Report on

GEN-2015-025
Modification Request Impact Study

Revision R1 **May 8, 2024**

Submitted to
Southwest Power Pool

SPP Southwest Power Pool

anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
5/6/2024	Aneden Consulting	Initial Report Issued

Executive Summary

Aneden Consulting (Aneden) was retained by Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2015-025, an active Generation Interconnection Request (GIR) with a Point of Interconnection (POI) on the Thistle to Wichita 345 kV Double Circuit (Buffalo Flats 345 kV).

The GEN-2015-025 project interconnects in the Evergy, formerly known as Westar Energy (WERE), control area with a capacity of 220 MW. This Study has been requested to evaluate the modification of GEN-2015-025 to change the configuration to 104 x GE 1.79 MW (Derated to 1.715 MW) + 7 x GE 1.79 MW + 9 x GE 1.79 MW (Uprated to 1.85 MW) wind turbines for a total dispatch of 207.54 MW.

In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformers, and generation interconnection line. The existing and modified configurations for GEN-2015-025 are shown in Table ES-1 below.

SPP determined that steady-state analysis was not required because the modifications to the project were not significant enough to change the previously studied steady-state conclusions. However, SPP determined that while the modification used the same turbine manufacturer, GE, the change in stability model from GEWTGCU1 to REGCAU1 required short circuit and dynamic stability analyses.

The scope of this study included reactive power analysis, short circuit analysis, and dynamic stability analysis.

Aneden performed the analyses using the modification request data and the DISIS-2018-002/19-001 study models:

- 2025 Summer Peak (25SP),
- 2025 Winter Peak (25WP)

Table ES-1: GEN-2015-025 Modification Request

Facility	Existing Configuration		Modification Configuration	
Point of Interconnection	Tap on Thistle 345 kV (539801) to Wichita 345 kV (532796) Double Circuit (Buffalo Flats 345 kV 532782)		Tap on Thistle 345 kV (539801) to Wichita 345 kV (532796) Double Circuit (Buffalo Flats 345 kV 532782)	
Configuration/Capacity	110 x GE 1.8 MW + 10 x GE 1.79 MW = 215.9 MW (wind)		104 x GE 1.79 MW (Derated to 1.715 MW) + 7 x GE 1.79 MW + 9 x GE 1.79 MW (Uprated to 1.85 MW) = 207.54 MW (wind)	
Generation Interconnection Line	Shared with GEN-2015-024 & GEN-2019-001: Length = 46.2 miles R = 0.001490 pu X = 0.020960 pu B = 0.436110 pu Rating MVA = 1335.7 MVA		Shared with GEN-2015-024 & GEN-2019-001: Length = 46.2 miles R = 0.001487 pu X = 0.020962 pu B = 0.436110 pu Rating MVA = 1165 MVA	
Main Substation Transformer[1]	X12 = 14.493% R12 = 0.242%, X23 = 2.652% R23 = 0.205%, X13 = 12.637% R13 = 0.282%, Winding 1-2 MVA = 130 MVA, Winding 2-3 & 3-1 MVA = 78 MVA, Winding 1 & 2 Rating MVA = 130 MVA Winding 3 Rating MVA = 43.3 MVA	X12 = 14.57% R12 = 0.239%, X23 = 2.652% R23 = 0.205%, X13 = 12.637% R13 = 0.282%, Winding 1-2 MVA = 130 MVA, Winding 2-3 & 3-1 MVA = 78 MVA, Winding 1 & 2 Rating MVA = 130 MVA Winding 3 Rating MVA = 43.3 MVA	X = 8.5%, R = 0.15%, Winding MVA = 78 MVA, Rating MVA = 130 MVA	X = 8.5%, R = 0.15%, Winding MVA = 78 MVA, Rating MVA = 130 MVA
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 60 X = 5.63%, R = 0.57%, Winding MVA = 99 MVA, Rating MVA = 99 MVA	Gen 2 Equivalent Qty: 60 X = 5.71%, R = 0.57%, Winding MVA = 108 MVA, Rating MVA = 108 MVA	Gen 1 Equivalent Qty: 60 X = 5.699%, R = 0.76%, Winding MVA = 108.36 MVA, Rating MVA[2] = 108.4 MVA	Gen 2 Equivalent Qty: 60 X = 5.699%, R = 0.76%, Winding MVA = 108.18 MVA, Rating MVA[2] = 108.2 MVA
Equivalent Collector Line[3]	R = 0.008490 pu X = 0.012690 pu B = 0.058120 pu	R = 0.021000 pu X = 0.036970 pu B = 0.112930 pu	R = 0.005019 pu X = 0.009201 pu B = 0.061277 pu	R = 0.005023 pu X = 0.009195 pu B = 0.061277 pu
Generator Dynamic Model[4] & Power Factor	55 x GE 1.8 MW + 5 x GE 1.79 MW (GEWTGCU1)[4] Leading: 0.95 Lagging: 0.95	55 x GE 1.8 MW + 5 x GE 1.79 MW (GEWTGCU1)[4] Leading: 0.95 Lagging: 0.95	49 x GE 1.715 MW + 5 x GE 1.79 MW + 6 x GE 1.85 MW (REGCAU1)[4] Leading: 0.9 Lagging: 0.9	55 x GE 1.715 MW + 2 x GE 1.79 MW + 3 x GE 1.85 MW (REGCAU1)[4] Leading: 0.9 Lagging: 0.9
Reactive Power Devices	1 x 15 MVAR 34.5 kV Reactor	1 x 15 MVAR 34.5 kV Reactor	1 x 15 MVAR 34.5 kV Reactor	1 x 15 MVAR 34.5 kV Reactor

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

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

The results of the reactive power analysis using the 25SP model showed that the GEN-2015-025 project needed a 59.5 MVAr shunt reactor on the 34.5 kV bus of the project substation with the modifications in place, an increase from the 57.1 MVAr found for the combined GEN-2015-024 and GEN-2015-025 projects

[1] Power System Simulator for Engineering

in the DISIS-2015-001 study[2].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 reactive power analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator (TOP). The applicable reactive power requirements will be further reviewed by the TO and/or TOP.

The short circuit analysis was performed using the 25SP stability model modified for short circuit analysis. The results from the short circuit analysis with the updated topology showed that the maximum GEN-2015-025 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2015-025 POI was 0.73 kA. The maximum three-phase fault current level within 5 buses of the POI was 32.2 kA for the 25SP model.

The dynamic stability analysis was performed using Siemens PTI PSS/E version 34.8.0 software for the two modified study models: 25SP and 25WP. 50 events were simulated, which included three-phase faults and single-line-to-ground stuck breaker faults.

The results of the dynamic stability analysis showed several existing base case issues that were found in both the original DISIS-2018-002/19-001 model and in the model with the GEN-2015-025 modification included. These issues were not attributed to the GEN-2015-025 modification request and are detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2015-025 modification request observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

Based on the results of the study, SPP determined that the requested modification is **not 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.

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.

[2] Definitive Interconnection System Impact Study for Generation Interconnection Requests (DISIS-2015-001) – August 2015

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-2015-025. A Modification Request Impact Study is a generation interconnection study performed to evaluate the impacts of modifying the DISIS study assumptions. The determination of the required scope of the study is dependent upon the specific modification requested and how it may impact the results of the DISIS study. Impacting the DISIS results could potentially affect the cost or timing of any Interconnection Request with a later Queue priority date, deeming the requested modification a Material Modification. The criteria sections below include reasoning as to why an analysis was either included or excluded from the scope of study.

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

1.1 Reactive Power Analysis

SPP requires that a reactive power analysis be performed on the requested configuration if it is a non-synchronous resource. The reactive power analysis determines the capacitive effect at the POI caused by the project's collection system and transmission line's capacitance. A shunt reactor size was determined to offset the capacitive effect and maintain zero (0) MVAr injection at the POI while the plant's generators and capacitors were offline.

1.2 Short Circuit Analysis & Stability Analysis

To determine whether stability and short circuit analyses are required, SPP evaluates the difference between the stability models, 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 Steady-State Analysis

Steady-state analysis is performed if SPP deems it necessary based on the nature of the requested change. SPP determined that steady-state analysis was not required because the modifications to the project were not significant enough to change the previously studied steady-state conclusions.

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-2015-025 Interconnection Customer requested a modification to its Generation Interconnection Request (GIR) with a Point of Interconnection (POI) on the Thistle to Wichita 345 kV Double Circuit (Buffalo Flats 345 kV) in the Evergy, formerly known as Westar Energy (WERE), control area.

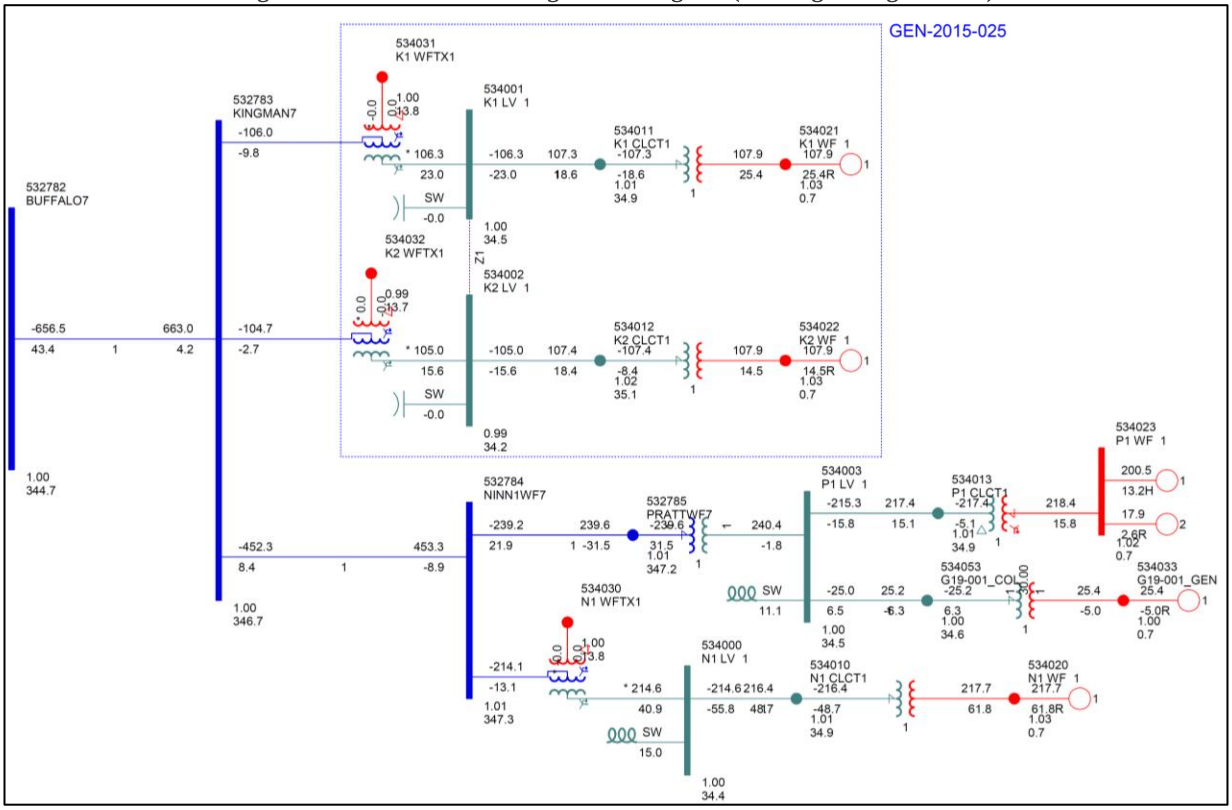
At the time of report posting, GEN-2015-025 is an active Interconnection Request with a queue status of "IA FULLY EXECUTED/COMMERCIAL OPERATION." GEN-2015-025 is a wind facility with a maximum summer and winter queue capacity of 220 MW with Energy Resource Interconnection Service (ERIS).

The GEN-2015-025 project is currently in the DISIS-2015-001 cluster. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2015-025 configuration using the DISIS-2018-002/19-001 25SP stability model.

This Study has been requested to evaluate the modification of GEN-2015-025 to change the configuration to 104 x GE 1.79 MW (Derated to 1.715 MW) + 7 x GE 1.79 MW + 9 x GE 1.79 MW (Uprated to 1.85 MW) wind turbines for a total dispatch of 207.54 MW.

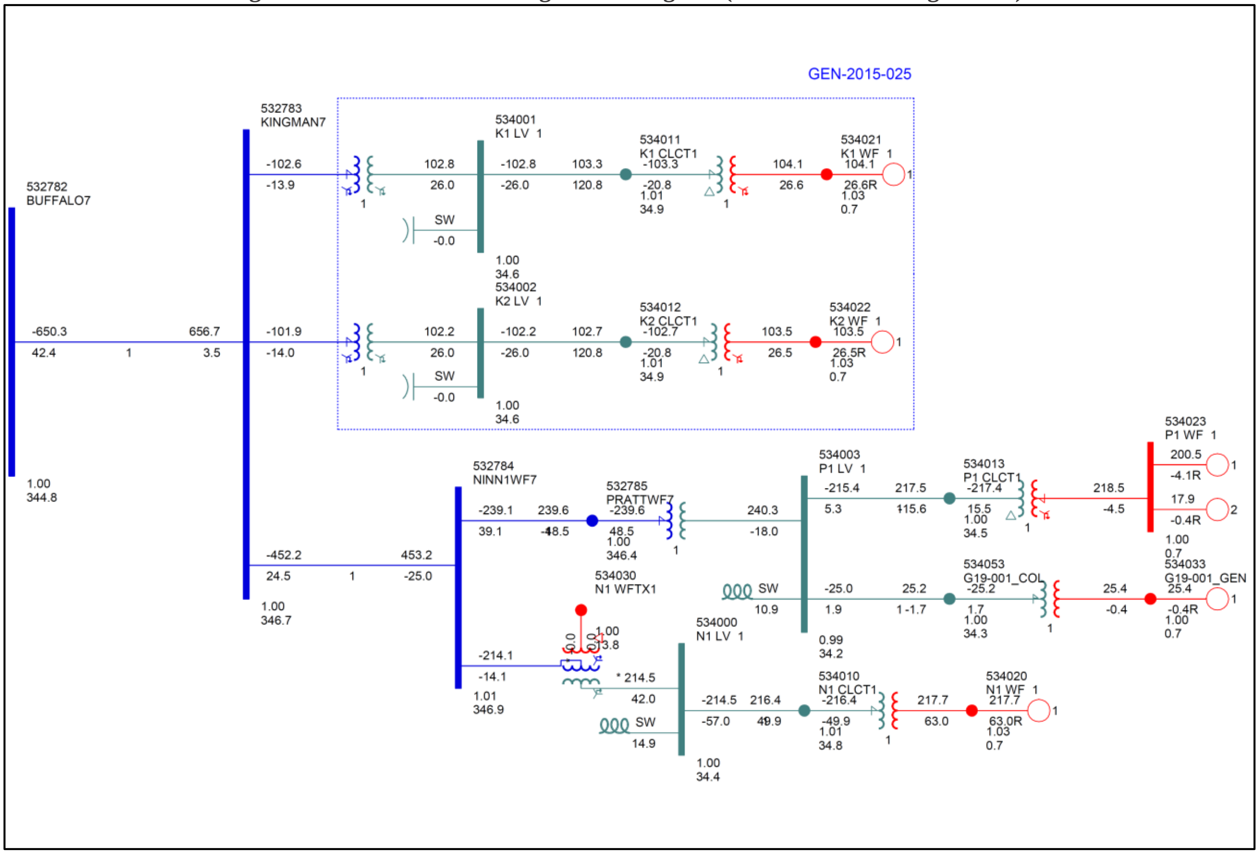
In addition, the modification request included changes to the collection system, generator step-up transformers, main substation transformers, and generation interconnection line. Figure 2-2 shows the power flow model single line diagram for the GEN-2015-025 modification. The existing and modified configurations for GEN-2015-025 are shown in Table 2-1 below.

Figure 2-1: GEN-2015-025 Single Line Diagram (Existing Configuration*)



*based on the DISIS-2018-002/19-001 25SP stability models

Figure 2-2: GEN-2015-025 Single Line Diagram (Modification Configuration)



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Generation Interconnection Line	<u>Shared with GEN-2015-024 & GEN-2019-001:</u> Length = 46.2 miles R = 0.001490 pu X = 0.020960 pu B = 0.436110 pu Rating MVA = 1335.7 MVA		<u>Shared with GEN-2015-024 & GEN-2019-001:</u> Length = 46.2 miles R = 0.001487 pu X = 0.020962 pu B = 0.436110 pu Rating MVA = 1165 MVA	
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Reactive Power Devices	1 x 15 MVAR 34.5 kV Reactor	1 x 15 MVAR 34.5 kV Reactor	1 x 15 MVAR 34.5 kV Reactor	1 x 15 MVAR 34.5 kV Reactor

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-2018-002/19-001 study models. The analysis was completed using PSS/E version 34 software.

The methodology and results of the comparisons are described below.

3.1 Stability Model Parameters Comparison

SPP determined that while the modification used the same turbine manufacturer, GE, the change in stability model from GEWTGCU1 to REGCAU1 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 stability model parameters comparison was not needed for the determination of the scope of the study.

3.2 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 Reactive Power Analysis

The reactive power analysis was performed for GEN-2015-025 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-2015-024 and GEN-2019-001 projects that shares the gen-tie line were disconnected. The GEN-2015-025 generators and capacitors were switched out of service while other system elements remained in-service. Shunt reactors were tested at the project's collection substation 34.5 kV buses to set the MVAr flow into the POI to approximately zero. The size of the shunt reactors was 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 reactive power analysis using the modification request data based on the 25SP DISIS-2018-002/19-001 stability study model.

4.2 Results

The results from the analysis showed that the GEN-2015-025 project needed approximately 59.5 MVAr of total compensation at its collector substations to reduce the POI MVAr to zero. This is an increase from the 57.1 MVAr found for the combined GEN-2015-024 and GEN-2015-025 projects in the DISIS-2015-001 study[3]. The final shunt reactor requirements are shown in Table 4-1. Figure 4-1 illustrates the shunt reactor sizes needed to reduce the POI MVAr to approximately zero with the updated topology.

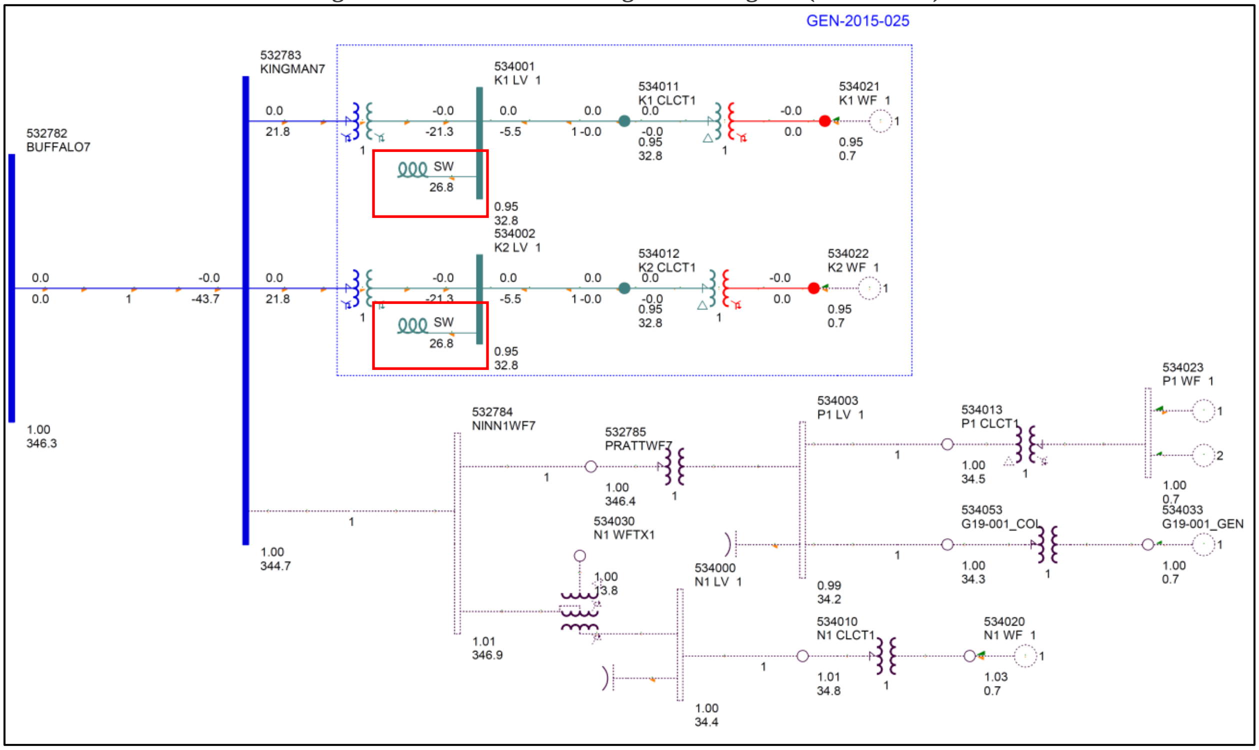
The information gathered from the reactive power analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator (TOP). The applicable reactive power requirements will be further reviewed by the TO and/or TOP.

Table 4-1: Shunt Reactor Size for Reactive Power Analysis

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)
			25SP
GEN-2015-025	532782	BUFFALO7	59.5

[3] Definitive Interconnection System Impact Study for Generation Interconnection Requests (DISIS-2015-001) – August 2015

Figure 4-1: GEN-2015-025 Single Line Diagram (Shunt Sizes)



5.0 Short Circuit Analysis

Aneden performed a short circuit study using the 25SP model for GEN-2015-025 to determine the maximum fault current requiring interruption by protective equipment for each bus in the relevant subsystem. 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-2015-025 online.

Aneden created a short circuit model using the 25SP DISIS-2018-002/19-001 stability study model by adjusting the GEN-2015-025 short circuit parameters consistent with the submitted data. The adjusted parameters used in the short circuit analysis are shown in Table 5-1 below. No other changes were made to the model.

Table 5-1: Short Circuit Model Parameters*

Parameter	Value by Generator Bus#	Value by Generator Bus#
	534021	534022
Machine MVA Base	119.74	119.54
R (pu)	0.0	0.0
X'' (pu)	0.2	0.2

*pu values based on Machine MVA Base

5.2 Results

The results of the short circuit analysis for the 25SP model are summarized in Table 5-2 and Table 5-3. The GEN-2015-025 POI bus (Buffalo Flats 345 kV) fault current magnitudes for the comparison cases are provided in Table 5-2 showing a fault current of 20.67 kA with the GEN-2015-025 project online. Table 5-3 shows the maximum fault current magnitudes and fault current increases with the GEN-2015-025 project online.

The maximum fault current calculated within 5 buses of the POI was 32.2 kA for the 25SP model. The maximum GEN-2015-025 contribution to three-phase fault currents was about 3.7% and 0.73 kA[4].

Table 5-2: POI Short Circuit Comparison Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	kA Change	%Change
25SP	19.95	20.67	0.73	3.7%

[4] For buses not on the generation interconnection line

Table 5-3: 25SP Short Circuit Comparison Results[5]

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	19.6	0.04	0.2%
115	21.9	0.06	0.3%
138	32.2	0.27	0.9%
161	29.2	0.00	0.0%
230	21.6	0.01	0.1%
345	31.7	0.73	3.7%
MAX	**32.2**	**0.73**	**3.7%**

[5] For buses not on the generation interconnection line

6.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the modifications to GEN-2015-025. The analysis was performed according to SPP's Disturbance Performance Requirements[6]. The modification details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix A. The existing base case issues and simulation plots can be found in Appendix C.

6.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested GEN-2015-025 configuration of 104 x GE 1.79 MW (Derated to 1.715 MW) + 7 x GE 1.79 MW + 9 x GE 1.79 MW (Uprated to 1.85 MW) (all units are using REGCAU1). This stability analysis was performed using Siemens PTI's PSS/E version 34.8.0 software.

The modifications requested for the GEN-2015-025 project were used to create modified stability models for this impact study based on the DISIS-2018-002/19-001 stability study models:

- 2025 Summer Peak (25SP),
- 2025 Winter Peak (25WP)

The dynamic model data for the GEN-2015-025 project is provided in Appendix A. The 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 adjustment was made to address existing base case issues that are not attributed to the modification request:

- The fault simulation file acceleration factor was reduced and the iteration limit was increased as needed to resolve stability simulation crashes.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2015-025 and other current and prior queued projects in Group 3. In addition, voltages of five (5) buses away from the POI of the GEN-2015-025 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within the study areas including 327 (EES-EAI), 330 (AECI), 356 (AMMO), 515 (SWPA), 520 (AEPW), 523 (GRDA), 524 (OKGE), 525 (WFEC), 526 (SPS), 531 (MIDW), 534 (SUNC), 536 (WERE), 541 (KCPL), 542 (KACY), 544 (EMDE), 545 (INDN), 546 (SPRM), 635 (MEC), 640 (NPPD), and 645 (OPPD) were monitored. The voltages of all 100 kV and above buses within the study area were monitored as well.

6.2 Fault Definitions

Aneden simulated the nearby faults previously simulated in the DISIS-2018-002/19-001 study and developed additional fault events as required. The new set of faults was simulated using the modified study models. The fault events included three-phase faults and single-line-to-ground stuck breaker faults. Single-line-to-ground faults are approximated by applying a fault impedance to bring the faulted bus positive sequence voltage to 0.6 pu. The simulated faults are listed and described in Table 6-1 below. These contingencies were applied to the modified 25SP and 25WP models.

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

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT17-3PH	P1	3 phase fault on the CLARKCOUNTY7 (539800) to G16-046-TAP (560080) 345 kV line CKT 1, near CLARKCOUNTY7. a. Apply fault at the CLARKCOUNTY7 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.
FLT18-3PH	P1	3 phase fault on the CLARKCOUNTY7 (539800) to TRANSFORMER (539813) 345 kV line CKT 1, near CLARKCOUNTY7. a. Apply fault at the CLARKCOUNTY7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generators on bus WTGLVB (539814) 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.
FLT19-3PH	P1	3 phase fault on the CLARKCOUNTY7 (539800) to THISTLE7 (539801) 345 kV line CKT 1, near CLARKCOUNTY7. a. Apply fault at the CLARKCOUNTY7 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.
FLT21-3PH	P1	3 phase fault on the CLARKCOUNTY7 (539800) to GEN-2011-008 (539840) 345 kV line CKT 1, near CLARKCOUNTY7. a. Apply fault at the CLARKCOUNTY7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generators on bus G11-008-GEN4 (539848), G11-008-GEN3 (539847), G11-008-GEN1 (539845), G11-008-GEN2 (539846), G11-008-GEN5 (539852), G11-008-GEN6 (539853), G11-008-GEN8 (539859), G11-008-GEN7 (539858) 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 CLARKCOUNTY7 (539800) to GEN-2019-058 (763890) 345 kV line CKT 1, near CLARKCOUNTY7. a. Apply fault at the CLARKCOUNTY7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generators on bus G19-063-GEN1 (763926), G19-058-GEN2 (763895), G19-058-GEN1 (763893) 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.
FLT46-3PH	P1	3 phase fault on the THISTLE7 (539801) to CLARKCOUNTY7 (539800) 345 kV line CKT 1, near THISTLE7. a. Apply fault at the THISTLE7 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.
FLT48-3PH	P1	3 phase fault on the THISTLE7 (539801) to GEN-2018-049 (762834) 345 kV line CKT 1, near THISTLE7. a. Apply fault at the THISTLE7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generators on bus G18-108-GEN1 (763287), G18-049-GEN1 (762837) 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.
FLT49-3PH	P1	3 phase fault on the THISTLE7 (539801) to GEN-2017-018 (588630) 345 kV line CKT 1, near THISTLE7. a. Apply fault at the THISTLE7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. Trip generators on bus G17-018-GEN1 (588633), G14-001-GEN2 (588637) 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.
FLT50-3PH	P1	3 phase fault on the THISTLE7 (539801) to DGRASSE7 (515852) 345 kV line CKT 1, near THISTLE7. a. Apply fault at the THISTLE7 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
FLT52-3PH	P1	3 phase fault on the THISTLE7 (539801) to BUFFALO7 (532782) 345 kV line CKT 1, near THISTLE7. a. Apply fault at the THISTLE7 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.
FLT54-3PH	P1	3 phase fault on the THISTLE 345 kV (539801) /138 kV (539804) /13.8 kV (539802) XFMR CKT 1, near THISTLE7 345 kV. a. Apply fault at the THISTLE7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT57-3PH	P1	3 phase fault on the DGRASSE7 (515852) to THISTLE7 (539801) 345 kV line CKT 1, near DGRASSE7. a. Apply fault at the DGRASSE7 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.
FLT59-3PH	P1	3 phase fault on the DGRASSE7 (515852) to WWRDEHV7 (515375) 345 kV line CKT 1, near DGRASSE7. a. Apply fault at the DGRASSE7 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.
FLT61-3PH	P1	3 phase fault on the DGRASSE7 345 kV (515852) /138 kV (515853) /13.8 kV (515854) XFMR CKT 1, near DGRASSE7 345 kV. a. Apply fault at the DGRASSE7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT75-3PH	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.
FLT77-3PH	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.
FLT80-3PH	P1	3 phase fault on the BUFFALO7 (532782) to GEN-2017-220 (760284) 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 generators on bus G17-221-GEN1 (760307), G17-220-GEN1 (760287) 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.
FLT81-3PH	P1	3 phase fault on the BUFFALO7 (532782) to GEN-2016-073 (587500) 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 generators on bus G16-073-GEN1 (587503) 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.
FLT88-3PH	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.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT89-3PH	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.
FLT90-3PH	P1	3 phase fault on the WICHITA7 (532796) to BENTON 7 (532791) 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.
FLT91-3PH	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.
FLT92-3PH	P1	3 phase fault on the WICHITA 121 345 kV (532796) /138 kV (533040) /13.8 kV (532829) XFMR CKT 1, near WICHITA7 345 kV. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT93-3PH	P1	3 phase fault on the WICHITA 121 345 kV (532796) /138 kV (533040) /13.8 kV (532830) XFMR CKT 1, near WICHITA7 345 kV. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT1051-3PH	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.
FLT1052-3PH	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.
FLT1054-3PH	P1	3 phase fault on the BENTON 345 kV (532791) /138 kV (532986) /13.8 kV (532821) XFMR CKT 1, near BENTON 7 345 kV. a. Apply fault at the BENTON 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT1055-3PH	P1	3 phase fault on the BENTON 345 kV (532791) /138 kV (532986) /13.8 kV (532822) XFMR CKT 1, near BENTON 7 345 kV. a. Apply fault at the BENTON 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT1067-3PH	P1	3 phase fault on the RENO 345 kV (532771) /115 kV (533416) /14.4 kV (532810) XFMR CKT 1, near RENO 7 345 kV. a. Apply fault at the RENO 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT1068-3PH	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.

Table 6-1 Continued

Fault ID	Planning Event	Fault Descriptions
FLT1070-3PH	P1	3 phase fault on the G14-001-TAP (562476) to EMPEC 7 (532768) 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.
FLT1071-3PH	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 generators on bus 589243 Trip generators on bus 588363 Trip generators on bus 533125 Trip generators on bus 578533 Trip generators on bus 533126 Trip generators on bus 533123 Trip generators on bus 533124 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.
FLT1073-3PH	P1	3 phase fault on the VIOLA 7 (532798) to G18-128-TAP (763421) 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.
FLT1075-3PH	P1	3 phase fault on the VIOLA 345 kV (532798) /138 kV (533075) /13.8 kV (532832) XFMR CKT 1, near VIOLA 7 345 kV. a. Apply fault at the VIOLA 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT1096-3PH	P1	3 phase fault on the VIOLA 7 (532798) to WICHITA7 (532796) 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.
FLT1098-3PH	P1	3 phase fault on the G18-128-TAP (763421) to VIOLA 7 (532798) 345 kV line CKT 1, near G18-128-TAP. a. Apply fault at the G18-128-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.
FLT1149-3PH	P1	3 phase fault on the G14-001-TAP (562476) to GEN-2014-001 (583850) 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. Trip generators on bus G14-001-GEN1 (583853), G14-001-GEN2 (583856) 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.
FLT1258-3PH	P1	3 phase fault on the ROSEHIL7 (532794) to BENTON 7 (532791) 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.
FLT1280-3PH	P1	3 phase fault on the RENO 345 kV (532771) /115 kV (533416) /14.4 kV (532807) XFMR CKT 1, near RENO 7 345 kV. a. Apply fault at the RENO 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
FLT611-SB	P4	**Stuck Breaker at BUFFALO7 (532782) 345 kV bus** a. Apply single phase fault at BUFFALO7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the BUFFALO7 (532782) to WICHITA7 (532796) 345 kV line CKT 1. d. Trip the BUFFALO7 (532782) to THISTLE7 (539801) 345 kV line CKT 1.
FLT9010-3PH	P1	3 phase fault on the VIOLA 345 kV (532798) /138 kV (533075) /13.8 kV (999532) XFMR CKT 1, near VIOLA 7 345 kV. a. Apply fault at the VIOLA 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9026-3PH	P1	3 phase fault on the CLARKCOUNTY7 (539800) to SPERVIL7 (531469) 345 kV line CKT 1, near CLARKCOUNTY7. a. Apply fault at the CLARKCOUNTY7 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.
FLT1001-SB	P4	**Stuck Breaker at WICHITA7 (532796) 345 kV bus** a. Apply single phase fault at WICHITA7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the WICHITA7 (532796) to RENO 7 (532771) 345 kV line CKT 1. d. Trip the WICHITA7 (532796) to BENTON 7 (532791) 345 kV line CKT 1.
FLT1002-SB	P4	**Stuck Breaker at WICHITA7 (532796) 345 kV bus** a. Apply single phase fault at WICHITA7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the WICHITA7 (532796) to BUFFALO7 (532782) 345 kV line CKT 1. d. Trip the WICHITA7 (532796) to VIOLA 7 (532798) 345 kV line CKT 1.
FLT1003-SB	P4	**Stuck Breaker at WICHITA7 (532796) 345 kV bus** a. Apply single phase fault at WICHITA7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the WICHITA7 (532796) to BUFFALO7 (532782) 345 kV line CKT 2. d. Trip the WICHITA 121 345 kV (532796) /138 kV (533040) /13.8 kV (532830) XFMR CKT 1.
FLT1004-SB	P4	**Stuck Breaker at WICHITA7 (532796) 345 kV bus** a. Apply single phase fault at WICHITA7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the WICHITA7 (532796) to G14-001-TAP (562476) 345 kV line CKT 1. d. Trip the WICHITA 121 345 kV (532796) /138 kV (533040) /13.8 kV (532829) XFMR CKT 1.
FLT1005-SB	P4	**Stuck Breaker at THISTLE7 (539801) 345 kV bus** a. Apply single phase fault at THISTLE7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the THISTLE7 (539801) to CLARKCOUNTY7 (539800) 345 kV line CKT 1. d. Trip the THISTLE7 (539801) to DGRASSE7 (515852) 345 kV line CKT 1.
FLT1006-SB	P4	**Stuck Breaker at THISTLE7 (539801) 345 kV bus** a. Apply single phase fault at THISTLE7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the THISTLE7 (539801) to CLARKCOUNTY7 (539800) 345 kV line CKT 2. d. Trip the THISTLE7 (539801) to BUFFALO7 (532782) 345 kV line CKT 2.
FLT1007-SB	P4	**Stuck Breaker at THISTLE7 (539801) 345 kV bus** a. Apply single phase fault at THISTLE7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the THISTLE 345 kV (539801) /138 kV (539804) /13.8 kV (539802) XFMR CKT 1. d. Trip the THISTLE7 (539801) to BUFFALO7 (532782) 345 kV line CKT 1.
FLT1008-SB	P4	**Stuck Breaker at BUFFALO7 (532782) 345 kV bus** a. Apply single phase fault at BUFFALO7 bus. b. Clear fault after 16 cycles and trip the following elements c. Trip the BUFFALO7 (532782) to GEN-2017-220 (760284) 345 kV line CKT 1. d. Trip the BUFFALO7 (532782) to THISTLE7 (539801) 345 kV line CKT 2. **Trip generators on bus G17-221-GEN1 (760307), G17-220-GEN1 (760287)**

6.3 Results

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

Table 6-2: GEN-2015-025 Dynamic Stability Results

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT17-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT18-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT19-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT21-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT22-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT46-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT48-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT49-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT50-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT52-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT54-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT57-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT59-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT61-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT75-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT77-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT80-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT81-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT88-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT89-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT90-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT91-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT92-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT93-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1051-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1052-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1054-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1055-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1067-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1068-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1070-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1071-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1073-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1075-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1096-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1098-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1149-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1258-3PH	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	25SP			25WP		
	Voltage Violation	Voltage Recovery	Stable	Voltage Violation	Voltage Recovery	Stable
FLT1280-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT611-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT9026-3PH	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable

The results of the dynamic stability showed several existing base case issues that were found in both the original DISIS-2018-002/19-001 model and the model with the GEN-2015-025 modification included. These issues were not attributed to the GEN-2015-025 modification request and detailed in Appendix C.

There were no damping or voltage recovery violations attributed to the GEN-2015-025 modification request observed during the simulated faults. Additionally, the project was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

7.0 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.

7.1 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 steady-state conclusions.

This determination implies that any network upgrades already required by GEN-2015-025 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.