Report on

GEN-2014-001 Modification Request Impact Study

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Submitted to
Southwest Power Pool

SPP Southwest Power Pool

anedenconsulting.com

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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-2014-001, an active Generation Interconnection Request (GIR) with a point of interconnection (POI) at the G14-001-TAP 345 kV bus tapping the Emporia Energy Center to Wichita 345 kV line.

The GEN-2014-001 project interconnects in the Evergy Kansas Central (WERE), control area with a capacity of 200.6 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2014-001 to change the turbine configuration to 76 x GE 2.82 MW for a total capacity of 214.32 MW. This generating capacity for GEN-2014-001 (214.32 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 200.6 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. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI. In addition, the modification request included changes to the collection system, generator step-up transformers, generation interconnection line, and main substation transformers. The existing and modified configurations for GEN-2014-001 are shown in Table ES-2.

Table ES-1: GEN-2014-001 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2014-001	Tap on Emporia Energy Center 345 kV (532768) to Wichita 345 kV (532796) (G14-001-TAP 562476)	64 x GE 2.82 MW + 8 x GE 2.3 MW = 198.88 MW	200.6

Table ES-2: GEN-2014-001 Modification Request

Facility	Existing Configuration		Modification Configuration	
Point of Interconnection	Tap on Emporia Energy Center 345 kV (532768) to Wichita 345 kV (532796) (G14-001-TAP 562476)		Tap on Emporia Energy Center 345 kV (532768) to Wichita 345 kV (532796) (G14-001-TAP 562476)	
Configuration/Capacity	64 x GE 2.82 MW + 8 x GE 2.3 MW = 198.88 MW		76 x GE 2.82 MW = 214.32 MW PPC to limit POI to 200.6 MW	
Generation Interconnection Line	<u>G14-001-TAP to GEN-2014-001:</u> Length = 17.4 miles R = 0.000870 pu X = 0.008530 pu B = 0.144910 pu Rating MVA = 0 MVA		<u>G14-001-TAP to GEN-2014-001:</u> Length = 10.7 miles R = 0.000542 pu X = 0.005124 pu B = 0.094926 pu Rating MVA = 759 MVA	<u>GEN-2014-001 to GEN-2014-001:</u> Length = 12.06 miles R = 0.000618 pu X = 0.005712 pu B = 0.109372 pu Rating MVA = 759 MVA
Main Substation Transformer[1]	X = 9.997%, R = 0.25%, Winding MVA = 135 MVA, Rating MVA = 225 MVA		<u>Transformer T1:</u> X = 9.601%, R = 0.195%, Winding MVA = 126 MVA, Rating MVA = 210 MVA	<u>Transformer T2:</u> X = 9.998%, R = 0.2%, Winding MVA = 106 MVA, Rating MVA = 177 MVA
Equivalent GSU Transformer[1]	<u>Gen 1 Equivalent Qty: 8</u> X = 5.722%, R = 0.572%, Winding MVA = 26 MVA, Rating MVA = 26 MVA	<u>Gen 2 Equivalent Qty: 64</u> X = 5.722%, R = 0.572%, Winding MVA = 208 MVA, Rating MVA = 208 MVA	<u>Gen 1 Equivalent Qty: 39</u> X = 7.125%, R = 0.712%, Winding MVA = 122.85 MVA, Rating MVA[2] = 122.8 MVA	<u>Gen 2 Equivalent Qty: 37</u> X = 7.125%, R = 0.712%, Winding MVA = 116.55 MVA, Rating MVA[2] = 116.6 MVA
Equivalent Collector Line[3]	R = 0.003516 pu X = 0.004349 pu B = 0.067014 pu		R = 0.006504 pu X = 0.009359 pu B = 0.040359 pu	R = 0.005505 pu X = 0.008145 pu B = 0.034074 pu
Generator Dynamic Model[4] & Power Factor	8 x GE 2.3 MW (GEWTGCU1)[4] Leading: 0.90 Lagging: 0.90	64 x GE 2.82 MW (GEWTGCU1)[4] Leading: 0.90 Lagging: 0.90	39 x GE 2.82 MW (REGCA1)[4] Leading: 0.90 Lagging: 0.90	37 x GE 2.82 MW (REGCA1)[4] Leading: 0.90 Lagging: 0.90

1) X and R based on Winding MVA, 2) Rating rounded in PSS/E, 3) All pu are on 100 MVA Base 4) DYR stability model name

SPP determined that power flow should not be performed based on the POI MW injection increase of 1.04% compared to the DISIS-2017-002 power flow models. However, SPP determined that while the modification used the same turbine manufacturer, GE, the change in stability model from GEWTGCU1 to REGCA1 required short circuit and dynamic stability analyses.

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

Aneden performed the analyses using the modification request data based on the 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-2014-001 project needed a 28.3 MVAr shunt reactor on the 34.5 kV bus of the project substation with the modifications in place, an increase from the 21.2 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 low-wind or no-wind conditions. The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

The 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-2014-001 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2014-001 POI was no greater than 0.98 kA. All three-phase fault current levels within 5 buses of the POI with the GEN-2014-001 generators online were below 44 kA. There were several buses with a maximum fault current of over 40 kA. These buses are highlighted in Appendix B.

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-2014-001 modification. These were not attributed to the GEN-2014-001 modification request.

1. GEN-2017-203 GEN 1 Unit 1 (760812) and GEN 2 Unit 2 (760815) tripped with the loss of the RENFROW7 to G17-185-TAP 345 kV line due to frequency relays.
2. Oscillations were observed for several units including GEN-2015-052, GEN-2017-082, GEN-2017-005, GEN-2017-119, and GEN-2017-120 under multiple contingencies.

[1] GEN-2014-001 Impact Restudy for Generator Modification, January 2020

3. Several units including GEN-2011-008, GEN-2017-121, GEN-2017-009, and PRQNW_G_1 did not reach a stable active power within 20 seconds under multiple contingencies.

There were no damping or voltage recovery violations attributed to the GEN-2014-001 project observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

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

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

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

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

1.0 Scope of Study

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2014-001. 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 turbine 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

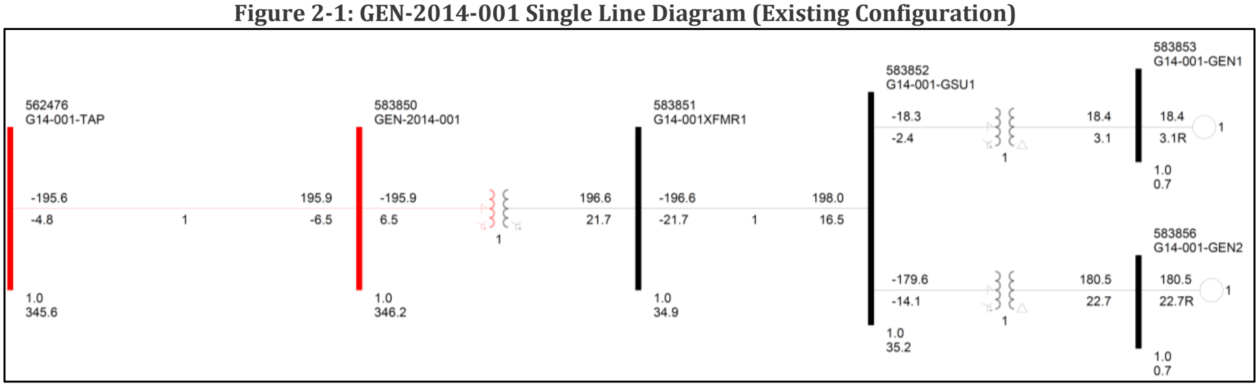
The GEN-2014-001 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a point of interconnection (POI) at the G14-001-TAP 345 kV bus tapping the Emporia Energy Center to Wichita 345 kV line. At the time of the posting of this report, GEN-2014-001 is an active Interconnection Request with a queue status of "IA FULLY EXECUTED/ON SCHEDULE." GEN-2014-001 is a wind farm with a maximum summer and winter queue capacity of 200.6 MW with Energy Resource Interconnection Service (ERIS).

The GEN-2014-001 project is currently in the DISIS-2014-001 cluster. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2014-001 configuration. The GEN-2014-001 project interconnects in the Evergy Kansas Central (WERE) control area with a capacity of 200.6 MW as shown in Table 2-1 below.

Table 2-1: GEN-2014-001 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2014-001	Tap on Emporia Energy Center 345 kV (532768) to Wichita 345 kV (532796) (G14-001-TAP 562476)	64 x GE 2.82 MW + 8 x GE 2.3 MW = 198.88 MW	200.6

Figure 2-1: GEN-2014-001 Single Line Diagram (Existing Configuration)



This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2014-001 to a turbine configuration of 76 x GE 2.82 MW for a total capacity of 214.32 MW. This generating capacity for GEN-2014-001 (214.32 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 200.6 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. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI.

In addition, the modification request included changes to the collection system, generator step-up transformers, generation interconnection line, and main substation transformers. Figure 2-2 shows the power flow model single line diagram for the GEN-2014-001 modification. The existing and modified configurations for GEN-2014-001 are shown in Table 2-2.

Figure 2-2: GEN-2014-001 Single Line Diagram (Modification Configuration)

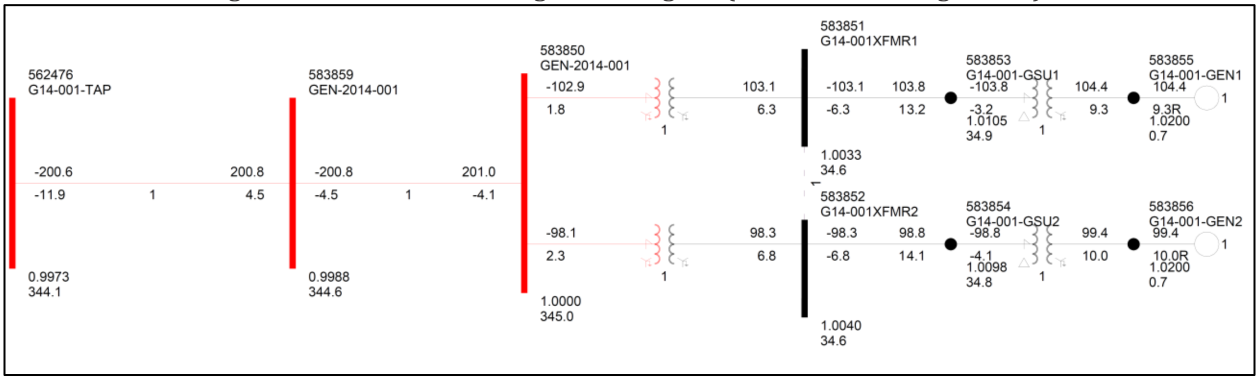


Table 2-2: GEN-2014-001 Modification Request

Facility	Existing Configuration		Modification Configuration	
Point of Interconnection	Tap on Emporia Energy Center 345 kV (532768) to Wichita 345 kV (532796) (G14-001-TAP 562476)		Tap on Emporia Energy Center 345 kV (532768) to Wichita 345 kV (532796) (G14-001-TAP 562476)	
Configuration/Capacity	64 x GE 2.82 MW + 8 x GE 2.3 MW = 198.88 MW		76 x GE 2.82 MW = 214.32 MW PPC to limit POI to 200.6 MW	
Generation Interconnection Line	G14-001-TAP to GEN-2014-001: Length = 17.4 miles R = 0.000870 pu X = 0.008530 pu B = 0.144910 pu Rating MVA = 0 MVA		G14-001-TAP to GEN-2014-001: Length = 10.7 miles R = 0.000542 pu X = 0.005124 pu B = 0.094926 pu Rating MVA = 759 MVA	GEN-2014-001 to GEN-2014-001: Length = 12.06 miles R = 0.000618 pu X = 0.005712 pu B = 0.109372 pu Rating MVA = 759 MVA
Main Substation Transformer[1]	X = 9.997%, R = 0.25%, Winding MVA = 135 MVA, Rating MVA = 225 MVA		Transformer T1: X = 9.601%, R = 0.195%, Winding MVA = 126 MVA, Rating MVA = 210 MVA	Transformer T2: X = 9.998%, R = 0.2%, Winding MVA = 106 MVA, Rating MVA = 177 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 8 X = 5.722%, R = 0.572%, Winding MVA = 26 MVA, Rating MVA = 26 MVA	Gen 2 Equivalent Qty: 64 X = 5.722%, R = 0.572%, Winding MVA = 208 MVA, Rating MVA = 208 MVA	Gen 1 Equivalent Qty: 39 X = 7.125%, R = 0.712%, Winding MVA = 122.85 MVA, Rating MVA[2] = 122.8 MVA	Gen 2 Equivalent Qty: 37 X = 7.125%, R = 0.712%, Winding MVA = 116.55 MVA, Rating MVA[2] = 116.6 MVA
Equivalent Collector Line[3]	R = 0.003516 pu X = 0.004349 pu B = 0.067014 pu		R = 0.006504 pu X = 0.009359 pu B = 0.040359 pu	R = 0.005505 pu X = 0.008145 pu B = 0.034074 pu
Generator Dynamic Model[4] & Power Factor	8 x GE 2.3 MW (GEWTGCU1)[4] Leading: 0.90 Lagging: 0.90	64 x GE 2.82 MW (GEWTGCU1)[4] Leading: 0.90 Lagging: 0.90	39 x GE 2.82 MW (REGCA1)[4] Leading: 0.90 Lagging: 0.90	37 x GE 2.82 MW (REGCA1)[4] Leading: 0.90 Lagging: 0.90

1) X and R based on Winding MVA, 2) Rating rounded in PSS/E, 3) All pu are on 100 MVA Base 4) 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 PSS/E to compare the DISIS-2017-002 power flow configuration and the requested modifications with the PPC in place for GEN-2014-001. 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 1.04%) 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.

Table 3-1: GEN-2014-001 POI Injection Comparison

Interconnection Request	Existing POI Injection (MW)	Modification POI Injection (MW)	POI Injection Difference %
GEN-2014-001	198.5	200.6	1.04%

3.2 Turbine Parameters Comparison

SPP determined that while the modification used the same turbine manufacturer, GE, the change in stability model from GEWTGCU1 to REGCA1 required short circuit and dynamic stability analysis. This is because the short circuit contribution and stability responses of the existing configuration and the requested modification's configuration may differ. The generator dynamic model for the modification can be found in Appendix A.

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

3.3 Equivalent Impedance Comparison Calculation

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

4.0 Charging Current Compensation Analysis

The charging current compensation analysis was performed for GEN-2014-001 to determine the capacitive charging effects during reduced generation conditions (unsuitable wind speeds, unsuitable solar irradiance, insufficient state of charge, idle conditions, curtailment, etc.) at the generation site and to size shunt reactors that would reduce the project reactive power contribution to the POI to approximately zero.

4.1 Methodology and Criteria

The GEN-2014-001 generators 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-2014-001 project needed approximately 28.3 MVAr of compensation at its project substation, to reduce the POI MVAr to zero. This is an increase from the 21.2 MVAr found for the previous modification study[2]. 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-2014-001 are shown in Table 4-1.

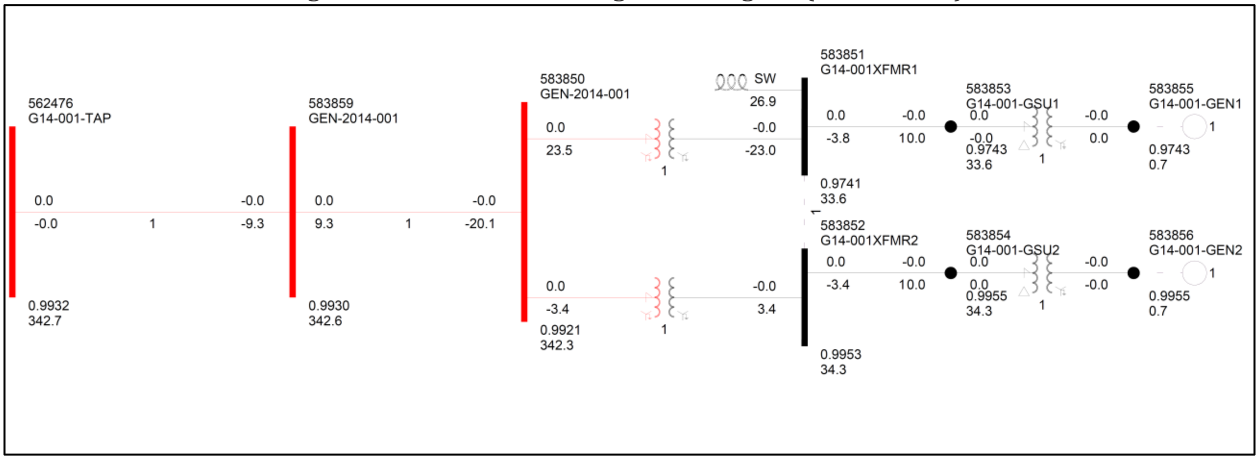
The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission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

Table 4-1: Shunt Reactor Size for Low Wind Study (Modification)

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)	
			25SP	25WP
GEN-2014-001	562476	G14-001-TAP 345 kV	28.3	28.3

[2] GEN-2014-001 Impact Restudy for Generator Modification, January 2020

Figure 4-1: GEN-2014-001 Single Line Diagram (Modification)



5.0 Short Circuit Analysis

A short circuit study was performed using the 25SP model for GEN-2014-001. The detailed results of the short circuit analysis are provided in Appendix B.

5.1 Methodology

The short circuit analysis included applying a 3-phase fault on buses up to 5 levels away from the 345 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels in the transmission system with and without GEN-2014-001 online.

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-2014-001 POI bus (G14-001-TAP 345 kV - 562476) fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 11.05 kA with the GEN-2014-001 project online.

The maximum fault current calculated within 5 buses of the GEN-2014-001 POI was less than 44 kA for the 25SP model. There were several buses with a maximum fault current of over 40 kA. These buses are highlighted in Appendix B. The maximum GEN-2014-001 contribution to three-phase fault current was about 9.7% and 0.98 kA.

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
25SP	10.08	11.05	0.98	9.7%

Table 5-2: 25SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	19.5	0.03	0.1%
115	26.0	0.05	0.3%
138	31.1	0.20	0.6%
161	43.6	0.01	0.0%
230	24.8	0.04	0.2%
345	28.9	0.98	9.7%
Max	**43.6**	**0.98**	**9.7%**

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the turbine configuration change and other modifications to GEN-2014-001. The analysis was performed according to SPP's Disturbance Performance Requirements shown in Appendix C. The modification details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix A. The simulation plots can be found in Appendix D.

6.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested GEN-2014-001 configuration of 76 x GE 2.82 MW (REGCA1). This stability analysis was performed using PTI's PSS/E version 34.8 software.

The modifications requested for the GEN-2014-001 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 modified dynamic model data for the GEN-2014-001 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-2017-121 (761841), GEN-2011-008 (539845, 539846, 539847, 539848, 539852, 539853), GEN-2016-153 (588363), GEN-2017-086 (589243), GEN-2017-221 (760307), GEN-2017-227 (760664), and GEN-2017-192 (761967) voltage protection relays were disabled.
5. The GEN-2017-086 (589243) frequency protection relays were disabled.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2014-001 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-2014-001 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas including 330 (AECI), 356 (AMMO), 515 (SWPA), 523 (GRDA), 524 (OKGE), 526 (SPS), 531 (MIDW), 534 (SUNC), 536 (WERE), 541 (KCPL), 544 (EMDE) and 635 (MEC) 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-2014-001 and developed additional fault events as required. The new set of faults were simulated using the modified study models.

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

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 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
FLT10-3PH	P1	3 phase fault on the BENTON 7 (532791) to ROSEHIL7 (532794) 345 kV line CKT 1, near BENTON 7. a. Apply fault at the BENTON 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.
FLT11-3PH	P1	3 phase fault on the BENTON 7 (532791) to WICHITA 7 (532796) 345 kV line CKT 1, near BENTON 7. a. Apply fault at the BENTON 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.
FLT12-3PH	P1	3 phase fault on the BENTON 7 (532791) to WOLFCRK7 (532797) 345 kV line CKT 1, near BENTON 7. a. Apply fault at the BENTON 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.
FLT16-3PH	P1	3 phase fault on the EMPEC 7 (532768) to MORRIS 7 (532770) 345 kV line CKT 1, near EMPEC 7. a. Apply fault at the EMPEC 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.
FLT17-3PH	P1	3 phase fault on the EMPEC 7 (532768) to SWISVAL7 (532774) 345 kV line CKT 1, near EMPEC 7. a. Apply fault at the EMPEC 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.
FLT22-3PH	P1	3 phase fault on the JEC N 7 (532766) to MORRIS 7 (532770) 345 kV line CKT 1, near JEC N 7. a. Apply fault at the JEC N 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.
FLT27-3PH	P1	3 phase fault on the RENO 7 (532771) to WICHITA7 (532796) 345 kV line CKT 1, near RENO 7. a. Apply fault at the RENO 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.
FLT28-3PH	P1	3 phase fault on the ROSEHIL7 (532794) to WOLFCRK7 (532797) 345 kV line CKT 1, near ROSEHIL7. a. Apply fault at the ROSEHIL7 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.
FLT32-3PH	P1	3 phase fault on the WICHITA7 (532796) to VIOLA 7 (532798) 345 kV line CKT 1, near WICHITA7. a. Apply fault at the WICHITA7 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.
FLT165-3PH	P1	3 phase fault on the BUFFALO7 (532782) to THISTLE7 (539801) 345 kV line CKT 1, near BUFFALO7. a. Apply fault at the BUFFALO7 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
FLT166-3PH	P1	3 phase fault on the BUFFALO7 (532782) to THISTLE7 (539801) 345 kV line CKT 2, near BUFFALO7. a. Apply fault at the BUFFALO7 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.
FLT167-3PH	P1	3 phase fault on the BUFFALO7 (532782) to WICHITA7 (532796) 345 kV line CKT 1, near BUFFALO7. a. Apply fault at the BUFFALO7 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.
FLT168-3PH	P1	3 phase fault on the BUFFALO7 (532782) to WICHITA7 (532796) 345 kV line CKT 2, near BUFFALO7. a. Apply fault at the BUFFALO7 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.
FLT197-3PH	P1	3 phase fault on the LANG1 345 kV (532769) / 115 kV (533304)/ 14.4 kV (532808) XFMR CKT 1, near LANG 7 (532769) 345 kV. a. Apply fault at the LANG 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT353-3PH	P1	3 phase fault on the RENO 7 (532771) to G16-111-TAP (587884) 345 kV line CKT 1, near RENO 7. a. Apply fault at the RENO 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.
FLT354-3PH	P1	3 phase fault on the SUMMIT 7 (532773) to G16-111-TAP (587884) 345 kV line CKT 1, near SUMMIT 7. a. Apply fault at the SUMMIT 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.
FLT355-3PH	P1	3 phase fault on the RENFROW7 (515543) to G17-185-TAP (762262) 345 kV line CKT 1, near RENFROW7. a. Apply fault at the RENFROW7 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.
FLT356-3PH	P1	3 phase fault on the VIOLA 7 (532798) to G17-185-TAP (762262) 345 kV line CKT 1, near VIOLA 7. a. Apply fault at the VIOLA 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.
FLT459-3PH	P1	3 phase fault on the EMPEC 7 (532768) to G14-001-TAP (562476) 345 kV line CKT 1, near EMPEC 7. a. Apply fault at the EMPEC 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.
FLT462-3PH	P1	3 phase fault on the WICHITA7 (532796) to G14-001-TAP (562476) 345 kV line CKT 1, near WICHITA7. a. Apply fault at the WICHITA7 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.
FLT717-3PH	P1	3 phase fault on the MORRIS TX-1 345 kV (532770) / 230 kV (532863)/ 14.4 kV (532809) XFMR CKT 1, near MORRIS 7 (532770) 345 kV. a. Apply fault at the MORRIS 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT718-3PH	P1	3 phase faults on the RENO TX-1 345 kV (532771) / 138 kV (533416)/ 14.4 kV (532807) XFMR CKT 1, near RENO 7 (532771) 345 kV. a. Apply fault at the RENO 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT719-3PH	P1	3 phase fault on the RENO TX-2 345 kV (532771) / 138 kV (533416)/ 14.4 kV (532810) XFMR CKT 1, near RENO 7 (532771) 345 kV. a. Apply fault at the RENO 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT723-3PH	P1	3 phase fault on the SWISSVL TX-1 345 kV (532774) / 230 kV (532856)/ 14.4 kV (532815) XFMR CKT 1, near SWISVAL7 (532774) 345 kV. a. Apply fault at the SWISVAL7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT724-3PH	P1	3 phase fault on the SWISSVL TX-1 345 kV (532774) / 230 kV (532856)/ 14.4 kV (532819) XFMR CKT 2, near SWISVAL7 (532774) 345 kV. a. Apply fault at the SWISVAL7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT726-3PH	P1	3 phase fault on the BENT TX-1 345 kV (532791) / 138 kV (532986)/ 13.8 kV (532821) XFMR CKT 1, near BENTON 7 (532791) 345 kV. a. Apply fault at the BENTON 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT727-3PH	P1	3 phase fault on the BENT TX-2 345 kV (532791) / 138 kV (532986)/ 13.8 kV (532822) XFMR CKT 1, near BENTON 7 (532791) 345 kV. a. Apply fault at the BENTON 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT731-3PH	P1	3 phase fault on the SWISVAL7 (532774) to W.GRDNR7 (542965) 345 kV line CKT 1, near SWISVAL7. a. Apply fault at the SWISVAL7 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.
FLT734-3PH	P1	3 phase fault on the WICHITA 121 345 kV (532796) / 138 kV (533040)/ 13.8 kV (532830) XFMR CKT 1, near WICHITA7 (532796) 345 kV. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT736-3PH	P1	3 phase fault on the SCJ TX-1 345 kV (532798) / 138 kV (533075)/ 13.8 kV (532832) XFMR CKT 1, near VIOLA 7 (532798) 345 kV. a. Apply fault at the VIOLA 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT757-3PH	P1	3 phase fault on the SCJ TX-1 345 kV (532798) / 138 kV (533075)/ 13.8 kV (999532) XFMR CKT 2, near VIOLA 7 (532798) 345 kV. a. Apply fault at the VIOLA 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9001-3PH	P1	3 phase fault on the G14-001-TAP (562476) to EMPEC 7 (532768) to 345 kV line CKT 1, near G14-001-TAP. a. Apply fault at the G14-001-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	P1	3 phase fault on the G14-001-TAP (562476) to WICHITA7 (532796) to 345 kV line CKT 1, near G14-001-TAP. a. Apply fault at the G14-001-TAP 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.
FLT9003-3PH	P1	3 phase fault on the EMPEC 7 (532768) to READWF 7 (532776) 345 kV line CKT 1, near EMPEC 7. a. Apply fault at the EMPEC 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. Trip the generator R1 WF 1 (534042)

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT9004-3PH	P1	3 phase fault on the EMPEC 7 (532768) to LANG 7 (532769) 345 kV line CKT 1, near EMPEC 7. a. Apply fault at the EMPEC 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.
FLT9005-3PH	P1	3 phase fault on the EMP EC 5GUS 345 kV (532768) / 18 kV (532742) XFMR CKT 1, near EMPEC 7 (532768) 345 kV. a. Apply fault at the EMPEC 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer. **Trip the generator EMPEC5 1 (532742)**
FLT9006-3PH	P1	3 phase fault on the READING WI1 345 kV (532776) / 34.5 kV (534040)/ 13.8 kV (534043) XFMR CKT 1, near READWF 7 (532776) 345 kV. a. Apply fault at the READWF 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer. **Trip the generator R1 WF 1 (534042)**
FLT9007-3PH	P1	3 phase fault on the SWISVAL7 (532774) to GEN-2017-191 (761943) 345 kV line CKT 1, near SWISVAL7. a. Apply fault at the SWISVAL7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip the generator G17-191GEN1 (761946), G17-192GEN1 (761967).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	P1	3 phase fault on the SWISVAL7 (532774) to GEN-2017-125 (761901) 345 kV line CKT 1, near SWISVAL7. a. Apply fault at the SWISVAL7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip the generator G17-125GEN1 (761904), G17-142GEN1 (761988), G17-128GEN1 (761925).** 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.
FLT9009-3PH	P1	3 phase fault on the MORRIS 7 (532770) to JEC N 7 (532766) 345 kV line CKT 1, near MORRIS 7. a. Apply fault at the MORRIS 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.
FLT9010-3PH	P1	3 phase fault on the WICHITA7 (532796) to RENO 7 (532771) 345 kV line CKT 1, near WICHITA7. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9011-3PH	P1	3 phase fault on the WICHITA 7 (532796) to BENTON 7 (532791) 345 kV line CKT 1, near WICHITA 7. a. Apply fault at the WICHITA 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.
FLT9012-3PH	P1	3 phase fault on the WICHITA7 (532796) to BUFFALO7 (532782) 345 kV line CKT 1, near WICHITA7. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9013-3PH	P1	3 phase fault on the BENTON 7 (532791) to GEN-2016-162 (588320) 345 kV line CKT 1, near BENTON 7. a. Apply fault at the BENTON 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip the generator G16-162-GEN1 (588323), G16-163-GEN1 (588333).** 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
FLT9014-3PH	P1	3 phase fault on the VIOLA 7 (532798) to GEN-2017-086 (589240) 345 kV line CKT 1, near VIOLA 7. a. Apply fault at the VIOLA 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip the generator G17-086-GEN1 (589243)** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9015-3PH	P1	3 phase fault on the VIOLA 7 (532798) to G16-153-TAP (588364) 345 kV line CKT 1, near VIOLA 7. a. Apply fault at the VIOLA 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip the generator G16-153-GEN1 (588363), FR2E2WF1 (533124), FR2E1WF1 (533123), FR2W2WF1 (533126), FR2W1WF1 (533125), FR3WTG1 (578533)** 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.
FLT9016-3PH	P1	3 phase fault on the BUFFALO7 (532782) to KINGMAN7 (532783) 345 kV line CKT 1, near BUFFALO7. a. Apply fault at the BUFFALO7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip the generator K2 WF 1 (534022), K1 WF 1 (534021), P1 WF 1 (534023), N1 WF 1 (534020).** 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.
FLT32-PO1	P6	**PRIOR OUTAGE of the G14-001-TAP (562476) to EMPEC 7 (532768) to 345 kV line CKT 1;** 3 phase fault on the WICHITA7 (532796) to VIOLA 7 (532798) 345 kV line CKT 1, near WICHITA7. a. Apply fault at the WICHITA7 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.
FLT734-PO1	P6	**PRIOR OUTAGE of the G14-001-TAP (562476) to EMPEC 7 (532768) to 345 kV line CKT 1;** 3 phase fault on the WICHITA 121 345 kV (532796) / 138 kV (533040)/ 13.8 kV (532830) XFMR CKT 1, near WICHITA7 (532796) 345 kV. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9010-PO1	P6	**PRIOR OUTAGE of the G14-001-TAP (562476) to EMPEC 7 (532768) to 345 kV line CKT 1;** 3 phase fault on the WICHITA7 (532796) to RENO 7 (532771) 345 kV line CKT 1, near WICHITA7. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9011-PO1	P6	**PRIOR OUTAGE of the G14-001-TAP (562476) to EMPEC 7 (532768) to 345 kV line CKT 1;** 3 phase fault on the WICHITA 7 (532796) to BENTON 7 (532791) 345 kV line CKT 1, near WICHITA 7. a. Apply fault at the WICHITA 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.
FLT9012-PO1	P6	**PRIOR OUTAGE of the G14-001-TAP (562476) to EMPEC 7 (532768) to 345 kV line CKT 1;** 3 phase fault on the WICHITA7 (532796) to BUFFALO7 (532782) 345 kV line CKT 1, near WICHITA7. a. Apply fault at the WICHITA7 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
FLT16-PO2	P6	**PRIOR OUTAGE of the G14-001-TAP (562476) to WICHITA7 (532796) to 345 kV line CKT 1;** 3 phase fault on the EMPEC 7 (532768) to MORRIS 7 (532770) 345 kV line CKT 1, near EMPEC 7. a. Apply fault at the EMPEC 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.
FLT17-PO2	P6	**PRIOR OUTAGE of the G14-001-TAP (562476) to WICHITA7 (532796) to 345 kV line CKT 1;** 3 phase fault on the EMPEC 7 (532768) to SWISVAL7 (532774) 345 kV line CKT 1, near EMPEC 7. a. Apply fault at the EMPEC 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.
FLT9003-PO2	P6	**PRIOR OUTAGE of the G14-001-TAP (562476) to WICHITA7 (532796) to 345 kV line CKT 1;** 3 phase fault on the EMPEC 7 (532768) to READWF 7 (532776) 345 kV line CKT 1, near EMPEC 7. a. Apply fault at the EMPEC 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.
FLT9004-PO2	P6	**PRIOR OUTAGE of the G14-001-TAP (562476) to WICHITA7 (532796) to 345 kV line CKT 1;** 3 phase fault on the EMPEC 7 (532768) to LANG 7 (532769) 345 kV line CKT 1, near EMPEC 7. a. Apply fault at the EMPEC 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.
FLT9005-PO2	P6	**PRIOR OUTAGE of the G14-001-TAP (562476) to WICHITA7 (532796) to 345 kV line CKT 1;** 3 phase fault on the EMP EC 5GUS 345 kV (532768) / 18 kV (532742) XFMR CKT 1, near EMPEC 7 (532768) 345 kV. a. Apply fault at the EMPEC 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer. **Trip the generator EMPEC5 1 (532742)**
FLT1001-SB	P4	**Stuck Breaker on EMPEC 7 (532768) 345kV bus.** a. Apply single-phase fault at EMPEC 7 (532768) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the EMPEC 7 (532768) to LANG 7 (532769) 345 kV line CKT 1. d. Trip the EMP EC 3-4G 345 kV (532768) / 13.8 kV (532741) XFMR CKT 1. **Trip the generator EMPEC341 (532741)**
FLT1002-SB	P4	**Stuck Breaker on EMPEC 7 (532768) 345kV bus.** a. Apply single-phase fault at EMPEC 7 (532768) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the EMPEC 7 (532768) to READWF 7 (532776) 345 kV line CKT 1. d. Trip the EMP EC 5GSU 345 kV (532768) / 18 kV (532742) XFMR CKT 1. **Trip the generator EMPEC5 1 (532742)** **Trip the generator R1 WF 1 (534042)**
FLT1003-SB	P4	**Stuck Breaker on EMPEC 7 (532768) 345kV bus.** a. Apply single-phase fault at EMPEC 7 (532768) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the EMPEC 7 (532768) to MORRIS 7 (532770) 345 kV line CKT 1. d. Trip the EMP EC 7GSU 345 kV (532768) / 18 kV (532744) XFMR CKT 1. **Trip the generator EMPEC7 1 (532744)**
FLT1004-SB	P4	**Stuck Breaker on EMPEC 7 (532768) 345kV bus.** a. Apply single-phase fault at EMPEC 7 (532768) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the EMPEC 7 (532768) to SWISVAL7 (532774) 345 kV line CKT 1. d. Trip the EMP EC 1-2G 345 kV (532768) / 18 kV (532740) XFMR CKT 1. **Trip the generator EMPEC121 (532740)**

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT1005-SB	P4	**Stuck Breaker on EMPEC 7 (532768) 345kV bus.** a. Apply single-phase fault at EMPEC 7 (532768) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the EMPEC 7 (532768) to G14-001-TAP (562476) 345 kV line CKT 1. d. Trip the EMP EC 6GSU 345 kV (532768) / 18 kV (532743) XFMR CKT 1. **Trip the generator EMPEC61 (532743)**
FLT1006-SB	P4	**Stuck Breaker on WICHITA7 (532796) 345kV bus.** a. Apply single-phase fault at WICHITA7 (532796) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the WICHITA 7 (532796) to BENTON 7 (532791) 345 kV line CKT 1 d. Trip the WICHITA7 (532796) to RENO 7 (532771) 345 kV line CKT 1.
FLT1007-SB	P4	**Stuck Breaker on WICHITA7 (532796) 345kV bus.** a. Apply single-phase fault at WICHITA7 (532796) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the WICHITA7 (532796) to G14-001-TAP (562476) 345 kV line CKT 1. d. Trip the WICHI 12 1 345 kV (532796) / 138 kV (533040)/ 13.8 kV (532830) XFMR CKT 1.
FLT1008-SB	P4	**Stuck Breaker on WICHITA7 (532796) 345kV bus.** a. Apply single-phase fault at WICHITA7 (532796) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the WICHITA7 (532796) to BUFFALO7 (532782) 345 kV line CKT 1. d. Trip the WICHI11 1 345 kV (532796) / 138 kV (533040)/ 13.8 kV (532829) XFMR CKT 1.
FLT1009-SB	P4	**Stuck Breaker on WICHITA7 (532796) 345kV bus.** a. Apply single-phase fault at WICHITA7 (532796) on the 345kV bus. b. Wait 16 cycles and remove fault. c. Trip the WICHITA7 (532796) to BUFFALO7 (532782) 345 kV line CKT 2. d. Trip the WICHITA7 (532796) to VIOLA 7 (532798) 345 kV line CKT 1.

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-2014-001 Dynamic Stability Results

Fault ID	25SP			25WP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT10-3PH	Pass	Pass	Stable (2, 3)	Pass	Pass	Stable (2, 3, 6)
FLT11-3PH	Pass	Pass	Stable (2, 3)	Pass	Pass	Stable (2, 3, 6)
FLT12-3PH	Pass	Pass	Stable (2, 3)	Pass	Pass	Stable (2, 3, 6)
FLT16-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT17-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT22-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT27-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT28-3PH	Pass	Pass	Stable (2, 3, 4)	Pass	Pass	Stable (2, 3, 6)
FLT32-3PH	Pass	Pass	Stable (2, 3, 5)	Pass	Pass	Stable (2, 3, 5, 6)
FLT165-3PH	Pass	Pass	Stable (2, 3, 5)	Pass	Pass	Stable (2, 3, 5, 6)
FLT166-3PH	Pass	Pass	Stable (2, 3, 5)	Pass	Pass	Stable (2, 3, 5, 6)
FLT167-3PH	Pass	Pass	Stable (2, 3, 5)	Pass	Pass	Stable (2, 3, 5, 6)
FLT168-3PH	Pass	Pass	Stable (2, 3, 5)	Pass	Pass	Stable (2, 3, 5, 6)
FLT197-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT353-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)

Table 6-2 continued

Fault ID	25SP			25WP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT354-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT355-3PH	Pass	Pass	Stable (1, 2)	Pass	Pass	Stable (1, 2, 3, 6)
FLT356-3PH	Pass	Pass	Stable (2, 3)	Pass	Pass	Stable (2, 3, 6)
FLT459-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT462-3PH	Pass	Pass	Stable (2, 3, 5)	Pass	Pass	Stable (2, 3, 5, 6)
FLT717-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT718-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT719-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT723-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT724-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT726-3PH	Pass	Pass	Stable (2, 3)	Pass	Pass	Stable (2, 3, 6)
FLT727-3PH	Pass	Pass	Stable (2, 3)	Pass	Pass	Stable (2, 3, 6)
FLT731-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT734-3PH	Pass	Pass	Stable (2, 3, 5)	Pass	Pass	Stable (2, 3, 5, 6)
FLT736-3PH	Pass	Pass	Stable (2, 3)	Pass	Pass	Stable (2, 3, 6)
FLT757-3PH	Pass	Pass	Stable (2, 3)	Pass	Pass	Stable (2, 3, 6)
FLT9001-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT9002-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT9003-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT9004-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT9005-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT9006-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT9007-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT9008-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT9009-3PH	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT9010-3PH	Pass	Pass	Stable (2, 3, 5)	Pass	Pass	Stable (2, 3, 5, 6)
FLT9011-3PH	Pass	Pass	Stable (2, 3, 5)	Pass	Pass	Stable (2, 3, 5, 6)
FLT9012-3PH	Pass	Pass	Stable (2, 3, 5)	Pass	Pass	Stable (2, 3, 5, 6)
FLT9013-3PH	Pass	Pass	Stable (2, 3)	Pass	Pass	Stable (2, 3, 6)
FLT9014-3PH	Pass	Pass	Stable (2, 3)	Pass	Pass	Stable (2, 3, 6)
FLT9015-3PH	Pass	Pass	Stable (2, 3)	Pass	Pass	Stable (2, 3, 6)
FLT9016-3PH	Pass	Pass	Stable (2, 3, 5)	Pass	Pass	Stable (2, 3, 5, 6)
FLT32-PO1	Pass	Pass	Stable (2, 3, 5)	Pass	Pass	Stable (2, 3, 5, 6)
FLT734-PO1	Pass	Pass	Stable (2, 3, 5)	Pass	Pass	Stable (2, 3, 5, 6)
FLT9010-PO1	Pass	Pass	Stable (2, 3, 5)	Pass	Pass	Stable (2, 3, 5, 6)
FLT9011-PO1	Pass	Pass	Stable (2, 3, 5)	Pass	Pass	Stable (2, 3, 5, 6)
FLT9012-PO1	Pass	Pass	Stable (2, 3, 5)	Pass	Pass	Stable (2, 3, 5, 6)

Table 6-2 continued

Fault ID	25SP			25WP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT16-PO2	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT17-PO2	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT9003-PO2	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT9004-PO2	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT9005-PO2	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT1001-SB	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT1002-SB	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT1003-SB	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT1004-SB	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT1005-SB	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT1006-SB	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT1007-SB	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT1008-SB	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)
FLT1009-SB	Pass	Pass	Stable (2)	Pass	Pass	Stable (2, 6)

(1) GEN-2017-203 GEN 1 Unit 2 (760812) and GEN 2 Unit 2 (760815) tripped for FLT355-3PH due to frequency relays in both the pre and post modification models
(2) Sustained oscillations were observed at multiple units in both the pre and post modification models
(3) GEN-2017-121 (761841, 761844) did not reach stable active power within 20 seconds in both the pre and post modification models
(4) GEN-2017-009 (532712, 532713, 532714, 532715) did not reach stable active power within 20 seconds in both the pre and post modification models
(5) GEN-2011-008 (539847, 539848, 539852, 539853) did not reach stable active power within 20 seconds in both the pre and post modification models
(6) PRQNW_G_1 (543654) did not reach stable active power within 20 seconds in both the pre and post modification models

The results of the stability analysis showed that GEN-2017-203 GEN 1 Unit 1 (760812) and GEN 2 Unit 2 (760815) tripped with the loss of the the RENFROW7 to G17-185-TAP 345 kV line due to frequency relays. The same tripping was also observed in the DISIS-2017-002 case without the GEN-2014-001 modification. Therefore, the tripping is not attributed to the GEN-2014-001 modification request.

Oscillations were observed for several units under multiple contingencies. For example, similar oscillations were observed for fault FLT16-3PH in the DISIS-2017-002 case without the GEN-2014-001 modification as shown in Figure 6-1 below and with the GEN-2014-001 modification as shown in Figure 6-2 for GEN-2017-119 and GEN-2017-120. Therefore, the oscillations are not attributed to the GEN-2014-001 modification request.

Figure 6-1: FLT16-3PH GEN-2017-119 & GEN-2017-120 Oscillations (25SP DISIS Case)

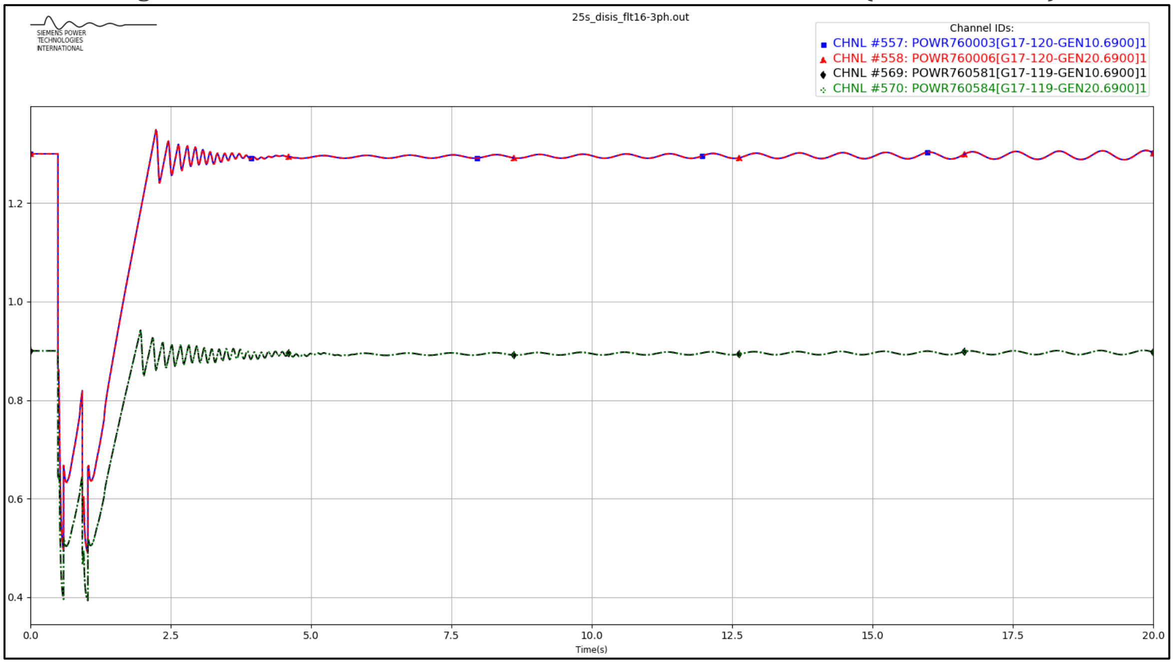
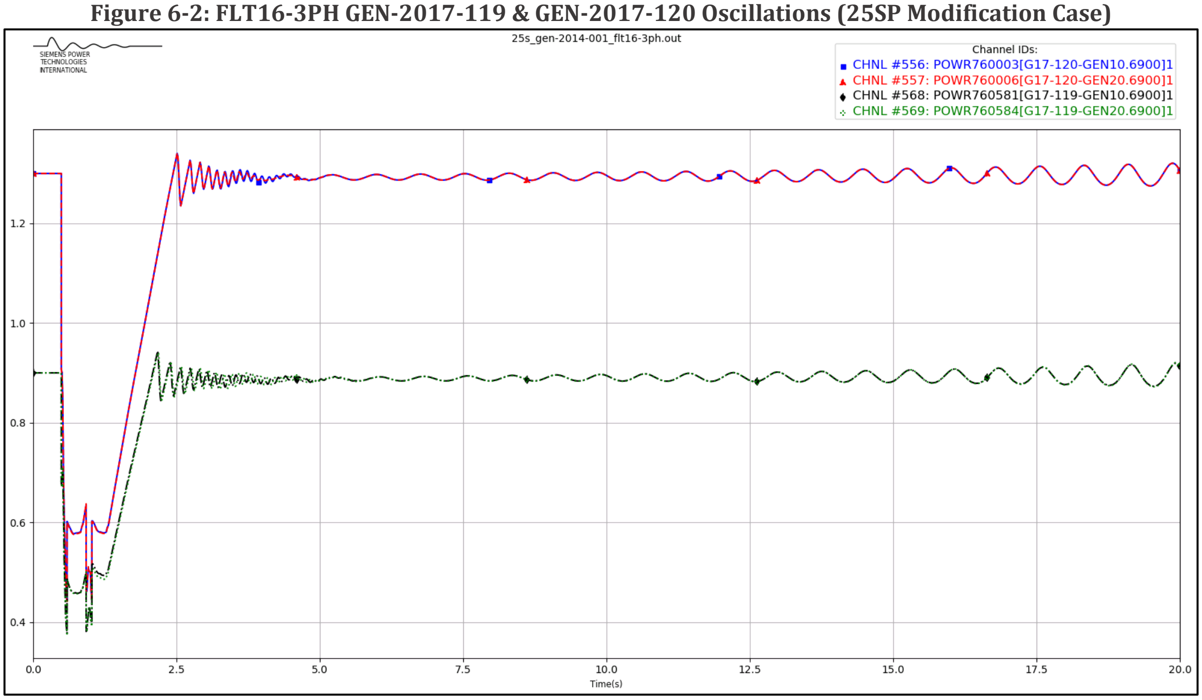


Figure 6-2: FLT16-3PH GEN-2017-119 & GEN-2017-120 Oscillations (25SP Modification Case)



There were also several units including GEN-2011-008, GEN-2017-121, GEN-2017-009, and PRQNW_G_1 did not reach a stable active power within 20 seconds under multiple contingencies. For example, this issue was observed for fault FLT9016-3PH in the DISIS-2017-002 case without the GEN-2014-001 modification as shown in Figure 6-3 below and with the GEN-2014-001 modification as shown in Figure 6-4 for GEN-2011-08. Therefore, this issue was not attributed to the GEN-2014-001 modification request.

Figure 6-3: FLT9016-3PH GEN-2011-008 Active Power (25SP DISIS Case)

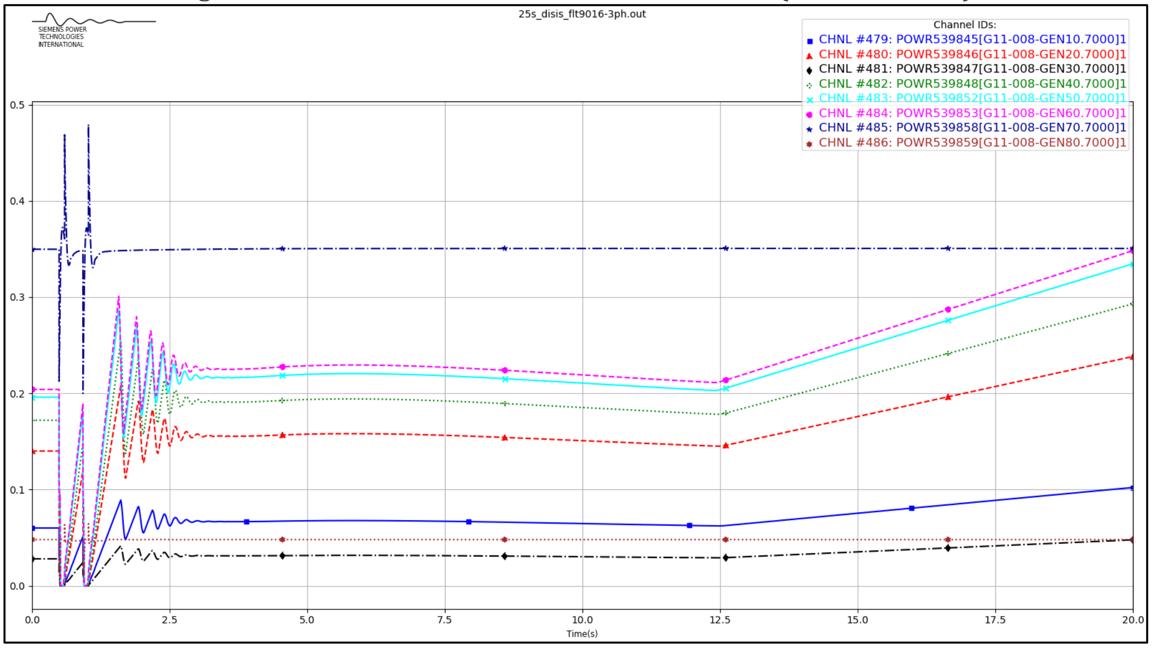
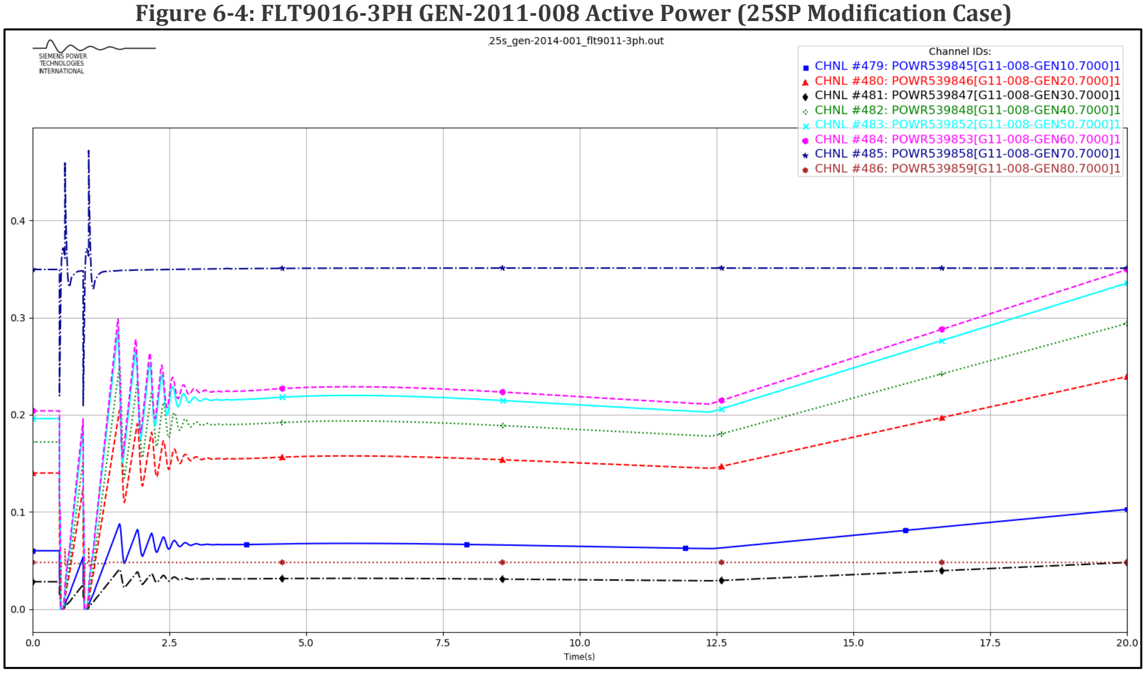


Figure 6-4: FLT9016-3PH GEN-2011-008 Active Power (25SP Modification Case)



There were no damping or voltage recovery violations attributed to the GEN-2014-001 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

The modified generating capacity of GEN-2014-001 (214.32 MW) exceeds the GIA Interconnection Service amount, 200.6 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-2014-001 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-2014-001 requested a Modification Request Impact Study to assess the impact of the turbine and facility change to 76 x GE 2.82 MW for a total capacity of 214.32 MW. This generating capacity for GEN-2014-001 (214.32 MW) exceeds its Generator Interconnection Agreement (GIA) Interconnection Service amount, 200.6 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. The requested modification includes the use of a Power Plant Controller (PPC) to limit the total power injected into the POI.

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

SPP determined that power flow should not be performed based on the POI MW injection increase of 1.04% compared to the DISIS-2017-002 power flow models. However, SPP determined that while the modification used the same turbine manufacturer, GE, the change in stability model from GEWTGCU1 to REGCA1 required short circuit and dynamic stability 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-2014-001 project needed a 28.3 MVAr shunt reactor on the 34.5 kV bus of the project substation with the modifications in place, an increase from the 21.2 MVAr found for the previous modification study[4]. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind or no-wind conditions. The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

The 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-2014-001 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2014-001 POI was no greater than 0.98 kA. All three-phase fault current levels within 5 buses of the POI with the GEN-2014-001 generators online were below 44 kA. There were several buses with a maximum fault current of over 40 kA. These buses are highlighted in Appendix B.

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.

[4] GEN-2014-001 Impact Restudy for Generator Modification, January 2020

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-2014-001 modification. These were not attributed to the GEN-2014-001 modification request.

1. GEN-2017-203 GEN 1 Unit 1 (760812) and GEN 2 Unit 2 (760815) tripped with the loss of the RENFROW7 to G17-185-TAP 345 kV line due to frequency relays.
2. Oscillations were observed for several units including GEN-2015-052, GEN-2017-082, GEN-2017-005, GEN-2017-119, and GEN-2017-120 under multiple contingencies.
3. Several units including GEN-2011-008, GEN-2017-121, GEN-2017-009, and PRQNW_G_1 did not reach a stable active power within 20 seconds under multiple contingencies.

There were no damping or voltage recovery violations attributed to the GEN-2014-001 project observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

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

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

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

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