Report on

GEN-2014-034 Modification Request Impact Study

Revision R1 I December 19, 2022

Submitted to
Southwest Power Pool

SPP Southwest Power Pool

anedenconsulting.com

TABLE OF CONTENTS

Revision History R-1
Executive Summary ES-1
1.0 Scope of Study 1
1.1 Power Flow Analysis 1
1.2 Stability Analysis, Short Circuit Analysis 1
1.3 Charging Current Compensation Analysis 1
1.4 Study Limitations 1
2.0 Project and Modification Request 2
3.0 Existing vs Modification Comparison 4
3.1 POI Injection Comparison 4
3.1 Equivalent Impedance Comparison Calculation 4
3.2 Stability Model Parameters Comparison 5
4.0 Charging Current Compensation Analysis 6
4.1 Methodology and Criteria 6
4.2 Results 6
5.0 Short Circuit Analysis 8
5.1 Methodology 8
5.2 Results 8
6.0 Dynamic Stability Analysis 9
6.1 Methodology and Criteria 9
6.2 Fault Definitions 9
6.3 Results 17
7.0 Modified Capacity Exceeds GIA Capacity 22
7.1 Results 22
8.0 Material Modification Determination 23
8.1 Results 23
9.0 Conclusions 24

LIST OF TABLES

Table ES-1: GEN-2014-034 Existing Configuration ES-1
Table ES-2: GEN-2014-034 Modification Request ES-1
Table 2-1: GEN-2014-034 Existing Configuration 2
Table 2-2: GEN-2014-034 Modification Request 3
Table 3-1: GEN-2014-034 POI Injection Comparison 4
Table 3-2: GEN-2014-034 Impedance Comparison 5
Table 3-3: GEN-2014-034 Impedance Comparison Results 5
Table 4-1: Shunt Reactor Size for Reduced Generation Study (Modification) 6
Table 5-1: POI Short Circuit Results 8
Table 5-2: 25SP Short Circuit Results 8
Table 6-1: Fault Definitions 10
Table 6-2: GEN-2014-034 Dynamic Stability Results 17

LIST OF FIGURES

Figure 2-1: GEN-2014-034 Single Line Diagram (Existing Configuration) 2
Figure 2-2: GEN-2014-034 Single Line Diagram (Modification Configuration) 3
Figure 4-1: GEN-2014-034 Single Line Diagram (Modification) 7
Figure 6-1: FLT9025-3PH Sagamore Units Slow P & Q Recovery (25SP DISIS Case) 19
Figure 6-2: FLT9025-3PH Sagamore Units Slow P & Q Recovery (25SP Modification Case) 20
Figure 6-3: FLT9025-3PH Cunningham Unit 4 Oscillations (25SP DISIS Case) 20
Figure 6-4: FLT9025-3PH Cunningham Unit 4 Oscillations (25SP Modification Case) 21

APPENDICES

APPENDIX A: GEN-2014-034 Generator Dynamic Model
APPENDIX B: Short Circuit Results
APPENDIX C: SPP Disturbance Performance Requirements
APPENDIX D: Dynamic Stability Simulation Plots

Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
12/19/2022	Aneden Consulting	Initial Report Issued

Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2014-034, an active Generation Interconnection Request (GIR) with a point of interconnection (POI) at the Chaves County 115 kV Substation.

The GEN-2014-034 project interconnects in the Southwestern Public Service (SPS) control area with a capacity of 70 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2014-034 to change the main power transformer but keep the existing inverter configuration of 18 x GE 4.0 MW for a total capacity of 72 MW. While the modification request did not include a change in generator configuration, the generating capacity for GEN-2014-034 (72 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 70 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 transformers, and generator power factor. The existing and modified configurations for GEN-2014-034 are shown in Table ES-2.

Table ES-1: GEN-2014-034 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2014-034	Chaves County 115 kV (527482)	18 x GE 4.0 MW = 72 MW POI limited to 70 MW	70

Table ES-2: GEN-2014-034 Modification Request

Facility	Existing Configuration	Modification Configuration
Point of Interconnection	Chaves County 115 kV (527482)	Chaves County 115 kV (527482)
Configuration/Capacity	18 x GE 4.0 MW = 72 MW POI limited to 70 MW	18 x GE 4.0 MW = 72 MW POI limited to 70 MW
Generation Interconnection Line	Length = 0.45 miles R = 0.000401 pu X = 0.002525 pu B = 0.000340 pu Rating MVA = 154 MVA	Length = 0.45 miles R = 0.000401 pu X = 0.002525 pu B = 0.000340 pu Rating MVA = 154 MVA
Main Substation Transformer[1]	X = 8.14%, R = 0.695%, Winding MVA = 48 MVA, Rating MVA = 80 MVA	X = 8.098%, R = 0.176%, Winding MVA = 66 MVA, Rating MVA = 110 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 18 X = 6.789%, R = 0.838%, Winding MVA = 72 MVA, Rating MVA = 72 MVA	Gen 1 Equivalent Qty: 18 X = 6.749%, R = 0.833%, Winding MVA = 72 MVA, Rating MVA = 72 MVA
Equivalent Collector Line[2]	R = 0.004678 pu X = 0.003608 pu B = 0.006730 pu	R = 0.005550 pu X = 0.003624 pu B = 0.006713 pu
Generator Dynamic Model[3] & Power Factor	18 x GE 4.0 MW (REGCAU1)[3] Leading: 1.0 Lagging: 1.0	18 x GE 4.0 MW (REGCAU1)[3] Leading: 0.989 Lagging: 0.989
Reactive Power Devices	2 x 11 MVAr 34.5 kV Capacitor	2 x 11 MVAr 34.5 kV Capacitor

1) X and R based on Winding MVA, 2) All pu are on 100 MVA Base 3) DYR stability model name

SPP determined that power flow should not be performed based on the POI MW injection increase of 1.99% compared to the DISIS-2017-002 power flow models. As the existing and modification configurations kept the same inverter configuration, an equivalent impedance comparison was performed in order to determine the potential impact of the requested change. SPP determined that because the equivalent impedance change of 17.77% was above the 10% threshold, the modification request required dynamic stability and short circuit analyses.

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

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

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

All analyses were performed using the PTI PSS/E version 34 software and the results are summarized below.

The results of the charging current compensation analysis using the 2025 Summer Peak and 2025 Winter Peak models showed that the GEN-2014-034 project needed a 0.7 MVAr shunt reactor on the 34.5 kV bus of the project substation with the modifications in place, a decrease from the 0.88 MVAr found for the previous modification study[1]. 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 model. The results from the short circuit analysis with the updated topology showed that the maximum GEN-2014-034 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2014-034 POI was no greater than 0.31 kA. All three-phase fault current levels within 5 buses of the POI with the GEN-2014-034 generators online were below 32 kA.

The dynamic stability analysis was performed using PTI PSS/E version 34.8 software for the two modified study models: 2025 Summer Peak and 2025 Winter Peak. 66 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults.

The results of the dynamic stability analysis showed that there were several stability base case issues observed in the DISIS-2017-002 case both with and without the GEN-2014-034 modification. These were not attributed to the GEN-2014-034 modification request.

1. The Sagamore generators showed a slow active power (P) and reactive power (Q) recovery under several P1 contingencies which caused voltage recovery violations.

[1] GEN-2014-033, GEN-2014-034, GEN-2014-035 Impact Restudy for Generator Modification (Inverter change), July 2016

2. Oscillations were observed for Cunningham Unit 4 under several P1 contingencies.

The results of the dynamic stability analysis showed that there were no damping or voltage recovery violations attributed to the GEN-2014-034 project observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

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

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

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

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

1.0 Scope of Study

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2014-034. A Modification Request Impact Study is a generation interconnection study performed to evaluate the impacts of modifying the DISIS study assumptions. The determination of the required scope of the study is dependent upon the specific modification requested and how it may impact the results of the DISIS study. Impacting the DISIS results could potentially affect the cost or timing of any Interconnection Request with a later Queue priority date, deeming the requested modification a Material Modification. The criteria sections below include reasoning as to why an analysis was either included or excluded from the scope of study.

All analyses were performed using the PTI PSS/E version 34 software. The results of each analysis are presented in the following sections.

1.1 Power Flow Analysis

To determine whether power flow analysis is required, SPP evaluates the difference in the real power output at the POI between the DISIS-2017-002 power flow configuration and the requested modification. Power flow analysis is performed if the difference in the real power may result in a significant impact on the results of the DISIS power flow analysis.

1.2 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.

1.3 Charging Current Compensation Analysis

SPP requires that a charging current compensation analysis be performed on the requested modification configuration as it is a non-synchronous resource. The charging current compensation analysis determines the capacitive effect at the POI caused by the project's collector system and transmission line's capacitance. A shunt reactor size is determined in order to offset the capacitive effect and maintain zero (0) MVAr flow at the POI while the project's generators and capacitors are offline.

1.4 Study Limitations

The assessments and conclusions provided in this report are based on assumptions and information provided to Aneden by others. While the assumptions and information provided may be appropriate for the purposes of this report, Aneden does not guarantee that those conditions assumed will occur. In addition, Aneden did not independently verify the accuracy or completeness of the information provided. As such, the conclusions and results presented in this report may vary depending on the extent to which actual future conditions differ from the assumptions made or information used herein.

2.0 Project and Modification Request

The GEN-2014-034 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a point of interconnection (POI) at the Chaves County 115 kV Substation.

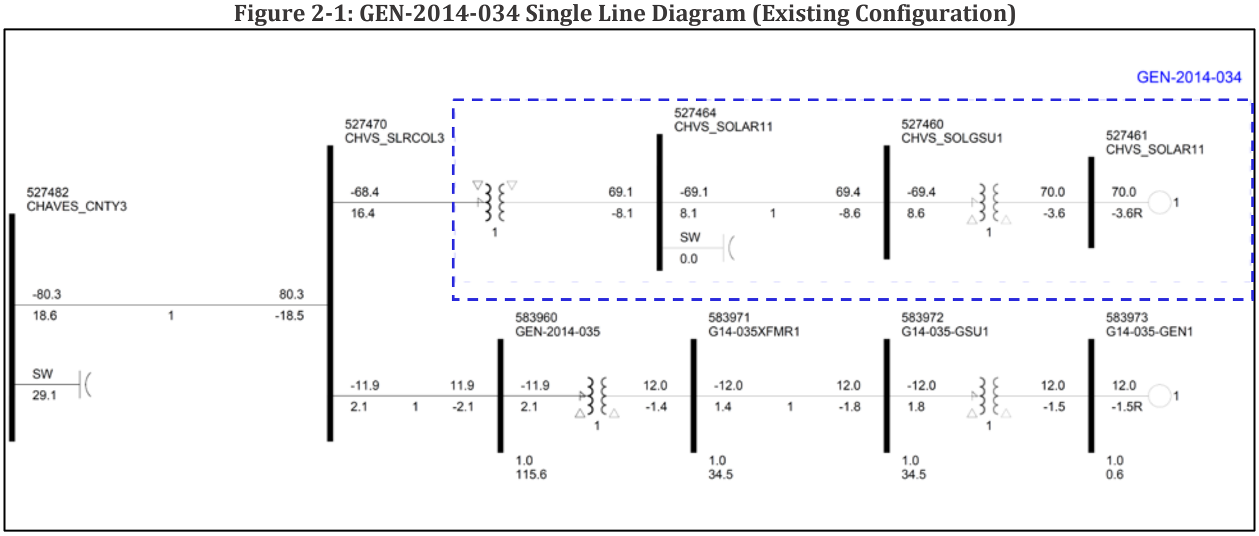
At the time of the posting of this report, GEN-2014-034 is an active Interconnection Request with a queue status of "IA FULLY EXECUTED/ COMMERCIAL OPERATION." GEN-2014-034 is a solar project with a maximum summer and winter queue capacity of 70 MW with Energy Resource Interconnection Service (ERIS).

The GEN-2014-034 project is currently in the DISIS-2014-002 cluster. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2014-034 configuration. The GEN-2014-034 project interconnects in Southwestern Public Service (SPS) control area with a capacity of 70 MW as shown in Table 2-1 below.

Table 2-1: GEN-2014-034 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2014-034	Chaves County 115 kV (527482)	18 x GE 4.0 MW = 72 MW POI limited to 70 MW	70

Figure 2-1: GEN-2014-034 Single Line Diagram (Existing Configuration)



This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2014-034 to change the main power transformer but keep the existing inverter configuration of 18 x GE 4.0 MW for a total capacity of 72 MW. While the modification request did not include a change in generator configuration, the generating capacity for GEN-2014-034 (72 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 70 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 transformers, and generator power factor. Figure 2-2 shows the power flow model single line diagram for the GEN-2014-034 modification. The existing and modified configurations for GEN-2014-034 are shown in Table 2-2.

Figure 2-2: GEN-2014-034 Single Line Diagram (Modification Configuration)

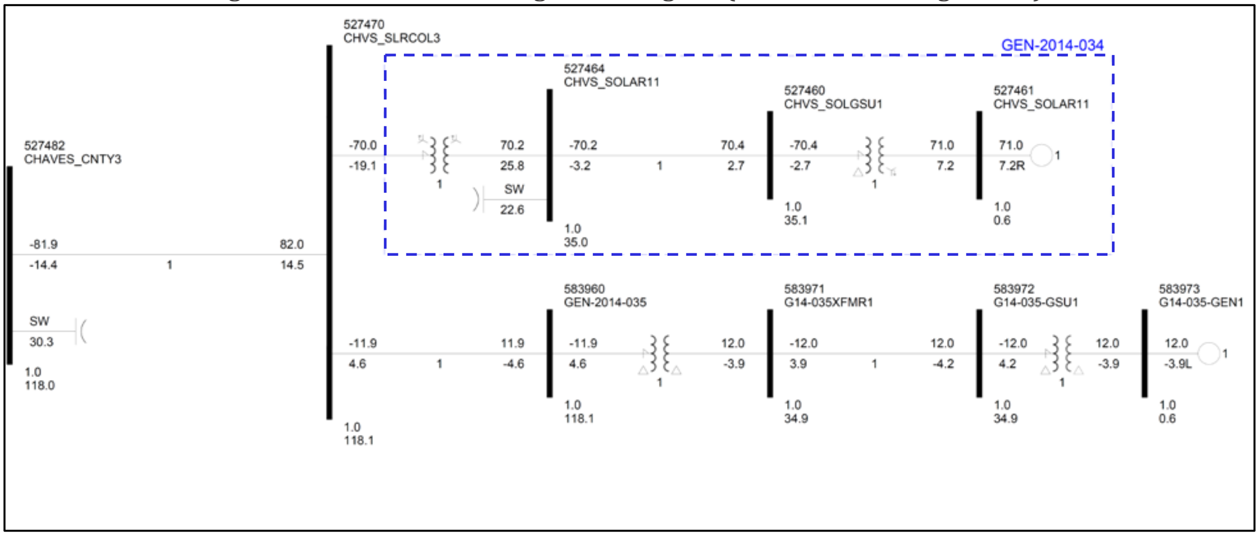


Table 2-2: GEN-2014-034 Modification Request

Facility	Existing Configuration	Modification Configuration
Point of Interconnection	Chaves County 115 kV (527482)	Chaves County 115 kV (527482)
Configuration/Capacity	18 x GE 4.0 MW = 72 MW POI limited to 70 MW	18 x GE 4.0 MW = 72 MW POI limited to 70 MW
Generation Interconnection Line	Length = 0.45 miles R = 0.000401 pu X = 0.002525 pu B = 0.000340 pu Rating MVA = 154 MVA	Length = 0.45 miles R = 0.000401 pu X = 0.002525 pu B = 0.000340 pu Rating MVA = 154 MVA
Main Substation Transformer[1]	X = 8.14%, R = 0.695%, Winding MVA = 48 MVA, Rating MVA = 80 MVA	X = 8.098%, R = 0.176%, Winding MVA = 66 MVA, Rating MVA = 110 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 18 X = 6.789%, R = 0.838%, Winding MVA = 72 MVA, Rating MVA = 72 MVA	Gen 1 Equivalent Qty: 18 X = 6.749%, R = 0.833%, Winding MVA = 72 MVA, Rating MVA = 72 MVA
Equivalent Collector Line[2]	R = 0.004678 pu X = 0.003608 pu B = 0.006730 pu	R = 0.005550 pu X = 0.003624 pu B = 0.006713 pu
Generator Dynamic Model[3] & Power Factor	18 x GE 4.0 MW (REGCAU1)[3] Leading: 1.0 Lagging: 1.0	18 x GE 4.0 MW (REGCAU1)[3] Leading: 0.989 Lagging: 0.989
Reactive Power Devices	2 x 11 MVAr 34.5 kV Capacitor	2 x 11 MVAr 34.5 kV Capacitor

1) X and R based on Winding MVA, 2) All pu are on 100 MVA Base 3) DYR stability model name

3.0 Existing vs Modification Comparison

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

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

3.1 POI Injection Comparison

The real power injection at the POI was determined using the 2025 Summer Peak case to compare the DISIS-2017-002 power flow configuration and the requested modifications for GEN-2014-034. The percentage change in the POI injection was then evaluated. If the MW difference was determined to be significant, power flow analysis would be performed to assess the impact of the modification request.

SPP determined that power flow analysis was not required due to the insignificant change (increase of 1.99%) in the real power output at the POI between the studied DISIS-2017-002 power flow configuration and requested modification shown in Table 3-1. The MW shown includes injections from GEN-2014-034 and the nearby project GEN-2014-035 which shares the gen-tie line. The nearby GEN-2014-035 project was dispatched to 40% of capacity in both the existing and modification models according to the DISIS fuel-based dispatch[2].

Table 3-1: GEN-2014-034 POI Injection Comparison

Interconnection Request	25SP Existing POI Injection (MW)	25SP Modification POI Injection (MW)	POI Injection Difference %
GEN-2014-034	80.3*	81.9*	1.99%

*The total MW amount includes the GEN-2014-035 project (dispatched to 40%) which shares the gen-tie line

3.1 Equivalent Impedance Comparison Calculation

The impedances from all the components of the transmission lines, substation and step-up transformers, and equivalent collector line impedances were added in series for GEN-2014-034 before and after the modification request. The percentage increase in the impedances before and after the modification request were then compared. If the percentage increase was greater than 10%, additional dynamic stability analysis and short circuit analysis would be performed to determine the impact of the requested modification. Table 3-2 shows the impedance differences before and after the modification request. Table 3-3 shows the increases in impedances from the original impedances to the modification request impedances.

[2] GENERATOR INTERCONNECTION MANUAL (DISIS MANUAL) Version 1.7 – October 2022

Table 3-2: GEN-2014-034 Impedance Comparison

System Component	Existing Model Impedances (p.u.)			Modification Request Impedances (p.u.)		
	R	*X*		*R*	*X*	
Gen Tie Line from POI to GEN-2014-034	0.00040	0.00253		0.00040	0.00253	
GEN-2014-034 collector system equivalent	0.00468	0.00361		0.00555	0.00362	
	R	*X*	*MVA Base*	*R*	*X*	*MVA Base*
GEN-2014-034 Main Transformer @ 100 MVA	0.01448	0.16959	100	0.00266	0.12270	100
GEN-2014-034 Unit GSU @ 100 MVA Base	0.0116	0.0943	100	0.01157	0.09373	100
	R	*X*	*Z*	*R*	*X*	*Z*
Total Impedance from POI to Collector System	0.031201	0.270009	0.271806	0.020187	0.222581	0.223494

Table 3-3: GEN-2014-034 Impedance Comparison Results

Interconnection Request	Existing Impedance Z (p.u.)	Modification Impedance Z (p.u.)	Impedance Z Absolute Difference %
GEN-2014-034 Impedance Increase	0.2718	0.2235	17.77%

SPP determined that the change in impedance (17.77%) has the potential to alter the project impact and would require dynamic stability analysis and short circuit analysis to be performed to determine the impact of the requested modification.

3.2 Stability Model Parameters Comparison

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

4.0 Charging Current Compensation Analysis

The charging current compensation analysis was performed for GEN-2014-034 to determine the capacitive charging effects during reduced generation conditions (unsuitable wind speeds, unsuitable solar irradiance, insufficient state of charge, idle conditions, curtailment, etc.) at the generation site and to size shunt reactors that would reduce the project reactive power contribution to the POI to approximately zero.

4.1 Methodology and Criteria

For this analysis the GEN-2014-035 project that shares the gen-tie line was disconnected. The GEN-2014-034 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).

Aneden performed the charging current compensation analysis using the modification request data based on the DISIS-2017-002 stability study models:

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

4.2 Results

The results from the analysis showed that the GEN-2014-034 project needed approximately 0.7 MVAr of compensation at its project substation, to reduce the POI MVAr to zero. This is an increase from the 0.88 MVAr found for the previous modification study[3]. 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-2014-034 are shown in Table 4-1.

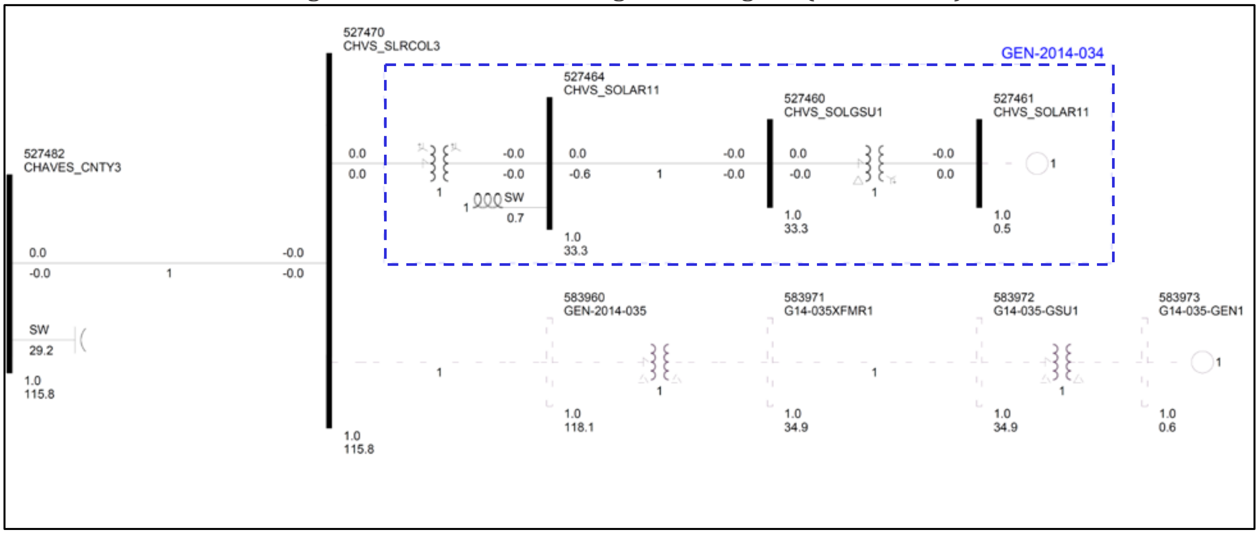
The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

Table 4-1: Shunt Reactor Size for Reduced Generation Study (Modification)

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)	
			25SP	25WP
GEN-2014-034	527482	CHAVES_CNTY3 115 kV	0.7	0.7

[3] GEN-2014-033, GEN-2014-034, GEN-2014-035 Impact Restudy for Generator Modification (Inverter change), July 2016

Figure 4-1: GEN-2014-034 Single Line Diagram (Modification)



5.0 Short Circuit Analysis

A short circuit study was performed using the 25SP model for GEN-2014-034. The detailed results of the short circuit analysis are provided in Appendix B.

5.1 Methodology

The short circuit analysis included applying a 3-phase fault on buses up to 5 levels away from the 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-2014-034 online. GEN-2014-035 was left online for this analysis.

Aneden performed the short circuit analysis using the modification request data based on the 2025 Summer Peak DISIS-2017-002 stability study model.

5.2 Results

The results of the short circuit analysis for the 25SP model are summarized in Table 5-1 and Table 5-2. The GEN-2014-034 POI bus (Chaves County 115 kV – 527482) fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 6.93 kA with the GEN-2014-034 project online.

The maximum fault current calculated within 5 buses of the GEN-2014-034 POI was less than 32 kA for the 25SP model. The maximum GEN-2014-034 contribution to three-phase fault current was about 4.9% and 0.31 kA.

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
25SP	6.62	6.93	0.31	4.7%

Table 5-2: 25SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	3.6	0.05	1.3%
115	26.9	0.31	4.9%
230	31.0	0.14	3.2%
345	13.4	0.03	0.4%
Max	**31.0**	**0.31**	**4.9%**

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the main power transformer change and other modifications to GEN-2014-034. The analysis was performed according to SPP's Disturbance Performance Requirements shown in Appendix C. The modification details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix A. The simulation plots can be found in Appendix D.

6.1 Methodology and Criteria

The dynamic stability analysis was performed using models with the existing GEN-2014-034 configuration of 18 x GE 4.0 MW (REGCA1) and updated main power transformer, collection system, generator step-up transformers, and generator power factor. This stability analysis was performed using PTI's PSS/E version 34.8 software.

The modifications requested for the GEN-2014-034 project were used to create modified stability model**s** for this impact study based on the DISIS-2017-002 stability study models:

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

The dynamic model data for the GEN-2014-034 project is provided in Appendix A. The modified power flow 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 existing base case issues that are not attributed to the modification request:

1. Deleted the duplicate Wichita to Expedition to Emporia Energy Center 345 kV line.
2. Updated the GEN-2017-198 REGCAU1 dynamic stability model to the latest version.
3. Restored the 2020 MDAG Dempsey generator dynamic stability model.
4. The GEN-2017-176 (761442, 761445, 761447, & 761449) overvoltage protection relays were disabled.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2014-034 and other equally and prior queued projects in their cluster group[4]. In addition, voltages of five (5) buses away from the POI of GEN-2014-034 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas including 520 (AEPW), 524 (OKGE), 526 (SPS), and 652 (WAPA) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

6.2 Fault Definitions

Aneden simulated the faults previously simulated for GEN-2014-034 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 defined by applying the proper fault impedance to bring the faulted bus positive sequence voltage to 0.6 p.u. The simulated

[4] Based on the DISIS-2017-001 Cluster Groups

faults are listed and described in Table 6-1 below. These contingencies were applied to the modified 2025 Summer Peak and the 2025 Winter Peak 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. 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. 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.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
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. 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.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
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.
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.
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.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
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.
FLT9036-3PH	P1	3 phase fault on the CROSSROADS 7 (527656) to YOAKUM_345 (526936) 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.
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.
FLT9002-PO2	P6	**PRIOR OUTAGE of the ABB 801429 115 kV (527482) / 230 kV (527483)/ 13.2 kV (527479) XFMR CKT 2;** 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-PO2	P6	**PRIOR OUTAGE of the ABB 801429 115 kV (527482) / 230 kV (527483)/ 13.2 kV (527479) XFMR CKT 2;** 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.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9004-PO2	P6	**PRIOR OUTAGE of the ABB 801429 115 kV (527482) / 230 kV (527483)/ 13.2 kV (527479) XFMR CKT 2;** 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. 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-PO2	P6	**PRIOR OUTAGE of the ABB 801429 115 kV (527482) / 230 kV (527483)/ 13.2 kV (527479) XFMR CKT 2;** 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-PO2	P6	**PRIOR OUTAGE of the ABB 801429 115 kV (527482) / 230 kV (527483)/ 13.2 kV (527479) XFMR CKT 2;** 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.
FLT9002-PO3	P6	**PRIOR OUTAGE of the CHAVES_CNTY3 (527482) to PRICE TAP 3 (527509) 115 kV line CKT 1;** 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.
FLT9004-PO3	P6	**PRIOR OUTAGE of the CHAVES_CNTY3 (527482) to PRICE TAP 3 (527509) 115 kV line CKT 1;** 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. 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-PO3	P6	**PRIOR OUTAGE of the CHAVES_CNTY3 (527482) to PRICE TAP 3 (527509) 115 kV line CKT 1;** 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-PO3	P6	**PRIOR OUTAGE of the CHAVES_CNTY3 (527482) to PRICE TAP 3 (527509) 115 kV line CKT 1;** 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.
FLT9002-PO4	P6	**PRIOR OUTAGE of the CHAVES_CNTY3 (527482) to URTON 3 (527501) 115 kV line CKT 1;** 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.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9003-PO4	P6	**PRIOR OUTAGE of the CHAVES_CNTY3 (527482) to URTON 3 (527501) 115 kV line CKT 1;** 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.
FLT9005-PO4	P6	**PRIOR OUTAGE of the CHAVES_CNTY3 (527482) to URTON 3 (527501) 115 kV line CKT 1;** 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-PO4	P6	**PRIOR OUTAGE of the CHAVES_CNTY3 (527482) to URTON 3 (527501) 115 kV line CKT 1;** 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.
FLT9002-PO5	P6	**PRIOR OUTAGE of the CHAVES_CNTY3 (527482) to SAMSON 3 (527546) 115 kV line CKT 1;** 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-PO5	P6	**PRIOR OUTAGE of the CHAVES_CNTY3 (527482) to SAMSON 3 (527546) 115 kV line CKT 1;** 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-PO5	P6	**PRIOR OUTAGE of the CHAVES_CNTY3 (527482) to SAMSON 3 (527546) 115 kV line CKT 1;** 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. 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-PO5	P6	**PRIOR OUTAGE of the CHAVES_CNTY3 (527482) to SAMSON 3 (527546) 115 kV line CKT 1;** 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.
FLT9002-PO1	P6	**PRIOR OUTAGE of the CHAVES_CNTY6 (527483) to EDDY_NORTH 6 (527799) 230 kV line CKT 1;** 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.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9003-PO1	P6	**PRIOR OUTAGE of the CHAVES_CNTY6 (527483) to EDDY_NORTH 6 (527799) 230 kV line CKT 1;** 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-PO1	P6	**PRIOR OUTAGE of the CHAVES_CNTY6 (527483) to EDDY_NORTH 6 (527799) 230 kV line CKT 1;** 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. 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-PO1	P6	**PRIOR OUTAGE of the CHAVES_CNTY6 (527483) to EDDY_NORTH 6 (527799) 230 kV line CKT 1;** 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-PO1	P6	**PRIOR OUTAGE of the CHAVES_CNTY6 (527483) to EDDY_NORTH 6 (527799) 230 kV line CKT 1;** 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.
FLT9018-PO1	P6	**PRIOR OUTAGE of the CHAVES_CNTY6 (527483) to EDDY_NORTH 6 (527799) 230 kV line CKT 1;** 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. 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.
FLT1001-SB	P4	**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-SB	P4	**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-SB	P4	**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-SB	P4	**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.

6.3 Results

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

Table 6-2: GEN-2014-034 Dynamic Stability Results

Fault ID	25SP			25WP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable
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 (1) (2)	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable (1) (2)	Pass	Pass	Stable
FLT9024-3PH	Pass	Pass	Stable (1) (2)	Pass	Pass	Stable
FLT9025-3PH	Pass	Pass	Stable (1) (2)	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable (1) (2)	Pass	Pass	Stable
FLT9027-3PH	Pass	Pass	Stable (1) (2)	Pass	Pass	Stable
FLT9028-3PH	Pass	Pass	Stable (1) (2)	Pass	Pass	Stable
FLT9029-3PH	Pass	Pass	Stable (1) (2)	Pass	Pass	Stable

Table 6-2 continued

Fault ID	25SP			25WP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9030-3PH	Pass	Pass	Stable (1) (2)	Pass	Pass	Stable
FLT9031-3PH	Pass	Pass	Stable (1) (2)	Pass	Pass	Stable
FLT9032-3PH	Pass	Pass	Stable (1) (2)	Pass	Pass	Stable
FLT9033-3PH	Pass	Pass	Stable (1) (2)	Pass	Pass	Stable
FLT9034-3PH	Pass	Pass	Stable (1) (2)	Pass	Pass	Stable
FLT9035-3PH	Pass	Pass	Stable (1) (2)	Pass	Pass	Stable
FLT9036-3PH	Pass	Pass	Stable (1) (2)	Pass	Pass	Stable
FLT9037-3PH	Fail (1)	Pass	Stable (1) (2)	Pass	Pass	Stable
FLT9038-3PH	Pass	Pass	Stable (1) (2)	Pass	Pass	Stable
FLT9039-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable
FLT9040-3PH	Pass	Pass	Stable (1) (2)	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
FLT9002-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-PO1	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO2	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO3	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO3	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO3	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO3	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO4	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO4	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-PO4	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO4	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO5	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	25SP			25WP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT9003-PO5	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO5	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO5	Pass	Pass	Stable	Pass	Pass	Stable

(1) Sagamore units showed slow recovery, observed in both the pre and post modification models
(2) Cunninham Unit 4 reactive power oscillations observed in both the pre and post modification models

The Sagamore generators showed a slow active power (P) and reactive power (Q) recovery under several P1 contingencies which caused voltage recovery violations. Similar responses were also observed in the DISIS-2017-002 case without the GEN-2014-034 modification as shown in Figure 6-1 below and with the GEN-2014-034 modification as shown in Figure 6-2. Therefore, this issue is not attributed to the GEN-2014-034 modification request.

Figure 6-1: FLT9025-3PH Sagamore Units Slow P & Q Recovery (25SP DISIS Case)

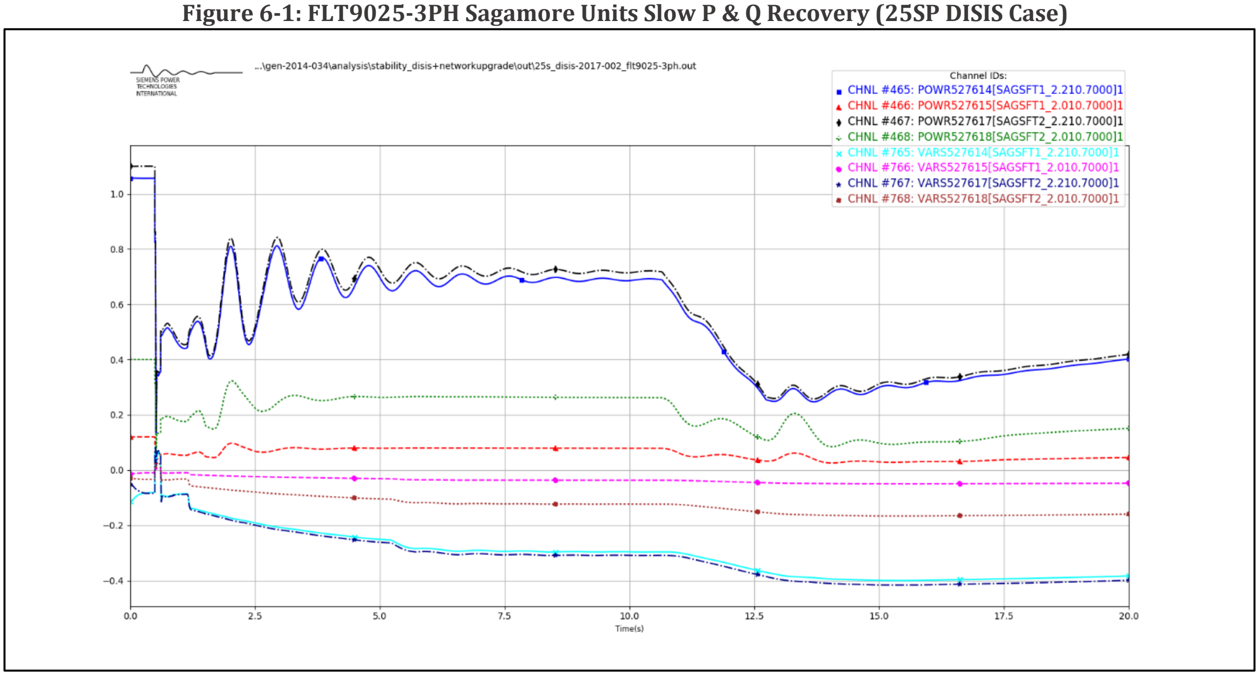
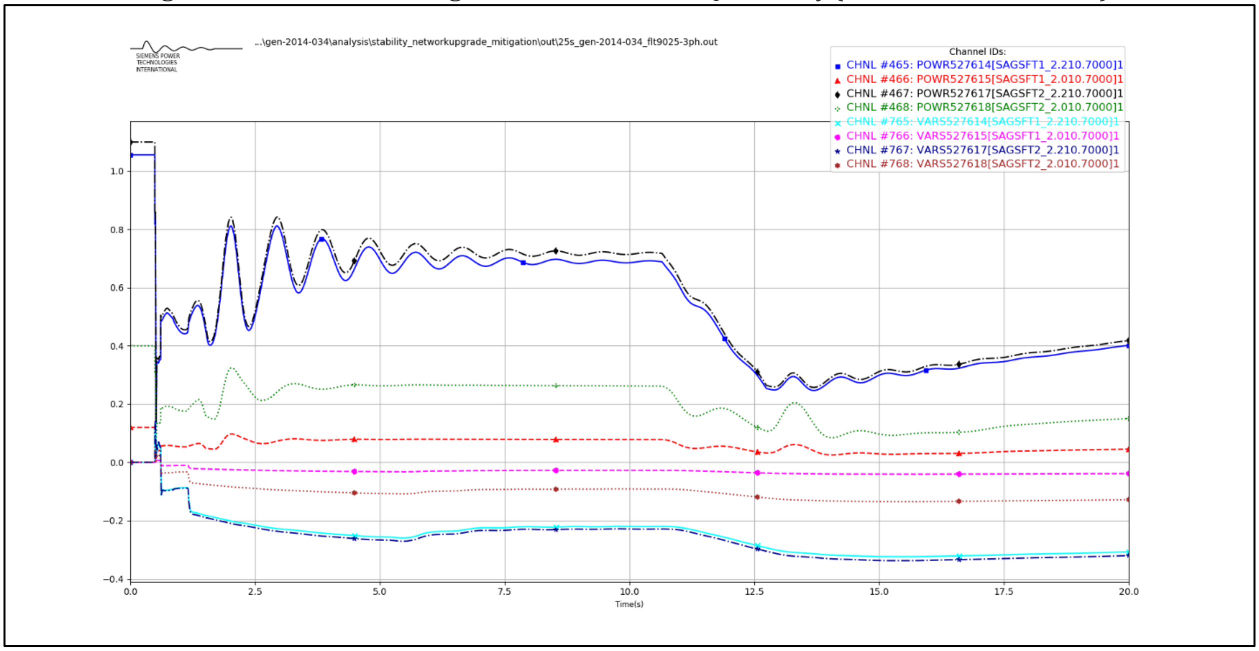


Figure 6-2: FLT9025-3PH Sagamore Units Slow P & Q Recovery (25SP Modification Case)



Oscillations were observed for Cunningham Unit 4 under several P1 contingencies both in the DISIS-2017-002 case without the GEN-2014-034 modification as shown in Figure 6-3 below and with the GEN-2014-034 modification as shown in Figure 6-4. Therefore, the oscillations were not attributed to the GEN-2014-034 modification request.

Figure 6-3: FLT9025-3PH Cunningham Unit 4 Oscillations (25SP DISIS Case)

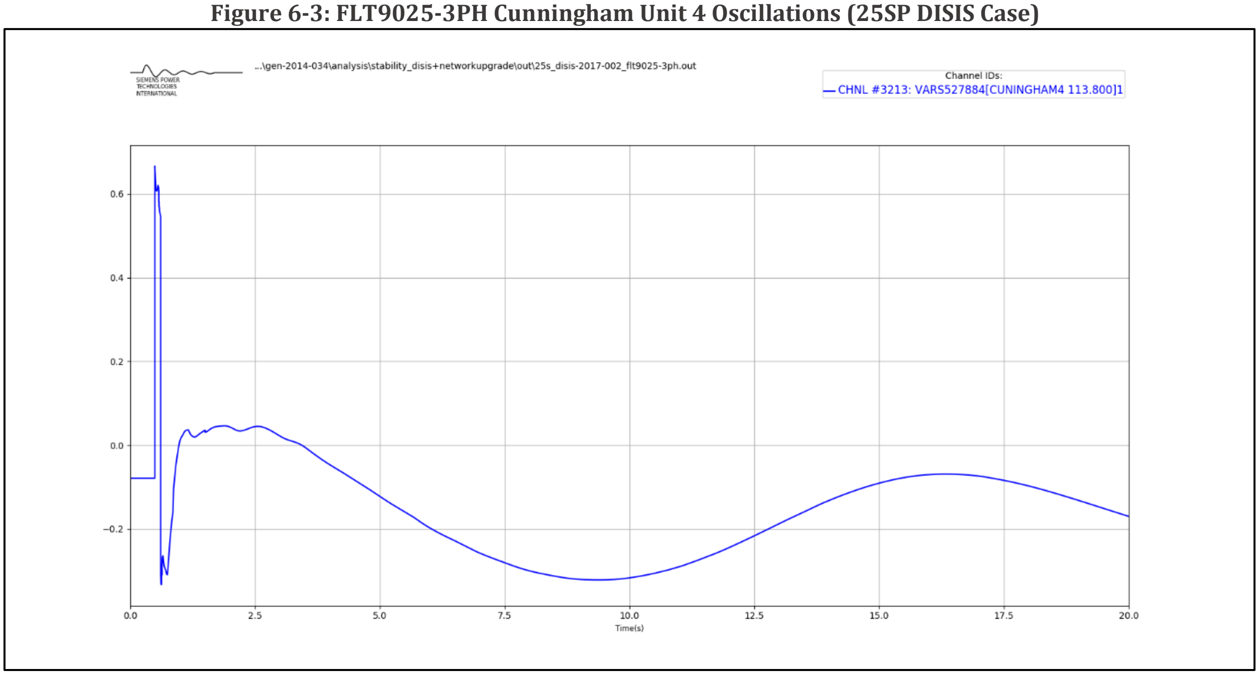
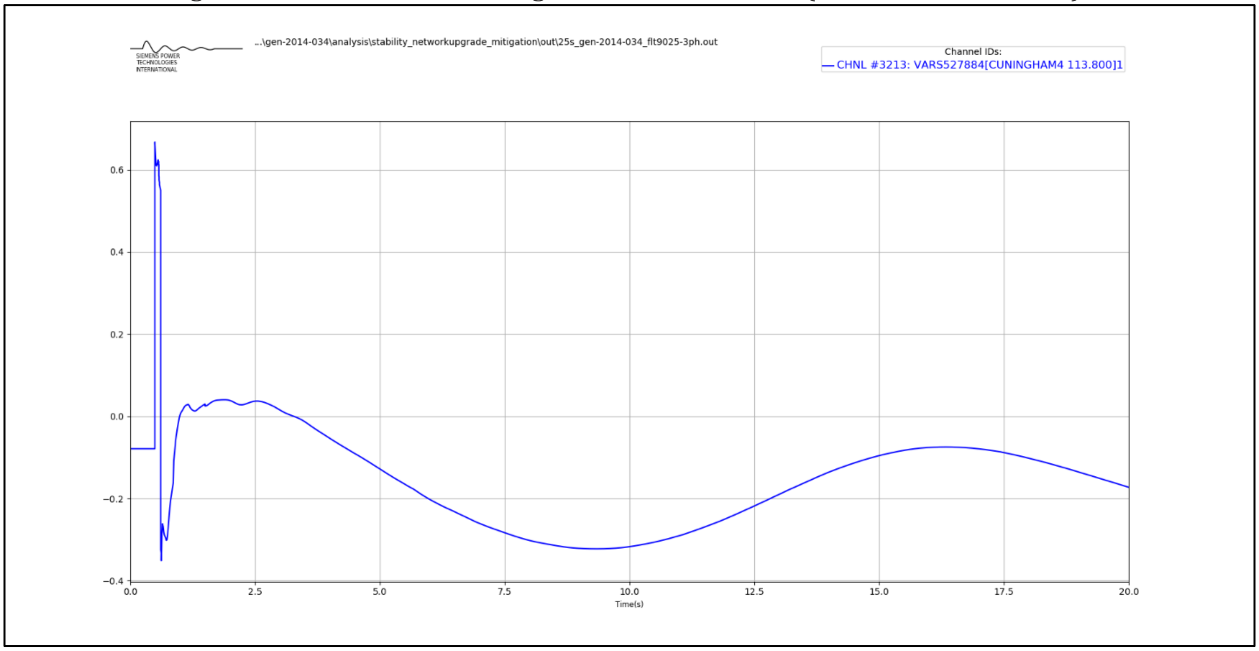


Figure 6-4: FLT9025-3PH Cunningham Unit 4 Oscillations (25SP Modification Case)



There were no damping or voltage recovery violations attributed to the GEN-2014-034 project observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

7.0 Modified Capacity Exceeds GIA Capacity

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

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

7.1 Results

While the modification request did not include a change in generator configuration, the generating capacity of GEN-2014-034 (72 MW) exceeds the GIA Interconnection Service amount, 70 MW, as listed in Appendix A of the GIA.

The customer must install monitoring and control equipment as needed to ensure that the amount of power injected at the POI does not exceed the Interconnection Service amount listed in its GIA.

8.0 Material Modification Determination

In accordance with Attachment V of SPP's Open Access Transmission Tariff, for modifications other than those specifically permitted by Attachment V, SPP shall evaluate the proposed modifications prior to making them and inform the Interconnection Customer in writing of whether the modifications would constitute a Material Modification. Material Modification shall mean (1) modification to an Interconnection Request in the queue that has a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date; or (2) planned modification to an Existing Generating Facility that is undergoing evaluation for a Generating Facility Modification or Generating Facility Replacement, and has a material adverse impact on the Transmission System with respect to: i) steady-state thermal or voltage limits, ii) dynamic system stability and response, or iii) short-circuit capability limit; compared to the impacts of the Existing Generating Facility prior to the modification or replacement.

8.1 Results

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

This determination implies that any network upgrades already required by GEN-2014-034 would not be negatively impacted and that no new upgrades are required due to the requested modification, thus not resulting in a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date.

9.0 Conclusions

The Interconnection Customer for GEN-2014-034 requested a Modification Request Impact Study to assess the impact of the main power transformer facility change but with the existing inverter configuration of 18 x GE 4.0 MW for a total capacity of 72 MW. While the modification request did not include a change in generator configuration, the generating capacity for GEN-2014-034 (72 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 70 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 transformers, and generator power factor.

SPP determined that power flow should not be performed based on the POI MW injection increase of 1.99% compared to the DISIS-2017-002 power flow models. As the existing and modification configurations kept the same inverter configuration, an equivalent impedance comparison was performed in order to determine the potential impact of the requested change. SPP determined that because the equivalent impedance change of 17.77% was above the 10% threshold, the modification request required dynamic stability and short circuit analyses.

All analyses were performed using the PTI PSS/E version 34 software and the results are summarized below.

The results of the charging current compensation analysis using the 2025 Summer Peak and 2025 Winter Peak models showed that the GEN-2014-034 project needed a 0.7 MVAr shunt reactor on the 34.5 kV bus of the project substation with the modifications in place, a decrease from the 0.88 MVAr found for the previous modification study[5]. 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 model. The results from the short circuit analysis with the updated topology showed that the maximum GEN-2014-034 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2014-034 POI was no greater than 0.31 kA. All three-phase fault current levels within 5 buses of the POI with the GEN-2014-034 generators online were below 32 kA.

The dynamic stability analysis was performed using PTI PSS/E version 34.8 software for the two modified study models: 2025 Summer Peak and 2025 Winter Peak. 66 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults.

[5] GEN-2014-033, GEN-2014-034, GEN-2014-035 Impact Restudy for Generator Modification (Inverter change), July 2016

The results of the dynamic stability analysis showed that there were several stability base case issues observed in the DISIS-2017-002 case both with and without the GEN-2014-034 modification. These were not attributed to the GEN-2014-034 modification request.

1. The Sagamore generators showed a slow active power (P) and reactive power (Q) recovery under several P1 contingencies which caused voltage recovery violations.
2. Oscillations were observed for Cunningham Unit 4 under several P1 contingencies.

The results of the dynamic stability analysis showed that there were no damping or voltage recovery violations attributed to the GEN-2014-034 project observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

The requested modification has been determined by SPP to not be a Material Modification. The requested modification does not have a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date. As the project configuration 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.