Submitted to
Southwest Power Pool

Report On

GEN-2016-176
Modification Request Impact Study

Revision R1

Date of Submittal
October 28, 2021

anedenconsulting.com

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Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
10/28/2021	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-2016-176, an active Generation Interconnection Request (GIR) with a point of interconnection (POI) at the Stranger Creek 345 kV Substation.

The GEN-2016-176 project is proposed to interconnect in the Westar Energy (WERE) control area with a capacity of 302 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2016-176 to change the turbine configuration to 8 x GE 2.32 MW + 100 x 2.82 MW for a total generating capacity of 300.56 MW.

In addition, the modification request included changes to the collection system, generator step-up transformers, generation interconnection line, and main substation transformer. The existing and modified configurations for GEN-2016-176 are shown in Table ES-2 and Table ES-3 respectively.

Table ES-1: GEN-2016-176 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2016-176	Stranger Creek 345 kV (532772)	151 x GE 2.0 MW	302

Table ES-2: GEN-2016-176 Existing Configuration Details

<table>
<tr><th>Facility</th><th colspan="4">Existing</th></tr>
<tr><td>Point of Interconnection</td><td colspan="4">Stranger Creek 345 kV (532772)</td></tr>
<tr><td>Configuration/Capacity</td><td colspan="4">151 x GE 2.0 MW = 302 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td><u>Stranger Creek to GEN-2016-149:</u>
Length = 38 miles*
R = 0.001209 pu*
X = 0.017664 pu*
B = 0.348080 pu*
Line Rating = 1084 MVA*</td><td><u>GEN-2016-149 to GEN-2016-174:</u>
Length = 38 miles*
R = 0.001209 pu*
X = 0.017664 pu*
B = 0.348080 pu*
Line Rating = 1084 MVA*</td><td><u>GEN-2016-174 to GEN-2016-176:</u>
Length = 37 miles
R = 0.001221 pu
X = 0.017390 pu
B = 0.339882 pu
Line Rating = 0 MVA</td><td><u>GEN-2016-176 to GEN-2016-150:</u>
Length = 37 miles
R = 0.001221 pu
X = 0.017390 pu
B = 0.339882 pu
Line Rating = 0 MVA</td></tr>
<tr><td>Main Substation Transformer[1]</td><td colspan="4"><u>345/34.5 kV Transformer:</u>
X = 8.997% R = 0.225%,
Winding MVA = 204 MVA,
Rating MVA = 340 MVA</td></tr>
<tr><td>Equivalent GSU Transformer[1]</td><td colspan="4">Gen 1 Equivalent Qty: 151:
X = 5.699%, R = 0.759%,
Winding MVA = 347.3 MVA,
Rating MVA = 347.3 MVA</td></tr>
<tr><td>Equivalent Collector Line[2]</td><td colspan="4">R = 0.001841 pu
X = 0.001682 pu
B = 0.046781 pu</td></tr>
</table>

1) X/R based on Winding MVA, 2) all pu are on 100 MVA Base
*Updated from the GEN-2016-174 Modification Interconnection Request Study

Table ES-3: GEN-2016-176 Modification Request Details

Facility	Modification			
Point of Interconnection	Stranger Creek 345 kV (532772)			
Configuration/Capacity	8 x GE 2.32 MW + 100 x GE 2.82 MW = 300.56 MW			
Generation Interconnection Line	<u>Stranger Creek to GEN-2016-149:</u> Length = 38 miles R = 0.001209 pu X = 0.017664 pu B = 0.348080 pu Line Rating = 1084 MVA	<u>GEN-2016-149 to GEN-2016-174:</u> Length = 38 miles R = 0.001209 pu X = 0.017664 pu B = 0.348080 pu Line Rating = 1084 MVA	<u>GEN-2016-174 to GEN-2016-176:</u> Length = 25 miles R = 0.000795 pu X = 0.011619 pu B = 0.228890 pu Line Rating = 1276 MVA	<u>GEN-2016-176 to GEN-2016-150:</u> Length = 37 miles R = 0.001221 pu X = 0.017390 pu B = 0.339882 pu Line Rating = 0 MVA
Main Substation Transformer[1]	<u>354/34.5/34.5 kV Transformer:</u> X12 = 8.421% R12 = 0.149%, X23 = 15.028% R23 = 0.358%, X13 = 8.536% R13 = 0.155%, Winding MVA = 102 MVA, Winding 1 Rating MVA = 340 MVA, Winding 2 & 3 Rating MVA = 170 MVA			
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 8: X = 5.699%, R = 0.759%, Winding MVA = 19.2 MVA, Rating MVA = 21.5 MVA	Gen 2 Equivalent Qty: 47: X = 5.699%, R = 0.759%, Winding MVA = 131.6 MVA, Rating MVA = 152.4 MVA	Gen 3 Equivalent Qty: 53: X = 5.699%, R = 0.759%, Winding MVA = 148.4 MVA, Rating MVA = 171.8 MVA	
Equivalent Collector Line[2]	R = 0.012984 pu X = 0.022797 pu B = 0.120471 pu		R = 0.016843 pu X = 0.031334 pu B = 0.128112 pu	

1) X/R based on Winding MVA, 2) all pu are on 100 MVA Base

SPP determined that power flow should not be performed based on the POI MW injection decrease of 0.79% compared to the DISIS-2017-001 power flow models. However, SPP determined that while the modification used the same turbine manufacturer, GE, the generator model change from GEWTG2 to REGCAU1 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-2017-001 Group 13 study models:

1. 2019 Winter Peak (2019WP),
2. 2021 Light Load (2021LL)
3. 2021 Summer Peak (2021SP),
4. 2028 Summer Peak (2028SP)

Aneden updated the GIRs that shared the same POI, Stranger Creek 345 kV, as applicable based on SPP's confirmation of the latest project configurations. Modeling updates for GEN-2016-174 were included in the base models. All analyses were performed using the PTI PSS/E version 33 software and the results are summarized below.

The results of the charging current compensation analysis performed using the 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak models showed that the GEN-2016-176 project needed 50.05 MVAr of reactor shunts on the 34.5 kV bus of the project substation with the modifications in place, an increase from the 39.23 MVAr found for the existing GEN-2016-176 configuration calculated using the DISIS-2017-001 models. 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 results from the short circuit analysis with the updated topology showed that the maximum GEN-2016-176 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2016-176 POI was not greater than 0.29 kA[1] for the 2021SP and 2028SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-176 generators online were below 51 kA for the 2021SP and 2028SP models.

The dynamic stability analysis was performed using PTI PSS/E version 33.10 software and the four modified study models, 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak. Up to 52 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 no damping or voltage recovery violations attributed to the GEN-2016-176 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.

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.

[1] For buses not on the generation interconnection line

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-2016-176. 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 33 software. The results of each analysis are presented in the following sections.

1.1 Power Flow

To determine whether power flow analysis is required, SPP evaluates the difference in the real power output at the POI between the DISIS-2017-001 power flow configuration and the requested modification. Power flow analysis is included if the difference has a significant impact on the results of the DISIS study.

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 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-2016-176 Interconnection Customer has requested a modification to its Interconnection Request (IR) with a point of interconnection (POI) at the Stranger Creek 345 kV Substation. At the time of the posting of this report, GEN-2016-176 is an active Interconnection Request with a queue status of "IA FULLY EXECUTED/ON SCHEDULE." GEN-2016-176 is a wind farm and has a maximum summer and winter queue capacity of 302 MW with Energy Resource Interconnection Service (ERIS).

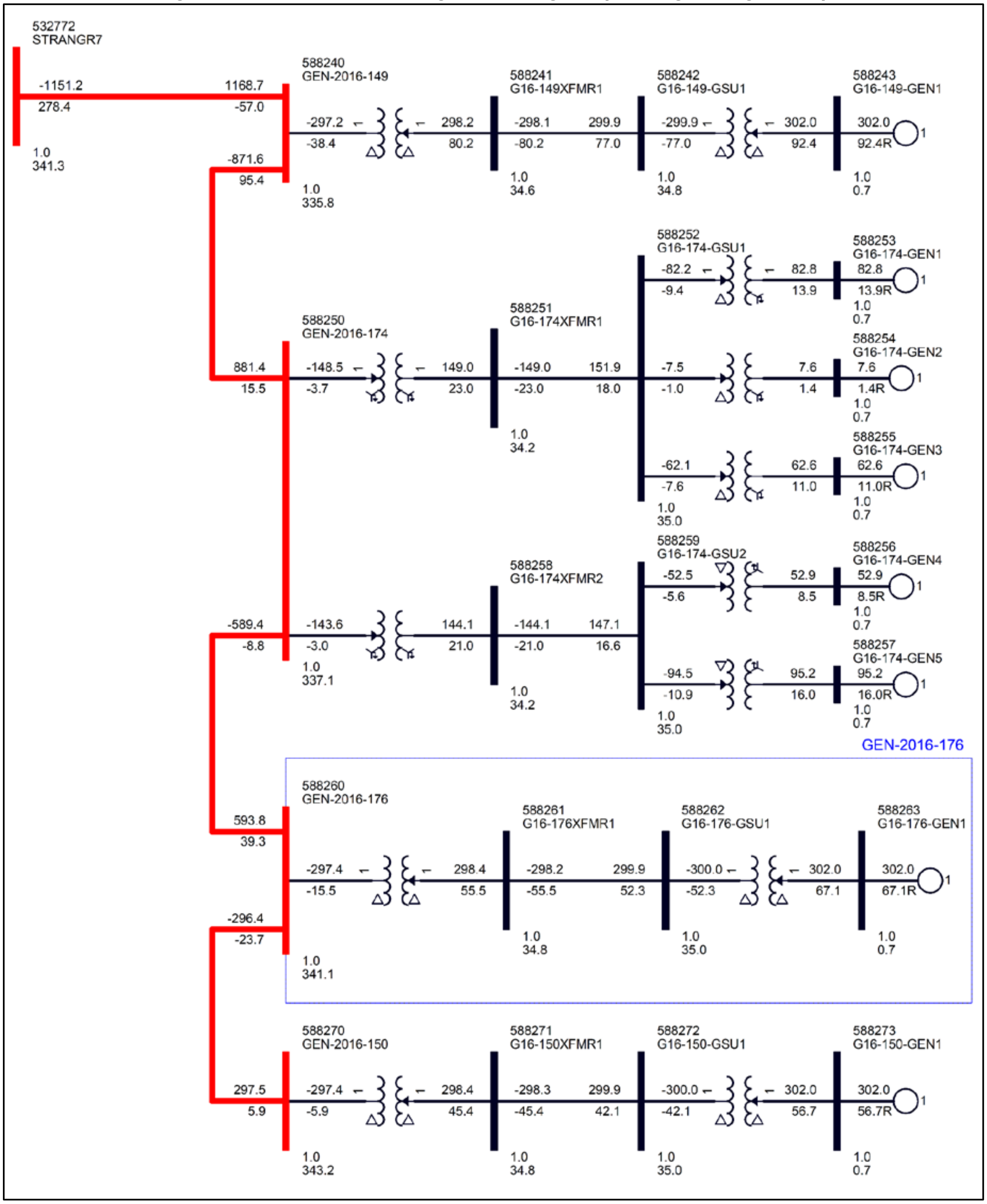
The GEN-2016-176 project was originally studied as part of Group 13 in the DISIS-2016-002 study. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2016-176 configuration. Aneden updated the GIRs that shared the same POI, Stranger Creek 345 kV, as applicable based on SPP's confirmation of the latest project configurations. Modeling updates for GEN-2016-174 were included in the base models.

The GEN-2016-176 project is proposed to interconnect in the Westar Energy (WERE) control area with a capacity of 302 MW as shown in Table 2-1 below.

Table 2-1: GEN-2016-176 Existing Configuration

Request	Point of Interconnection	Existing Generator Configuration	GIA Capacity (MW)
GEN-2016-176	Stranger Creek 345 kV (532772)	151 x GE 2.0 MW	302

Figure 2-1: GEN-2016-176 Single Line Diagram (Existing Configuration)



This Study has been requested by the Interconnection Customer to evaluate the modification of GEN-2016-176 to change the turbine configuration to 8 x GE 2.32 MW + 100 x GE 2.82 MW for a total generating capacity of 300.56 MW. In addition, the modification request included changes to the collection system, generator step-up transformers, generation interconnection line, and main substation transformer. Figure 2-2 shows the power flow model single line diagram for the GEN-

2016-176 modification. The existing and modified configurations for GEN-2016-176 are shown in Table 2-2 and Table 2-3 respectively.

Figure 2-2: GEN-2016-176 Single Line Diagram (Modification Configuration)

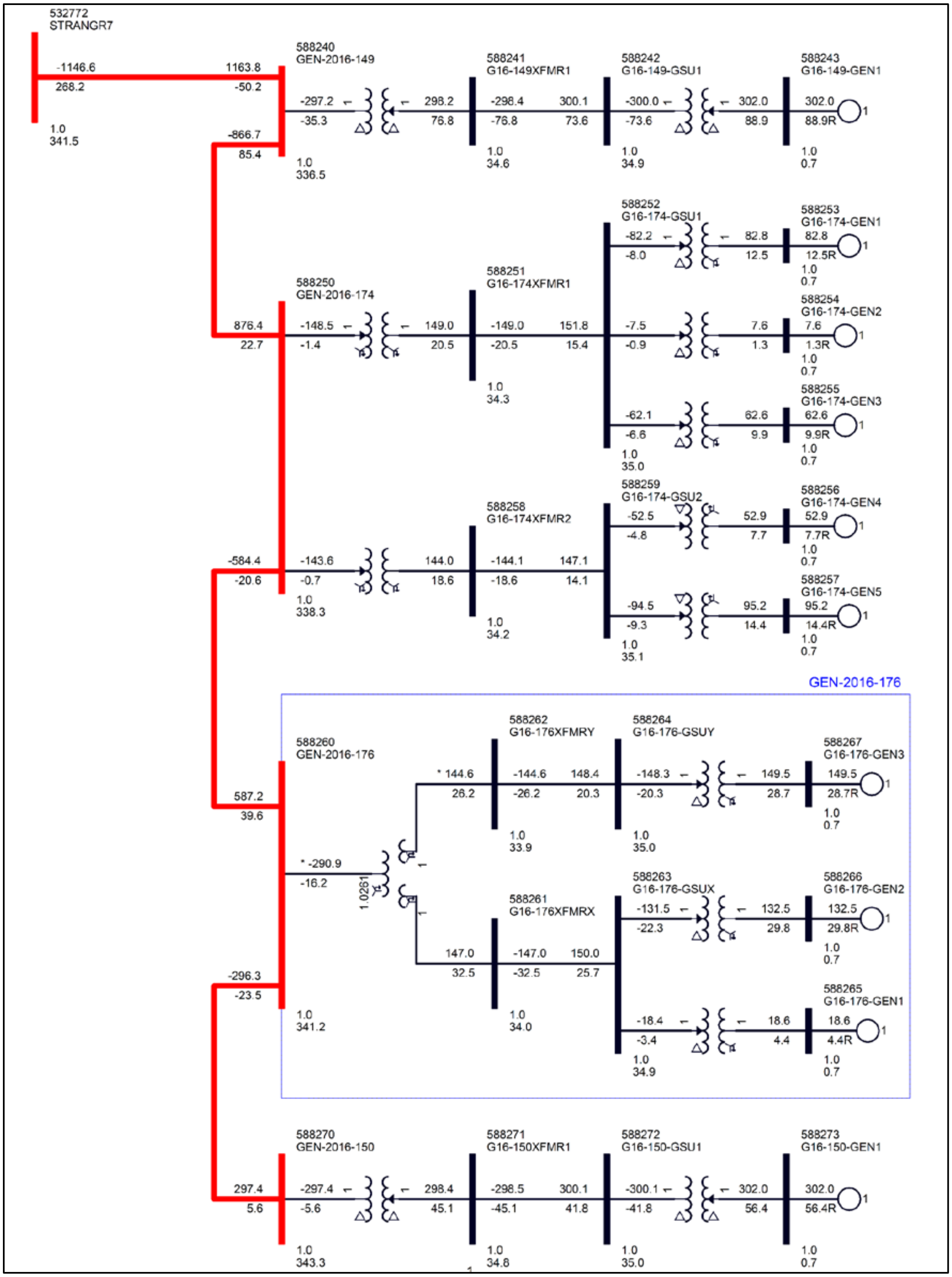


Table 2-2: GEN-2016-176 Existing Configuration Details

Facility	Existing			
Point of Interconnection	Stranger Creek 345 kV (532772)			
Configuration/Capacity	151 x GE 2.0 MW = 302 MW			
Generation Interconnection Line	Stranger Creek to GEN-2016-149: Length = 38 miles* R = 0.001209 pu* X = 0.017664 pu* B = 0.348080 pu* Line Rating = 1084 MVA*	GEN-2016-149 to GEN-2016-174: Length = 38 miles* R = 0.001209 pu* X = 0.017664 pu* B = 0.348080 pu* Line Rating = 1084 MVA*	GEN-2016-174 to GEN-2016-176: Length = 37 miles R = 0.001221 pu X = 0.017390 pu B = 0.339882 pu Line Rating = 0 MVA	GEN-2016-176 to GEN-2016-150: Length = 37 miles R = 0.001221 pu X = 0.017390 pu B = 0.339882 pu Line Rating = 0 MVA
Main Substation Transformer[1]	345/34.5 kV Transformer: X = 8.997% R = 0.225%, Winding MVA = 204 MVA, Rating MVA = 340 MVA			
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 151: X = 5.699%, R = 0.759%, Winding MVA = 347.3 MVA, Rating MVA = 347.3 MVA			
Equivalent Collector Line[2]	R = 0.001841 pu X = 0.001682 pu B = 0.046781 pu			

1) X/R based on Winding MVA, 2) all pu are on 100 MVA Base
*Updated from the GEN-2016-174 Modification Interconnection Request Study

Table 2-3: GEN-2016-176 Modification Request Details

Facility	Modification			
Point of Interconnection	Stranger Creek 345 kV (532772)			
Configuration/Capacity	8 x GE 2.32 MW + 100 x GE 2.82 MW = 300.56 MW			
Generation Interconnection Line	Stranger Creek to GEN-2016-149: Length = 38 miles R = 0.001209 pu X = 0.017664 pu B = 0.348080 pu Line Rating = 1084 MVA	GEN-2016-149 to GEN-2016-174: Length = 38 miles R = 0.001209 pu X = 0.017664 pu B = 0.348080 pu Line Rating = 1084 MVA	GEN-2016-174 to GEN-2016-176: Length = 25 miles R = 0.000795 pu X = 0.011619 pu B = 0.228890 pu Line Rating = 1276 MVA	GEN-2016-176 to GEN-2016-150: Length = 37 miles R = 0.001221 pu X = 0.017390 pu B = 0.339882 pu Line Rating = 0 MVA
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Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 8: X = 5.699%, R = 0.759%, Winding MVA = 19.2 MVA, Rating MVA = 21.5 MVA	Gen 2 Equivalent Qty: 47: X = 5.699%, R = 0.759%, Winding MVA = 131.6 MVA, Rating MVA = 152.4 MVA	Gen 3 Equivalent Qty: 53: X = 5.699%, R = 0.759%, Winding MVA = 148.4 MVA, Rating MVA = 171.8 MVA	
Equivalent Collector Line[2]	R = 0.012984 pu X = 0.022797 pu B = 0.120471 pu		R = 0.016843 pu X = 0.031334 pu B = 0.128112 pu	

1) X/R based on Winding MVA, 2) all pu are on 100 MVA Base

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-2017-001 Group 13 study models.

Aneden updated the GIRs that shared the same POI, Stranger Creek 345 kV, as applicable based on SPP's confirmation of the latest project configurations. Modeling updates for GEN-2016-174 were included in the base models.

The methodology and results of the comparisons are described below. The analysis was completed using PSS/E version 33 software.

3.1 POI Injection Comparison

The real power injection at the POI was determined using PSS/E to compare the DISIS-2017-001 power flow configuration and the requested modifications for GEN-2016-176. 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 (decrease of 0.79%) in the real power output at the POI between the studied DISIS-2017-001 power flow configuration and requested modification shown in Table 3-1. The MW shown includes injections from both the GEN-2016-176 project and nearby projects GEN-2016-149, GEN-2016-150, and GEN-2016-174 which share the gen-tie line with GEN-2016-176.

Table 3-1: GEN-2016-176 POI Injection Comparison

Interconnection Request	Existing POI Injection (MW)	MRIS POI Injection (MW)	POI Injection Difference %
GEN-2016-176	1155.7*	1146.6*	-0.79%

*The total MW amount includes the GEN-2016-149, GEN-2016-150, & GEN-2016-174 projects which share the gen-tie line

3.2 Turbine Parameters Comparison

SPP determined that while the modification used the same turbine manufacturer, GE, the generator model change from GEWTG2 to REGCAU1 required short circuit and dynamic stability analyses as 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-2016-176 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

There are four projects connected in series to the POI: GEN-2016-149, GEN-2016-174, GEN-2016-176, and GEN-2016-150. A reactor size was determined for each project sequentially, starting with GEN-2016-149 while the radially connected systems were disconnected. For the project being studied, generators were switched out of service while other collection 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).

4.2 Results

The results from the analysis showed that the GEN-2016-176 project needed approximately 50.05 MVAr of compensation at its project substation, to reduce the POI MVAr to zero. This is an increase from the 39.23 MVAr found for the existing GEN-2016-176 configuration calculated using the DISIS-2017-001 models. Figure 4-1 illustrates the shunt reactor size needed to reduce the POI MVAr to approximately zero with the existing configuration. Figure 4-2 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-2016-176 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)			
			19WP	21LL	21SP	28SP
GEN-2016-176	532772	Stranger Creek 345 kV	50.05	50.05	50.05	50.05

Figure 4-1: GEN-2016-176 Single Line Diagram (Existing Shunt Reactor)

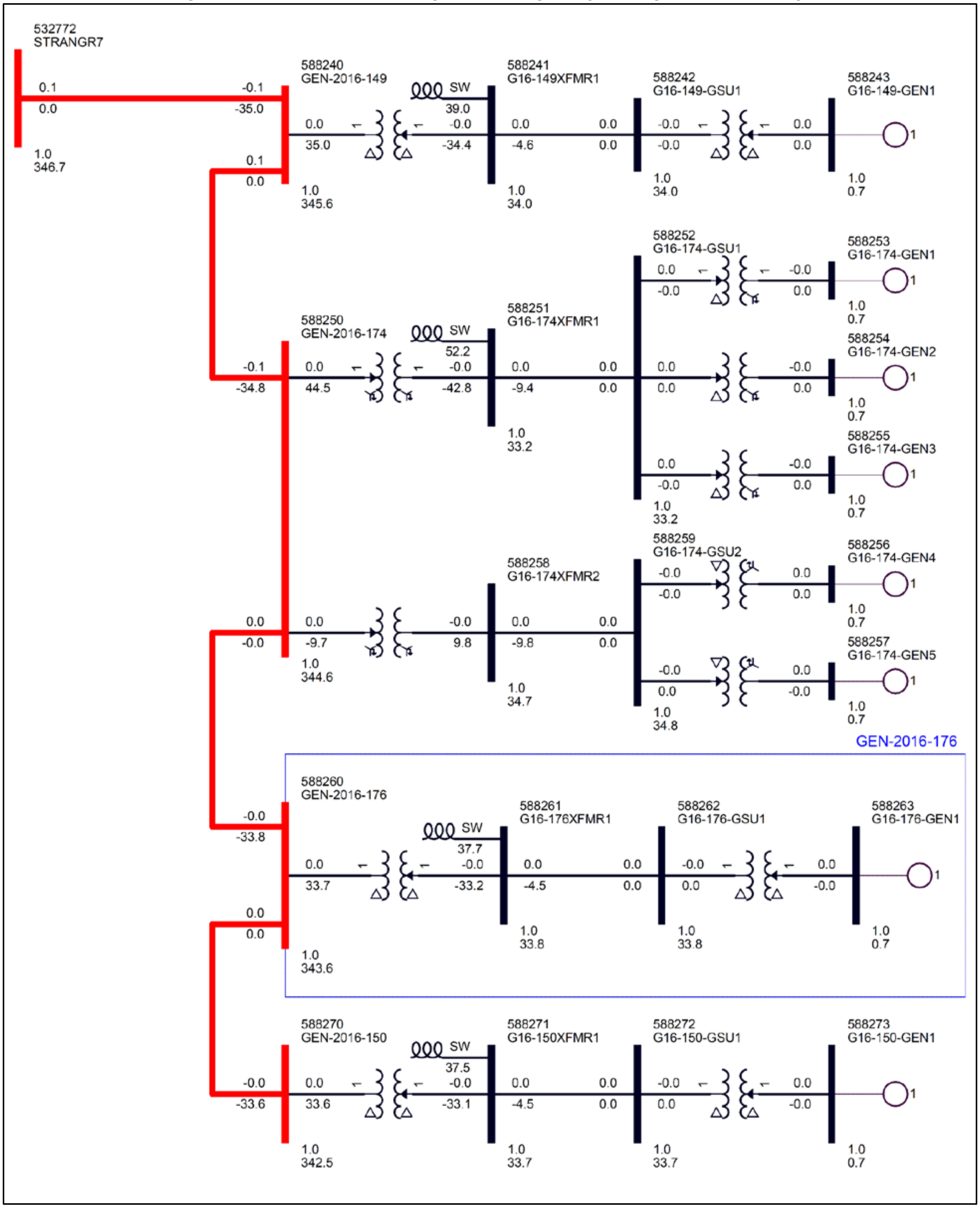
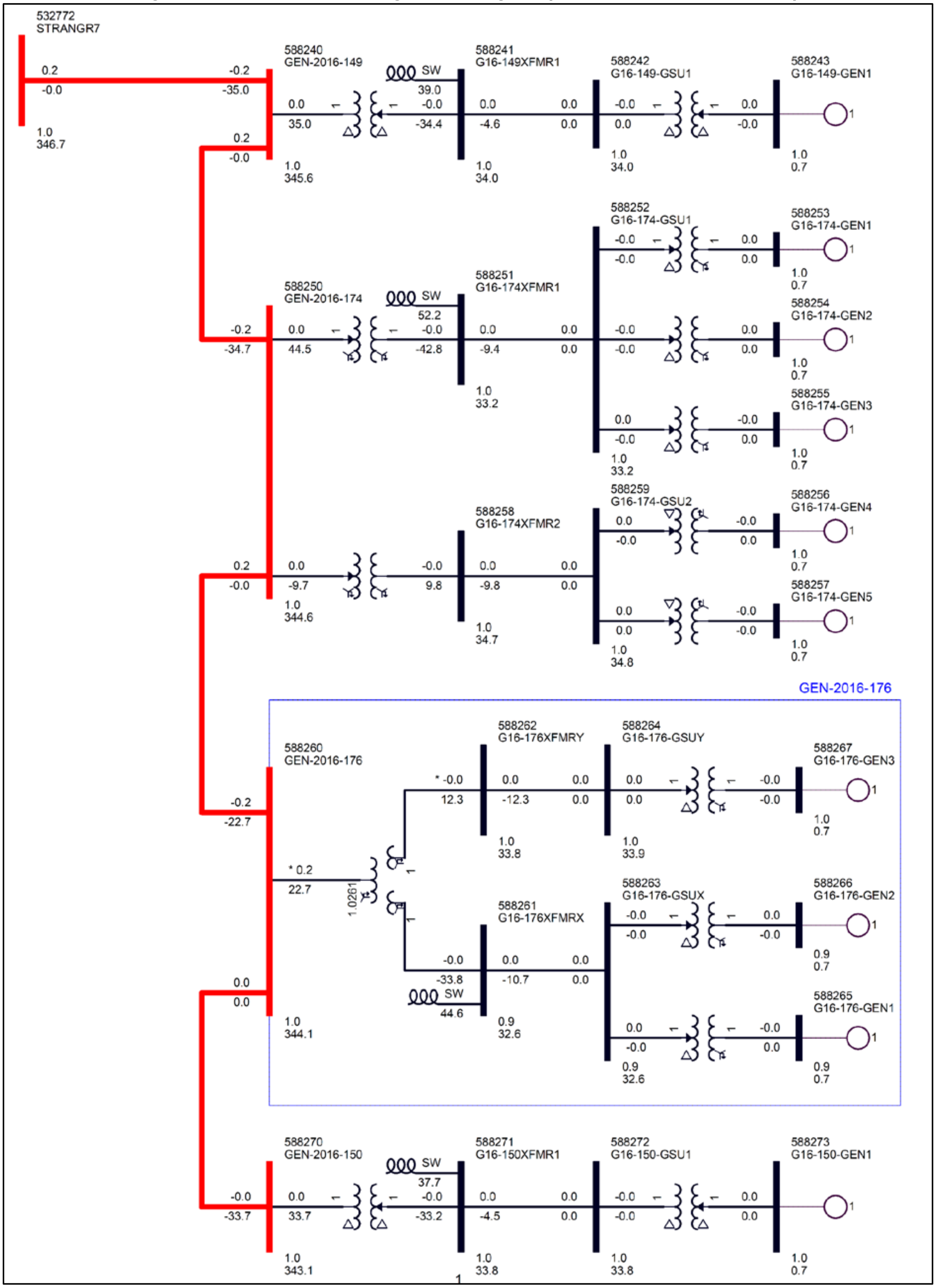


Figure 4-2: GEN-2016-176 Single Line Diagram (Modification Shunt Reactor)



5.0 Short Circuit Analysis

A short circuit study was performed using the 2021SP and 2028SP models for GEN-2016-176. 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-2016-176 online. GEN-2016-149, GEN-2016-174, and GEN-2016-150 were left online throughout the analysis.

5.2 Results

The results of the short circuit analysis for the 2021SP and 2028SP models are summarized in Table 5-1 through Table 5-3 respectively. The GEN-2016-176 POI bus fault current magnitudes are provided in Table 5-1 showing a maximum fault current of 25.62 kA with the GEN-2016-176 project online.

The maximum fault current calculated within 5 buses of the GEN-2016-176 POI was less than 51 kA for the 2021SP and 2028SP models respectively. The maximum GEN-2016-176 contribution to three-phase fault current was about 1.2% and 0.29 kA[2].

Table 5-1: POI Short Circuit Results

Case	GEN-OFF Current (kA)	GEN-ON Current (kA)	Max kA Change	Max %Change
2021SP	25.33	25.62	0.29	1.2%
2028SP	25.18	25.48	0.29	1.2%

Table 5-2: 2021SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	8.7	-0.01	-0.3%
115	33.5	-0.01	-0.1%
161	50.9	-0.01	0.0%
230	25.1	-0.01	0.0%
345	28.9	0.29	1.2%
Max	**50.9**	**0.29**	**1.2%**

Table 5-3: 2028SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	8.6	-0.01	-0.3%
115	33.4	-0.01	-0.1%
161	50.8	-0.01	0.0%
230	25.1	-0.01	-0.1%
345	28.9	0.29	1.2%
Max	**50.8**	**0.29**	**1.2%**

[2] 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 turbine configuration change and other modifications to the GEN-2016-176 project. 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-2016-176 configuration of 8 x GE 2.32 MW (REGCAU1) + 100 x 2.82 MW (REGCAU1). This stability analysis was performed using PTI's PSS/E version 33.10 software.

The stability models were developed using the DISIS-2017-001 Group 13 models. The modifications requested for the GEN-2016-176 projects were used to create modified stability models for this impact study. Aneden updated the GIRs that shared the same POI, Stranger Creek 345 kV, as applicable based on SPP's confirmation of the latest project configurations. Modeling updates for GEN-2016-174 were included in the base models.

The following system adjustment was made to address existing base case issues that are not attributed to the modification request:

1. The governor model GGOV1 CON(J+23) parameter was changed from 1.0 to 0.002 for the OEC generators at buses 511939, 511940, 511942, and 511943.

The modified dynamics model data for the GEN-2016-176 project is provided in Appendix A. The modified power flow models and associated dynamics database were initialized (no-fault test) to confirm that there were no errors in the initial conditions of the system and the dynamic data.

During the fault simulations, the active power (PELEC), reactive power (QELEC), and terminal voltage (ETERM) were monitored for GEN-2016-176 and other equally and prior queued projects in Group 13. In addition, voltages of five (5) buses away from the POI of GEN-2016-176 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within this study area including 536 (WERE), 540 (GMO), 541 (KCPL), 542 (KACY), 544 (EMDE), 545 (INDN), 635 (MEC), 640 (NPPD), 645 (OPPD), 650 (LES), 652 (WAPA), 330 (AECI), 356 (AMMO) 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-2016-176 and developed additional fault events as required. The new set of faults were simulated using the modified study models. The fault events included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults. The simulated faults are listed and described in Table 6-1 below. These contingencies were applied to the modified 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and the 2028 Summer Peak models.

Table 6-1: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT01-3PH	P1	3 phase fault on the STRANGR7 (532772) to IATAN 7 (542982) 345 kV line circuit 1, near STRANGR7. a. Apply fault at the STRANGR7 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.
FLT02-3PH	P1	3 phase fault on the STRANGR7 (532772) to 87TH 7 (532775) 345 kV line circuit 1, near STRANGR7. a. Apply fault at the STRANGR7 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.
FLT13-3PH	P1	3 phase fault on the NASHUA 7 (542980) to IATAN 7 (542982) 345 kV line circuit 1, near NASHUA 7. a. Apply fault at the NASHUA 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.
FLT14-3PH	P1	3 phase fault on the ST JOE 3 (541199) to EASTOWN7 (541400) 345 kV line circuit 1, near ST JOE 3. a. Apply fault at the ST JOE 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT16-3PH	P1	3 phase fault on the ST JOE 3 (541199) to NASHUA 7 (542980) 345 kV line circuit 1, near ST JOE 3. a. Apply fault at the ST JOE 3 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT21-3PH	P1	3 phase fault on the NASHUA11 345 kV (542980) / 161 kV (543028) /13.8 kV (543640) XFMR CKT 11, near NASHUA 7 345 kV. a. Apply fault at the NASHUA 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT01-PO1	P6	**PRIOR OUTAGE of STRANGR7 (532772) to HOYT 7 (532765) 345 kV line circuit 1;** 3 phase fault on the STRANGR7 (532772) to IATAN 7 (542982) 345 kV line circuit 1, near STRANGR7. a. Apply fault at the STRANGR7 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.
FLT02-PO1	P6	**PRIOR OUTAGE of STRANGR7 (532772) to HOYT 7 (532765) 345 kV line circuit 1;** 3 phase fault on the STRANGR7 (532772) to 87TH 7 (532775) 345 kV line circuit 1, near STRANGR7. a. Apply fault at the STRANGR7 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.
FLT9001-3PH	P1	3 phase fault on the STRANGR7 (532772) to HOYT 7 (532765) 345 kV line circuit 1, near STRANGR7. a. Apply fault at the STRANGR7 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 STRA TX-3 345 kV (532772) / 115 kV (533268) /14.4 kV (532816) XFMR CKT 1, near STRA TX-3 345 kV. a. Apply fault at the STRANGR7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT9003-3PH	P1	3 phase fault on the IATAN 7 (542982) to NASHUA 7 (542980) 345 kV line circuit 1, near IATAN 7. a. Apply fault at the IATAN 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.
FLT9004-3PH	P1	3 phase fault on the IATAN 7 (542982) to G17-030-TAP (588736) 345 kV line circuit 1, near IATAN 7. a. Apply fault at the IATAN 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 IATAN11 345 kV (542982) / 161 kV (541350) /13.8 kV (541150) XFMR CKT 11, near IATAN 7 345 kV. a. Apply fault at the IATAN 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9006-3PH	P1	3 phase fault on the IATAN 1 GSU 345 kV (542982) / 24 kV (542957) XFMR CKT 1, near IATAN 7 345 kV. a. Apply fault at the IATAN 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer. **Trip the generator IAT G1 1 (542957).**
FLT9007-3PH	P1	3 phase fault on the NASHUA 7 (542980) to HAWTH 7 (542972) 345 kV line circuit 1, near NASHUA 7. a. Apply fault at the NASHUA 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.
FLT9008-3PH	P1	3 phase fault on the NASHUA 7 (542980) to ST JOE 3 (541199) 345 kV line circuit 1, near NASHUA 7. a. Apply fault at the NASHUA 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.
FLT9009-3PH	P1	3 phase fault on the G17-030-TAP (588736) to EASTOWN7 (541400) 345 kV line circuit 1, near G17-030-TAP. a. Apply fault at the G17-030-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.
FLT9011-3PH	P1	3 phase fault on the 87TH TX-1 345 kV (532775) / 115 kV (533283) /13.8 kV (532818) XFMR CKT 1, near 87TH 7 345 kV. a. Apply fault at the 87TH 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9012-3PH	P1	3 phase fault on the 87TH 7 (532775) to CRAIG 7 (542977) 345 kV line circuit 1, near 87TH 7. a. Apply fault at the 87TH 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9013-3PH	P1	3 phase fault on the CRAIG11 345 kV (542977) / 161 kV (542978) /13.8 kV (543641) XFMR CKT 11, near CRAIG 7 345 kV. a. Apply fault at the CRAIG 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
FLT9014-3PH	P1	3 phase fault on the CRAIG 7 (542977) to W.GRDNR7 (542965) 345 kV line circuit 1, near CRAIG 7. a. Apply fault at the CRAIG 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.
FLT9015-3PH	P1	3 phase fault on the HOYT TX-1 345 kV (532765) / 115 kV (533163) /14.4 kV (532804) XFMR CKT 1, near HOYT 7 345 kV. a. Apply fault at the HOYT 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9016-3PH	P1	3 phase fault on the HOYT 7 (532765) to JEC N 7 (532766) 345 kV line circuit 1, near HOYT 7. a. Apply fault at the HOYT 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.
FLT9017-3PH	P1	3 phase fault on the JEC N 7 (532766) to GEARY 7 (532767) 345 kV line circuit 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.
FLT9018-3PH	P1	3 phase fault on the JEC N 7 (532766) to MORRIS 7 (532770) 345 kV line circuit 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.
FLT9019-3PH	P1	3 phase fault on the JEC TX-13 345 kV (532766) /230 kV (532852) /14.4 kV (532805) XFMR CKT 1, near JEC N 7 345 kV. a. Apply fault at the JEC N 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9020-3PH	P1	3 phase fault on the JEC3 GSU 345 kV (532766) / 26 kV (532653) XFMR CKT 1, near JEC N 7 345 kV. a. Apply fault at the JEC N 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer. **Trip the generator JEC U3 (532653).**
FLT9002-PO1	P6	**PRIOR OUTAGE of STRANGR7 (532772) to HOYT 7 (532765) 345 kV line circuit 1;** 3 phase fault on the STRA TX-3 345 kV (532772) / 115 kV (533268) /14.4 kV (532816) XFMR CKT 1, near STRA TX-3 345 kV. a. Apply fault at the STRANGR7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT01-PO2	P6	**PRIOR OUTAGE of STRANGR7 (532772) to IATAN 7 (542982) 345 kV line circuit 2;** 3 phase fault on the STRANGR7 (532772) to IATAN 7 (542982) 345 kV line circuit 1, near STRANGR7. a. Apply fault at the STRANGR7 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.
FLT02-PO2	P6	**PRIOR OUTAGE of STRANGR7 (532772) to IATAN 7 (542982) 345 kV line circuit 2;** 3 phase fault on the STRANGR7 (532772) to 87TH 7 (532775) 345 kV line circuit 1, near STRANGR7. a. Apply fault at the STRANGR7 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
FLT9001-PO2	P6	**PRIOR OUTAGE of STRANGR7 (532772) to IATAN 7 (542982) 345 kV line circuit 2;** 3 phase fault on the STRANGR7 (532772) to HOYT 7 (532765) 345 kV line circuit 1, near STRANGR7. a. Apply fault at the STRANGR7 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-PO2	P6	**PRIOR OUTAGE of STRANGR7 (532772) to IATAN 7 (542982) 345 kV line circuit 2;** 3 phase fault on the STRA TX-3 345 kV (532772) / 115 kV (533268) /14.4 kV (532816) XFMR CKT 1, near STRA TX-3 345 kV. a. Apply fault at the STRANGR7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT01-PO3	P6	**PRIOR OUTAGE of STRA TX-3 345 kV (532772) / 115 kV (533268) /14.4 kV (532816) XFMR CKT 2;** 3 phase fault on the STRANGR7 (532772) to IATAN 7 (542982) 345 kV line circuit 1, near STRANGR7. a. Apply fault at the STRANGR7 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.
FLT02-PO3	P6	**PRIOR OUTAGE of STRA TX-3 345 kV (532772) / 115 kV (533268) /14.4 kV (532816) XFMR CKT 2;** 3 phase fault on the STRANGR7 (532772) to 87TH 7 (532775) 345 kV line circuit 1, near STRANGR7. a. Apply fault at the STRANGR7 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.
FLT9001-PO3	P6	**PRIOR OUTAGE of STRA TX-3 345 kV (532772) / 115 kV (533268) /14.4 kV (532816) XFMR CKT 2;** 3 phase fault on the STRANGR7 (532772) to HOYT 7 (532765) 345 kV line circuit 1, near STRANGR7. a. Apply fault at the STRANGR7 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-PO3	P6	**PRIOR OUTAGE of STRA TX-3 345 kV (532772) / 115 kV (533268) /14.4 kV (532816) XFMR CKT 2;** 3 phase fault on the STRA TX-3 345 kV (532772) / 115 kV (533268) /14.4 kV (532816) XFMR CKT 1, near STRA TX-3 345 kV. a. Apply fault at the STRANGR7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT01-PO4	P6	**PRIOR OUTAGE of STRANGR7 (532772) to 87TH 7 (532775) 345 kV line circuit 1;** 3 phase fault on the STRANGR7 (532772) to IATAN 7 (542982) 345 kV line circuit 1, near STRANGR7. a. Apply fault at the STRANGR7 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.
FLT9001-PO4	P6	**PRIOR OUTAGE of STRANGR7 (532772) to 87TH 7 (532775) 345 kV line circuit 1;** 3 phase fault on the STRANGR7 (532772) to HOYT 7 (532765) 345 kV line circuit 1, near STRANGR7. a. Apply fault at the STRANGR7 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-PO4	P6	**PRIOR OUTAGE of STRANGR7 (532772) to 87TH 7 (532775) 345 kV line circuit 1;** 3 phase fault on the STRA TX-3 345 kV (532772) / 115 kV (533268) /14.4 kV (532816) XFMR CKT 1, near STRA TX-3 345 kV. a. Apply fault at the STRANGR7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT1001-SB	P4	**Stuck Breaker on at HOYT (532765) at 345kV bus** a. Apply single-phase fault at HOYT (532765) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the Bus HOYT (532765).

Table 6-1 continued

Fault ID	Planning Event	Fault Descriptions
FLT1002-SB	P4	**Stuck Breaker on at 87TH 7 (532775) at 345kV bus** a. Apply single-phase fault at 87TH 7 (532775) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the Bus 87TH 7 (532775).
FLT1003-SB	P4	**Stuck Breaker on at IATAN (542982) at 345kV bus** a. Apply single-phase fault at IATAN (542982) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the IATAN (542982) to NASHUA (542980) circuit 1 line. d. Trip the IATAN (542982) to G17-030-TAP (588736) 345kV line circuit 1.
FLT1004-SB	P4	**Stuck Breaker on at IATAN (542982) at 345kV bus** a. Apply single-phase fault at IATAN (542982) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the IATAN (542982) to STRANGR7 (532772) circuit 1 line. d. Trip the IATAN 1 GSU 345 kV (542982) / 24.5 kV (542957) XFMR CKT 1. Trip IATAN Unit 1 e. Trip the IATAN 2 GSU 345 kV (542982) / 24.5 kV (542962) XFMR CKT 1. Trip IATAN Unit 2
FLT1005-SB	P4	**Stuck Breaker on the STRANGR7 (532772) 345kV** a. Apply single-phase fault at the STRANGR7 345kV bus. b. After 16 cycles, trip the following elements c. Trip the STRANGR7 (532772) to HOYT 7 (532765) 345kV line circuit 1. d. Trip the STRANGR7 (532772) to 87TH 7 (532775) 345kV line circuit 1.
FLT1006-SB	P4	**Stuck Breaker on the STRANGR7 (532772) 345kV** a. Apply single-phase fault at the STRANGR7 345kV bus. b. After 16 cycles, trip the following elements c. Trip the STRANGR7 (532772) to HOYT 7 (532765) 345kV line circuit 1. d. Trip the STRA TX-1 345/115/14.4kV (532772/533268/532811) transformer circuit 1.
FLT1007-SB	P4	**Stuck Breaker on the STRANGR7 (532772) 345kV** a. Apply single-phase fault at the STRANGR7 345kV bus. b. After 16 cycles, trip the following elements c. Trip the STRANGR7 (532772) to IATAN 7 (542982) 345kV line circuit 2. d. Trip the STRA TX-3 345/115/14.4kV (532772/533268/532816) transformer circuit 1.
FLT1008-SB	P4	**Stuck Breaker on the STRANGR7 (532772) 345kV** a. Apply single-phase fault at the STRANGR7 345kV bus. b. After 16 cycles, trip the following elements c. Trip the STRANGR7 (532772) to IATAN 7 (542982) 345kV line circuit 2. d. Trip the STRA TX-1 345/115/14.4kV (532772/533268/532811) transformer circuit 1.
FLT1009-SB	P4	**Stuck Breaker on the STRANGR7 (532772) 345kV** a. Apply single-phase fault at the STRANGR7 345kV bus. b. After 16 cycles, trip the following elements c. Trip the STRANGR7 (532772) to IATAN 7 (542982) 345kV line circuit 1. d. Trip the STRA TX-3 345/115/14.4kV (532772/533268/532816) transformer circuit 1.
FLT1010-SB	P4	**Stuck Breaker on the STRANGR7 (532772) 345kV** a. Apply single-phase fault at the STRANGR7 345kV bus. b. After 16 cycles, trip the following elements c. Trip the STRANGR7 (532772) to IATAN 7 (542982) 345kV line circuit 1. d. Trip the STRANGR7 (532772) to 87TH 7 (532775) 345kV line circuit 1.
FLT1011-SB	P4	**Stuck Breaker on the STRANGR3 (533268) 115kV** a. Apply single-phase fault at the STRANGR7 345kV bus. b. After 16 cycles, trip the following elements c. Trip the STRANGR3 (533268) to ARNOLD 3 (533211) 115kV line circuit 1. d. Trip the STRANGR3 (533268) to JARBALO3 (533244) 115kV line circuit 1.
FLT1012-SB	P4	**Stuck Breaker on the STRANGR3 (533268) 115kV** a. Apply single-phase fault at the STRANGR7 345kV bus. b. After 16 cycles, trip the following elements c. Trip the STRA TX-3 345/115/14.4kV (532772/533268/532816) transformer circuit 1. d. Trip the STRANGR3 (533268) to JARBALO3 (533244) 115kV line circuit 2.
FLT1013-SB	P4	**Stuck Breaker on the STRANGR3 (533268) 115kV** a. Apply single-phase fault at the STRANGR7 345kV bus. b. After 16 cycles, trip the following elements c. Trip the STRA TX-1 345/115/14.4kV (532772/533268/532811) transformer circuit 1. d. Trip the STRANGR3 (533268) to NW LEAV3 (533259) 115kV line circuit 1.

6.3 Results

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

Table 6-2: GEN-2016-176 Dynamic Stability Results

Fault ID	19WP			21LL			21SP			26SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT01-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT13-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT14-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT16-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT21-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 6-2 continued

Fault ID	19WP			21LL			21SP			26SP		
	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable	Volt Violation	Volt Recovery	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1009-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1010-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1011-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1012-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1013-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT01-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT01-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT01-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT02-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT01-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO4	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

There were no damping or voltage recovery violations attributed to the GEN-2016-176 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 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 resulted in similar dynamic stability and short circuit analyses and that the prior study power flow results are not negatively impacted.

This determination implies that any network upgrades already required by GEN-2016-176 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.

8.0 Conclusions

The Interconnection Customer for GEN-2016-176 requested a Modification Request Impact Study to assess the impact of the turbine and facility change to a configuration of 8 x GE 2.32 MW + 100 x GE 2.82 MW for a total generating capacity of 300.56 MW.

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

SPP determined that power flow should not be performed based on the POI MW injection decrease of 0.79% compared to the recently studied DISIS-2017-001 power flow models. However, SPP determined that while the modification used the same turbine manufacturer, GE, the generator model change from GEWTG2 to REGCAU1 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 updated the GIRs that shared the same POI, Stranger Creek 345 kV, as applicable based on SPP's confirmation of the latest project configurations. Modeling updates for GEN-2016-174 were included in the base models. All analyses were performed using the PTI PSS/E version 33 software and the results are summarized below.

The results of the charging current compensation analysis performed using the 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak models showed that the GEN-2016-176 project needed 50.05 MVAr of reactor shunts on the 34.5 kV bus of the project substation with the modifications in place, an increase from the 39.23 MVAr found for the existing GEN-2016-176 configuration calculated using the DISIS-2017-001 models. 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 results from the short circuit analysis with the updated topology showed that the maximum GEN-2016-176 contribution to three-phase fault currents in the immediate transmission systems at or near the GEN-2016-176 POI was not greater than 0.29 kA[3] for the 2021SP and 2028SP models. All three-phase fault current levels within 5 buses of the POI with the GEN-2016-176 generators online were below 51 kA for the 2021SP and 2028SP models.

The dynamic stability analysis was performed using PTI PSS/E version 33.10 software and the four modified study models, 2019 Winter Peak, 2021 Light Load, 2021 Summer Peak, and 2028 Summer Peak. Up to 52 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground stuck breaker faults.

[3] For buses not on the generation interconnection line

The results of the dynamic stability analysis showed that there were no damping or voltage recovery violations attributed to the GEN-2016-176 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.

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.