION REQUEST IMPACT STUDY

By SPP Generator Interconnection

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EXECUTIVE SUMMARY

Southwest Power Pool performed a Modification Request Impact Study (Study) for GEN-2014-035, an active Generation Interconnection Request (GIR) with a Point of Interconnection (POI) at the Chaves County 115 kV Substation.

The GEN-2014-035 project interconnects in the Southwestern Public Service Company (SPS) control area with a capacity of 30 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2014-035 to change the inverter configuration to 8 x PE FS4200M 4.2 MVA for a total capacity of 30.56 MW. The inverters are rated at 3.82 MW, and use a Power Plant Controller (PPC) to limit the total power injected into the POI. The generating capacity for GEN-2014-035 (30MW) and the total capability (30.56MW) exceed its Generator Interconnection Agreement (GIA) Interconnection Service amount, 30 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-2014-035 are shown in Table ES-2.

Table ES-1: GEN-2014-035 Existing Configuration

REQUEST	POINT OF INTERCONNECTION	EXISTING GENERATOR CONFIGURATION	GIA CAPACITY (MW)
GEN-2014-035	Chaves County 115 kV Substation (527482)	8 x PE FS4200M 4.2 MVA Inverters	30

Table ES-2: GEN-2014-035 Modification Request

FACILITY	EXISTING GENERATING FACILITY CONFIGURATION	MODIFICATION GENERATING FACILITY CONFIGURATION
Point of Interconnection	Chaves County 115 kV Substation (527482)	Chaves County 115 kV Substation (527482)
Configuration/Capacity	8 x 4.0 MVA Solar Inverters	8 x PE FS4200M 4.2 MVA Inverters
Generation Interconnection Line	Length = 0.8 miles	Length = 0.45 miles
	R = 0.000720 pu	R = 0.000401 pu
	X = 0.004360 pu	X = 0.002525 pu
	B = 0.000620 pu	B = 0.000340 pu
Main Substation Transformer[1]	R = 0.002670 pu	R = 0.001758 pu
	X = 0.079960 pu	X = 0.080981 pu
	Winding MVA = 18 MVA	Winding MVA = 66 MVA
	Rating MVA = 30 MVA	Rating MVA = 110 MVA
Equivalent Collector Line[2]	R = 0.004880 pu	R = 0.008220 pu
	X = 0.003310 pu	X = 0.004320 pu
	B = 0.003500 pu	B = 0.003298 pu
GSU Transformer[1]	Gen Equivalent Qty: 8	Gen Equivalent Qty: 8
	R = 0.008370 pu	R = 0.006551 pu
	X = 0.059410 pu	X = 0.081236 pu
	Winding MVA = 32 MVA	Winding MVA = 33.6 MVA
	Rating MVA = 32 MVA	Rating MVA = 33.6 MVA
Generator Dynamic Model[3] & Power Factor	REGCAU1[3] Leading and Lagging: ±0.9375	REGCA1[3] Leading and Lagging: ±0.9095
Reactive Power Devices	N/A	3 MVAR Cap Bank
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 technology type of the request was unchanged with the modification. 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] 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-2014-035 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-2014-035 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2014-035 POI was no greater than 0.17 kA. All three-phase fault current levels within 5 buses of the POI with the GEN-2014-035 generator online were below 40 kA.

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. Forty-two 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 several existing base case issues found in the original DISIS-2017-002 case and the case with the GEN-2014-035 modification. These issues were not attributed to the GEN-2014-035 modification request and detailed in Appendix D.

There were no damping or voltage recovery violations attributed to the GEN-2014-035 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

[1] Power System Simulator for Engineering

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-2014-035. 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 technology type of the request was unchanged with the modification.

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

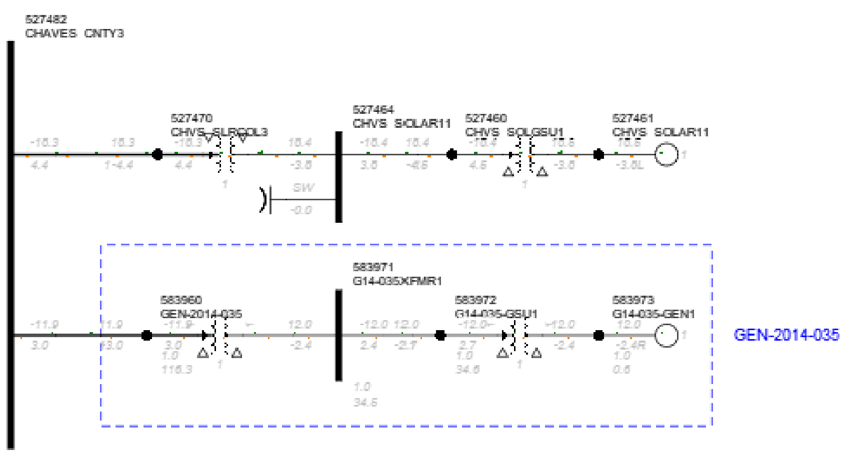
The GEN-2014-035 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a Point of Interconnection (POI) at the Chaves County 115kV Substation. At the time of report posting, GEN-2014-035 is an active Interconnection Request with a queue status of "IA FULLY EXECUTED/ON SCHEDULE." GEN-2014-035 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-2014-035 project is currently in the DISIS-2017-001 cluster. Figure 2-1 shows the powerflow model single line diagram for the existing GEN-2014-035 configuration using the DISIS-2017-002 stability models. The GEN-2014-035 project interconnects in the Southwestern Public Service Company (SPS) control area with a capacity of 30 MW as shown in Table 2-1 below.

Table 2-1: GEN-2014-035 Existing Configuration

REQUEST	POINT OF INTERCONNECTION	EXISTING GENERATOR CONFIGURATION	GIA CAPACITY (MW)
GEN-2014-035	Chaves County 115kV (527482)	Chaves County 115 kV Substation (527482)	30

Figure 2-1: GEN-2014-035 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-2014-035 to an inverter configuration of 8 x PE FS4200M 4.2 MVA Inverters 3.82 MW for a total capacity of 30.56 MW. This generating capacity for GEN-2014-035 (30.56 MW) and the total capability (30.56 MW) exceed its Generator Interconnection Agreement (GIA) Interconnection Service amount, 30 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-2014-035 modification. The existing and modified configurations for GEN-2014-035 are shown in Table 2-2.

Figure 2-2: GEN-2014-035 Single Line Diagram (Modification Configuration)

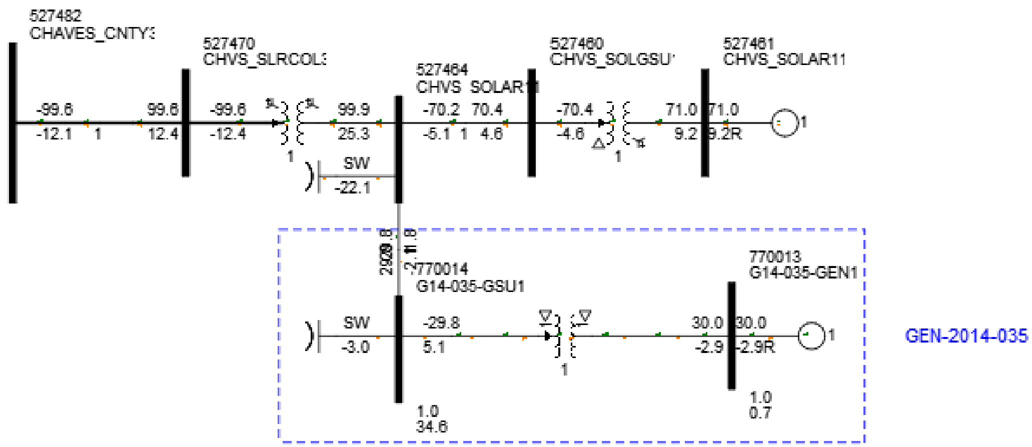


Table 2-2: GEN-2014-035 Modification Request

FACILITY	EXISTING GENERATING FACILITY CONFIGURATION	MODIFICATION GENERATING FACILITY CONFIGURATION
Point of Interconnection	Chaves County 115 kV Substation (527482)	Chaves County 115 kV Substation (527482)
Configuration/Capacity	8 x 4.0 MVA Solar Inverters	8 x PE FS4200M 4.2 MVA Inverters
Generation Interconnection Line	Length = 0.8 miles	Length = 0.45 miles
	R = 0.000720 pu	R = 0.000401 pu
	X = 0.004360 pu	X = 0.002525 pu
	B = 0.000620 pu	B = 0.000340 pu
Main Substation Transformer[1]	R = 0.002670 pu	R = 0.001758 pu
	X = 0.079960 pu	X = 0.080981 pu
	Winding MVA = 18 MVA	Winding MVA = 66 MVA
	Rating MVA = 30 MVA	Rating MVA = 110 MVA
Equivalent Collector Line[2]	R = 0.004880 pu	R = 0.008220 pu
	X = 0.003310 pu	X = 0.004320 pu
	B = 0.003500 pu	B = 0.003298 pu
GSU Transformer[1]	Gen Equivalent Qty: 8	Gen Equivalent Qty: 8
	R = 0.008370 pu	R = 0.006551 pu
	X = 0.059410 pu	X = 0.081236 pu
	Winding MVA = 32 MVA	Winding MVA = 33.6 MVA
	Rating MVA = 32 MVA	Rating MVA = 33.6 MVA
Generator Dynamic Model[3] & Power Factor	REGCAU1[3] Leading and Lagging: ±0.9375	REGCA1[3] Leading and Lagging: ±0.9095
Reactive Power Devices	N/A	3 MVAR Cap Bank
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-2014-035 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-2014-035 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

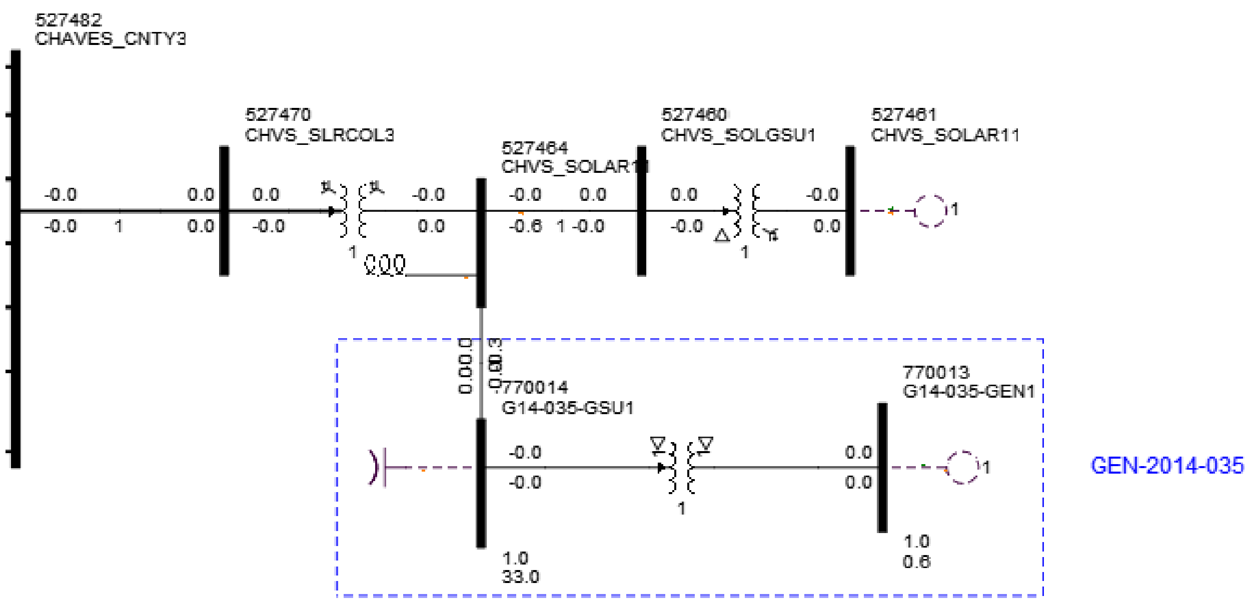
The results from the analysis showed that the GEN-2014-035 project needed approximately 1.0 MVAr of compensation at its project substation to reduce the POI MVAr to zero. Figure 4-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the updated topology. The final shunt reactor requirements for GEN-2014-035 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-2014-035	Chaves County 115kV (527482)	Chaves County 115 kV Substation (527482)	1

Figure 4-1: GEN-2014-035 Single Line Diagram w/ Charging Current Compensation (Modification)



SHORT CIRCUIT ANALYSIS

A short circuit study was performed using the 25SP model for GEN-2014-035. 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-2014-035 online.

SPP created a short circuit model using the 25SP DISIS-2017-002 stability study model by adjusting the GEN-2014-035 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#
	527482
Machine MVA Base	33.6
R (pu)	0.0
X'' (pu)	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-2014-035 POI bus (Chaves County 115kV - 527482) fault current magnitudes are provided in Table 5-2 showing a maximum fault current of 6.66 kA with the GEN-2014-035 project online. Table 5-3 shows the maximum fault current magnitudes and fault current increases with the GEN-2014-035 project online.

The maximum fault current calculated within five buses of the GEN-2014-035 POI (including the POI bus) was less than 40 kA for the 25SP model. The maximum GEN-2014-035 contribution to three-phase fault current was about 2.63% and 0.17 kA.

Table 5-1: POI Short Circuit Results

CASE	GEN-OFF CURRENT (KA)	GEN-ON CURRENT (KA)	MAX KA CHANGE	MAX %CHANGE
25SP	6.49	6.66	0.16	2.53%

Table 5-2: 25SP Short Circuit Results

VOLTAGE (KV)	MAX. CURRENT (KA)	MAX KA CHANGE	MAX %CHANGE
69	3.60	0.03	0.73%
115	27.21	0.17	2.63%
230	27.42	0.07	1.73%
345	11.56	0.02	0.24%
Max	**27.42**	**0.17**	**2.63%**

DYNAMIC STABILITY ANALYSIS

SPP performed a dynamic stability analysis to identify the impact of the inverter configuration change and other modifications to GEN-2014-035. The analysis was performed according to SPP's Disturbance Performance Requirements[2] shown in Appendix C. 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 D.

METHODOLOGY AND CRITERIA

The dynamic stability analysis was performed using models developed with the requested GEN-2014-035 configuration of 8 x PE FS4200M 4.2 MVA Inverters (REGCA1). This stability analysis was performed using PTI's PSS/E version 34.8.0 software.

The modifications requested for the GEN-2014-035 project were used to create modified stability models for 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-2014-035 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 the GEN-2017-198 REGCAU1 dynamic stability model to the latest version.
2. Restored the 2020 MDAG Dempsey generator dynamic stability model.
3. The GEN-2017-176 (761442, 761445, 761447, & 761449) overvoltage protection relays were disabled.
4. The GEN-2014-034 (527461) frequency relay was disabled after observing the generator tripping during initial three phase fault simulations. This frequency tripping issue is a known PSS/E limitation when calculating bus frequency as it relates to non-conventional type devices.

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[2] SPP Disturbance Performance Requirements: https://www.spp.org/documents/28859/spp%20disturbance%20performance%20requirements%20(twg%20approved).pdf

5. GNET small in-group units missing dynamic data (523164, 523167, 523252, 523254, 523297, 523328, 523330, and 523921).
6. Turned shunts at Roosevelt wind to out-of-service.
7. Adjusted winding ratio of Sagamore wind main power transformers.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2014-035 and other current and prior queued projects in their cluster group[3]. In addition, voltages of five (5) buses away from the POI of GEN-2014-035 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas including 330 (AECI), 515 (SWPA), 520 (AEPW), 523 (GRDA), 524 (OKGE), 525 (WFEC), 527 (OMPA), and 534 (SUNC) 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-2014-035 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
FLT9002-3PH	P1	3 phase fault on the ABB 801429 115 kV (527482) / 230 kV (527483)/ 13.2 kV (527478) XFMR CKT 1, near CHAVES_CNTY3 115 kV. a. Apply fault at the CHAVES_CNTY3 115 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9003-3PH	P1	3 phase fault on the CHAVES_CNTY3 (527482) to PRICE TAP 3 (527509) 115 kV line CKT 1, near CHAVES_CNTY3. a. Apply fault at the CHAVES_CNTY3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9004-3PH	P1	3 phase fault on the CHAVES_CNTY3 (527482) to URTON 3 (527501) 115 kV line CKT 1, near CHAVES_CNTY3. a. Apply fault at the CHAVES_CNTY3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line.

[3] Based on the DISIS-2017-002 Cluster Groups

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1	3 phase fault on the CHAVES_CNTY3 (527482) to SAMSON 3 (527546) 115 kV line CKT 1, near CHAVES_CNTY3. a. Apply fault at the CHAVES_CNTY3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9006-3PH	P1	3 phase fault on the CHAVES_CNTY3 (527482) to RSWL_SLRCOL3 (527455) 115 kV line CKT 1, near CHAVES_CNTY3. a. Apply fault at the CHAVES_CNTY3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. **Trip generator GRNSTA_NM2 1 (527453), GRNSTA_NM1 (527452), ROS_SOLGSU11 (527451).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9007-3PH	P1	3 phase fault on the PRICE TAP 3 (527509) to PRICE 3 (527508) 115 kV line CKT 1, near PRICE TAP 3. a. Apply fault at the PRICE TAP 3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	P1	3 phase fault on the PRICE TAP 3 (527509) to CAPITAN 3 (527541) 115 kV line CKT 1, near PRICE TAP 3. a. Apply fault at the PRICE TAP 3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9009-3PH	P1	3 phase fault on the URTON 3 (527501) to ROSWELL_CTY3 (527522) 115 kV line CKT 1, near URTON 3. a. Apply fault at the URTON 3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9010-3PH	P1	3 phase fault on the SAMSON 3 (527546) to ROSWLL_INT 3 (527564) 115 kV line CKT 1, near SAMSON 3. a. Apply fault at the SAMSON 3 (527546) 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9011-3PH	P1	3 phase fault on the CAPITAN 3 (527541) to ROSWLL_INT 3 (527564) 115 kV line CKT 1, near CAPITAN 3. a. Apply fault at the CAPITAN 3 115 kV bus.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9012-3PH	P1	3 phase fault on the ROSWELL_CTY3 (527522) to SW4J795_W 3 (527534) 115 kV line CKT 1, near ROSWELL_CTY3. a. Apply fault at the ROSWELL_CTY3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9013-3PH	P1	3 phase fault on the ROSWLL_INT 3 (527564) to SW4J795_E 3 (527533) 115 kV line CKT 1, near ROSWLL_INT 3. a. Apply fault at the ROSWLL_INT 3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9014-3PH	P1	3 phase fault on the ROSWLL_INT 3 (527564) to SW4J795_W 3 (527534) 115 kV line CKT 1, near ROSWLL_INT 3. a. Apply fault at the ROSWLL_INT 3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9015-3PH	P1	3 phase fault on the AC 017772 138 kV (527564) / 269 kV (527563)/ 13.2 kV (527561) XFMR CKT 1, near ROSWLL_INT 3 115 kV. a. Apply fault at the ROSWLL_INT 3 115 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9016-3PH	P1	3 phase fault on the ROSWLL_INT 3 (527564) to TWEEDY 3 (527597) 115 kV line CKT 1, near ROSWLL_INT 3. a. Apply fault at the ROSWLL_INT 3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9017-3PH	P1	3 phase fault on the ROSWLL_INT 3 (527564) to CAPITAN 3 (527541) 115 kV line CKT 1, near ROSWLL_INT 3. a. Apply fault at the ROSWLL_INT 3 115 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9018-3PH	P1	3 phase fault on the CHAVES_CNTY6 (527483) to SN_JUAN_TAP6 (524885) 230 kV line CKT 1, near CHAVES_CNTY6. a. Apply fault at the CHAVES_CNTY6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
		c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9019-3PH	P1	3 phase fault on the CHAVES_CNTY6 (527483) to EDDY_NORTH 6 (527799) 230 kV line CKT 1, near CHAVES_CNTY6. a. Apply fault at the CHAVES_CNTY6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9020-3PH	P1	3 phase fault on the SN_JUAN_TAP6 (524885) to OASIS 6 (524875) 230 kV line CKT 1, near SN_JUAN_TAP6. a. Apply fault at the SN_JUAN_TAP6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9021-3PH	P1	3 phase fault on the SN_JUAN_TAP6 (524885) to SN_JUAN_WND6 (524889) 230 kV line CKT 1, near SN_JUAN_TAP6. a. Apply fault at the SN_JUAN_TAP6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. **Trip generator SNJN-WTG21 1 (524896), SNJN-WTGA1 1 (524890)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9022-3PH	P1	3 phase fault on the ABB LLM60041 230 kV (524875) / 115 kV (524874)/ 13.2 kV (524872) XFMR CKT 1, near OASIS 230 kV. a. Apply fault at the OASIS 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9023-3PH	P1	3 phase fault on the OASIS 6 (524875) to ROOSEVELT 6 (524909) 230 kV line CKT 1, near OASIS 6. a. Apply fault at the OASIS 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9024-3PH	P1	3 phase fault on the OASIS 6 (524875) to G17-116-TAP (761467) 230 kV line CKT 1, near OASIS 6. a. Apply fault at the OASIS 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9025-3PH	P1	3 phase fault on the HYO 10035628 230 kV (527799) / 115 kV (527798)/ 13.2 kV (527797) XFMR CKT 1, near EDDY_NORTH 230 kV. a. Apply fault at the EDDY_NORTH 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
FLT9026-3PH	P1	3 phase fault on the ABB MNL57141 230 kV (527799) / 18.5 kV (527790) XFMR CKT 1, near EDDY_NORTH 230 kV. a. Apply fault at the EDDY_NORTH 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9027-3PH	P1	3 phase fault on the EDDY_NORTH 6 (527799) to 7-RIVERS 6 (528095) 230 kV line CKT 1, near EDDY_NORTH 6. a. Apply fault at the EDDY_NORTH 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9028-3PH	P1	3 phase fault on the ABB AEM30711 230 kV (527799) / 345 kV (527802)/ 13.2 kV (527796) XFMR CKT 1, near EDDY_NORTH 6 230 kV. a. Apply fault at the EDDY_NORTH 6 230 kV bus. b. Clear fault after 7 cycles and trip the faulted transformer.
FLT9029-3PH	P1	3 phase fault on the EDDY_NORTH 6 (527799) to CUNNIGHM_N 6 (527865) 230 kV line CKT 1, near EDDY_NORTH 6. a. Apply fault at the EDDY_NORTH 6 230 kV bus. b. Clear fault after 7 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
FLT9030-3PH	P1	3 phase fault on the EDDY_CNTY 7 (527802) to CROSSROADS 7 (527656) 345 kV line CKT 1, near EDDY_CNTY 7. a. Apply fault at the EDDY_CNTY 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.
FLT9031-3PH	P1	3 phase fault on the EDDY_CNTY 7 (527802) to KIOWA (527965) 345 kV line CKT 1, near EDDY_CNTY 7. a. Apply fault at the EDDY_CNTY 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.
FLT9032-3PH	P1	3 phase fault on the KIOWA (527965) to RDRUNNER 7 (528027) 345 kV line CKT 1, near KIOWA. a. Apply fault at the KIOWA 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 SPX WT03218 345 kV (527965) /115 kV (527966)/ 13.2 kV (527964) XFMR CKT 1, near KIOWA 345 kV. a. Apply fault at the KIOWA 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
FLT9034-3PH	P1	3 phase fault on the KIOWA (527965) to N_LOVING 7 (528185) 345 kV line CKT 1, near KIOWA. a. Apply fault at the KIOWA 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 KIOWA (527965) to HOBBS_INT 7 (527896) 345 kV line CKT 1, near KIOWA. a. Apply fault at the KIOWA 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.
FLT9037-3PH	P1	3 phase fault on the CROSSROADS 7 (527656) to TOLK 7 (525549) 345 kV line CKT 1, near CROSSROADS 7. a. Apply fault at the CROSSROADS 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.
FLT9038-3PH	P1	3 phase fault on the CROSSROADS 7 (527656) to RSVLT_CC_E 7 (527655) 345 kV line CKT 1, near CROSSROADS 7. a. Apply fault at the CROSSROADS 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip Generator at bus RSVLT_GEN1 1 (527651)** **Trip Generator at bus RSVLT_GEN2 1 (527652)** **Trip Generator at bus MILO_WIND 1 (527653)** 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 CROSSROADS 7 (527656) to SAGA_SCOL 7 (527610) 345 kV line CKT 1, near CROSSROADS 7. a. Apply fault at the CROSSROADS 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip Generator at bus SAGSFT3_2.21 (527605)** **Trip Generator at bus SAGSFT4_2.21 (527607)** **Trip Generator at bus SAGSFT1_2.21 (527614)** **Trip Generator at bus SAGSFT1_2.01 (527615)** **Trip Generator at bus SAGSFT2_2.21 (527617)** **Trip Generator at bus SAGSFT2_2.01 (527618)** 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 CROSSROADS 7 (527656) to GEN-2017-102 (762111) 345 kV line CKT 1, near CROSSROADS 7. a. Apply fault at the CROSSROADS 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip Generator at bus G17-102GEN1 (762114)** 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.

FAULT ID	PLANNING EVENT	FAULT DESCRIPTIONS
FLT1001-SLG	P1	**Stuck Breaker on CHAVES_CNTY6 (527483) 230 kV bus.** a. Apply single-phase fault at CHAVES_CNTY6 (527483) on the 230kV bus. b. Wait 16 cycles and remove fault. c. Trip the CHAVES_CNTY6 (527483) to SN_JUAN_TAP6 (524885) 230 kV line CKT 1. d. Trip the ABB 801429 230 kV (527483)/ 115 kV (527482)/ 13.2 kV (527478) XFMR CKT 1.
FLT1002-SLG	P1	**Stuck Breaker on CHAVES_CNTY6 (527483) 230 kV bus.** a. Apply single-phase fault at CHAVES_CNTY6 (527483) on the 230kV bus. b. Wait 16 cycles and remove fault. c. Trip the CHAVES_CNTY6 (527483) to EDDY_NORTH 6 (527799) 230 kV line CKT 1. d. Trip the ABB 801429 230 kV (527483)/ 115 kV (527482)/ 13.2 kV (527479) XFMR CKT 2.
FLT1003-SLG	P1	**Stuck Breaker on CHAVES_CNTY3 (527482) 115 kV bus.** a. Apply single-phase fault at CHAVES_CNTY3 (527482) on the 230kV bus. b. Wait 16 cycles and remove fault. c. Trip the CHAVES_CNTY3 (527482) to PRICE TAP 3 (527509) 115 kV line CKT 1. d. Trip the CHAVES_CNTY3 (527482) to URTON 3 (527501) 115 kV line CKT 1.
FLT1004-SLG	P1	**Stuck Breaker on CHAVES_CNTY3 (527482) 115 kV bus.** a. Apply single-phase fault at CHAVES_CNTY3 (527482) on the 230kV bus. b. Wait 16 cycles and remove fault. c. Trip the CHAVES_CNTY3 (527482) to SAMSON 3 (527546) 115 kV line CKT 1. d. Trip the ABB 801429 115 kV (527482) / 230 kV (527483)/ 13.2 kV (527479) XFMR CKT 2.

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 6-1: GEN-2014-035 Dynamic Stability Results

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	STABLE
FLT9002-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9003-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9004-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9005-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	STABLE
FLT9006-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9007-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9008-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9009-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9010-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9011-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9012-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9013-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9014-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9015-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9016-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9017-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9018-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9019-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9020-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9021-3PH	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT9022-3PH	Pass	Pass	Stable[1,3]	Pass	Pass	Stable[3]
FLT9023-3PH	Pass	Pass	Stable[1,3]	Pass	Pass	Stable[3]
FLT9024-3PH	Pass	Pass	Stable[1,3]	Pass	Pass	Stable[3]
FLT9025-3PH	Pass	Pass	Stable[1,2,3]	Pass	Pass	Stable[3]

FAULT ID	25SP			25WP		
	VOLT VIOLATION	VOLT RECOVERY	STABLE	VOLT VIOLATION	VOLT RECOVERY	STABLE
FLT9026-3PH	Pass	Pass	Stable[2,3]	Pass	Pass	Stable[3]
FLT9027-3PH	Pass	Pass	Stable[1,2,3]	Pass	Pass	Stable[3]
FLT9028-3PH	Pass	Pass	Stable[2,3]	Pass	Pass	Stable[3]
FLT9029-3PH	Pass	Pass	Stable[2,3]	Pass	Pass	Stable[3]
FLT9030-3PH	Pass	Pass	Stable[1,3]	Pass	Pass	Stable[3]
FLT9031-3PH	Pass	Pass	Stable[1,3]	Pass	Pass	Stable[3]
FLT9032-3PH	Pass	Pass	Stable[1,3]	Pass	Pass	Stable[3]
FLT9033-3PH	Pass	Pass	Stable[1,3]	Pass	Pass	Stable[3]
FLT9034-3PH	Pass	Pass	Stable[1,3]	Pass	Pass	Stable[3]
FLT9035-3PH	Pass	Pass	Stable[1,3]	Pass	Pass	Stable[3]
FLT9037-3PH	Pass	Pass	Stable[1,2,3]	Pass	Pass	Stable[2,3]
FLT9038-3PH	Pass	Pass	Stable[2,3]	Pass	Pass	Stable[2,3]
FLT9039-3PH	Pass	Pass	Stable[1,2,3]	Pass	Pass	Stable[2,3]
FLT9040-3PH	Pass	Pass	Stable[1,2,3]	Pass	Pass	Stable[2,3]
FLT1001-SB	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT1002-SB	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT1003-SB	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]
FLT1004-SB	Pass	Pass	Stable[3]	Pass	Pass	Stable[3]

1) Pre-existing numerical issues cause fault to end before the end of the 20-second interval
2) Pre-existing tripping of Yoakum to Hobbs 345kV circuit was observed during fault
3) Pre-existing synchronous generation power and voltage oscillations during fault

The results of the dynamic stability analysis showed that there were several existing base case issues found in the original DISIS-2017-002 case and the case with the GEN-2014-035 modification. These issues were not attributed to the GEN-2014-035 modification request and detailed in Appendix D.

There were no damping or voltage recovery violations attributed to the GEN-2014-035 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-2014-035 (30 MW) and the total capability (30.56 MW) exceed the GIA Interconnection Service amount, 30 MW, as listed in Appendix A of the GIA. The GEN-2014-035 inverters are rated at 3.82 MW, and 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-2014-035 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.