GEN-2015-021

Impact Restudy for Generator Modification

Published August 2019
By SPP Generator Interconnections Dept.

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
08/15/2019	SPP	Initial report issued.
09/05/2019	SPP	Reposted to include additional inverter modification requested by customer.

CONTENTS

SUMMARY

The GEN-2015-021 Interconnection Customer has requested a modification to its 20 MW Interconnection Request. This system impact restudy was performed to determine the effects of changing solar inverters from 5 GE LV5 4 MW inverters (for a total of 20 MW) to 184 Sungrow SG125 0.1075 MW inverters (for a total of 19.78 MW). In addition, the modification request included changes to the collection system and the generator substation transformer. The point of interconnection (POI) for GEN-2015-021 remains at the Johnson Corner 115 kV Substation.

This study was performed by Aneden Consulting to determine whether the request for modification is considered Material. A short circuit analysis, a low-wind/no-wind condition analysis, and stability analysis was performed for this modification request. The study report follows this executive summary.

The generating facility will be required to maintain a 95% lagging (providing VARs) and 95% leading (absorbing VArs) in accordance with FERC Order 827. Additionally, the project will be required to install approximately 0.14 MVArs of reactor shunts on its substation 115 kV bus or provide an alternate means of reactive power compensation. 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/no-wind conditions.

There were no other machine rotor angle damping or transient voltage recovery violations observed in the simulated fault events. Additionally, the project wind farm 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 is not considered Material.

It should be noted that this study analyzed the requested modification to change generator technology and layout. Powerflow analysis was not performed. This study analyzed many of the most probable contingencies, but it is not an all-inclusive list and cannot account for every operational situation. It is likely that the customer may be required to reduce its generation output to 0 MW, 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.

After the original modification request study was completed, the Interconnection Customer requested a change to project capacity from 184 inverters at 0.1075 MW (19.78 MW) to 184 inverters at 0.1087 MW (20.00 MW), a total project capacity increase of 0.22 MW. The three-phase faults at the POI (Johnson Corner) were simulated to verify the impact of the 0.22 MW increase on system stability.

The results showed that there was no additional stability issue observed with the POI faults simulated. As a result, the generator facility modification at the requested capacity of 20.0 MW is not considered a Material Modification.

A: CONSULTANT'S MATERIAL MODIFICATION STUDY REPORT

See next page for the Consultant's Material Modification Study report.

Submitted to
Southwest Power Pool

Report On

GEN-2015-021
Modification Request Impact Study

Revision R2

Date of Submittal
September 5, 2019

anedenconsulting.com

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Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2015-021, an active generation interconnection request with point of interconnection (POI) at Johnson Corner 115kV Substation.

The GEN-2015-021 project was proposed to interconnect in the Sunflower Electric Power Corporation (SUNC) control area with a capacity of 20 MW as shown in Table ES-1 below. This Study has been requested to evaluate the modification of GEN-2015-021 to change the solar farm configuration to a total of 184 x Sungrow SG125 0.1075MW inverters for a total capacity of 19.78 MW. In addition, the modification request included changes to the collection system and the generator substation transformer. The modification request changes are shown in Table ES-2 below.

Table ES-1: Existing GEN-2015-021 Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2015-021	20	5 x GE LV5 4MW	Johnson Corner 115kV Substation

Table ES-2: GEN-2015-021 Modification Request

Facility	Existing	Modification Request	
Point of Interconnection	Johnson Corner 115 kV Substation (531424)	Johnson Corner 115 kV Substation (531424)	
Configuration/Capacity	5 x GE LV5 4MW = 20 MW	184 x Sungrow SG125 0.1075MW = 19.78 MW	
Generation Interconnection Line	Length = 0.038 miles R = 0.000090 pu X = 0.000220 pu B = 0.000000 pu	Length = 0.038 miles R = 0.000090 pu X = 0.000220 pu B = 0.000000 pu	
Main Substation Transformer	Z = 5.7%, Winding 15 MVA, Rating A 20 MVA, Rating B 25 MVA	Z12 = 7%, Z23 = 2.5%, Z13 = 10.9%, Rating 25 MVA	
GSU Transformer	Gen Equivalent Qty: 5 Z = 6%, Rating 20 MVA	Gen 1 Equivalent Qty: 120 Z = 5.8%, Rating 15 MVA	Gen 2 Equivalent Qty: 64 Z = 5.74%, Rating 8 MVA
Equivalent Collector Line	R = 0.020780 pu X = 0.006760 pu B = 0.002120 pu	R = 0.012879 pu X = 0.003865 pu B = 0.001391 pu	

GEN-2015-021 was last studied as part of Group 3 in the DISIS-2015-001. Aneden performed reactive power analysis, short circuit analysis and dynamic stability analysis using the modification request data with the DISIS-2016-002 Group 3 study models created for this study.

All analyses were performed using the PTI PSS/E version 33.7 software and the results are summarized below.

A power factor analysis was not performed as there was no change in the point of interconnection for GEN-2015-021.

The results of the reactive power analysis, also known as the low or reduced generation analysis, performed using the three main models showed that the GEN-2015-021 project may require a 0.14 MVAr shunt reactor on the 115kV bus of the project substation. The shunt reactor is needed to reduce the reactive power transfer at the POI to approximately zero during low/no irradiance conditions while the generation interconnection project remains connected to the grid.

The results from the short circuit analysis showed that the maximum change in the fault currents in the immediate systems at or near GEN-2015-021 was approximately 0.03 kA for both the 2018SP and 2026SP respectively. All three-phase fault current levels with the GEN-2015-021 generator online were below 23 kA for the 2018SP models and 2026SP models.

The dynamic stability analysis was performed using the three DISIS-2016-002 models 2017 Winter Peak, 2018 Summer Peak, and 2026 Summer Peak. Up to 40 contingencies were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers.

The results of the dynamic stability analysis showed that there were no machine rotor angle damping or transient voltage recovery violations observed in the simulated fault events associated with this modification request study. Additionally, the project was found to stay connected during the other contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

The results of this Study show that the GEN-2015-021 Modification Request does not constitute a material modification.

After the original modification request study was completed, the Interconnection Customer requested a change to project capacity from 184 inverters at 0.1075 MW (19.78 MW) to 184 inverters at 0.1087 MW (20.00 MW), a total project capacity increase of 0.22 MW. The three-phase faults at the POI (Johnson Corner) were simulated to verify the impact of the 0.22 MW increase on system stability. The results showed that there was no additional stability issue observed with the POI faults simulated. As a result, the generator facility modification at the requested capacity of 20.0 MW is not considered a Material Modification.

1.0 Introduction

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Modification Request Impact Study (Study) for GEN-2015-021, an active generation interconnection request with point of interconnection (POI) at the Johnson Corner 115kV Substation.

The GEN-2015-021 project was proposed to interconnect in the Sunflower Electric Power Corporation (SUNC) control area with a combined capacity of 20 MW as shown in Table 1-1 below. Details of the modification request are provided in Section 2.0 below.

Table 1-1: Existing GEN-2015-021 Configuration

Request	Capacity (MW)	Existing Generator Configuration	Point of Interconnection
GEN-2015-021	20	5 x GE LV5 4MW	Johnson Corner 115kV Substation

1.1 Scope

The Study included reactive power, short circuit, and dynamic stability analyses. The methodology, assumptions and results of the analyses are presented in the following five main sections:

1. Project and Modification Request
2. Reactive Power Analysis
3. Short Circuit Analysis
4. Dynamic Stability Analysis
5. Conclusions

The analyses were performed using a set of modified study models developed using the modification request data and the three initial DISIS-2016-002 study models:

1. 2017 Winter Peak (2017WP),
2. 2018 Summer Peak (2018SP), and
3. 2026 Summer Peak (2026SP).

All analyses were performed using the PTI PSS/E version 33.7 software. The results of each analysis are presented in the following sections.

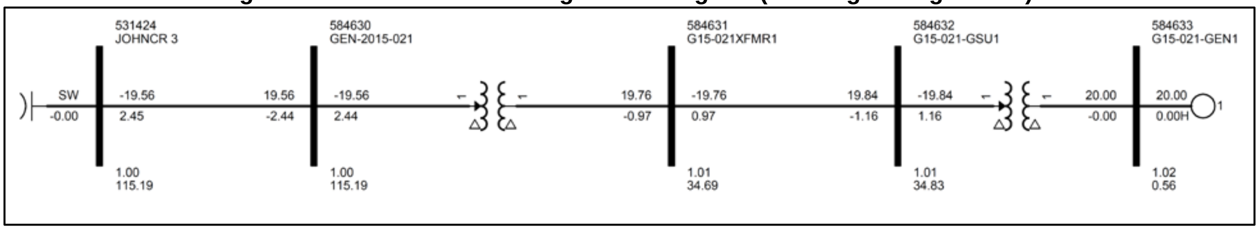
1.2 Study Limitations

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

GEN-2015-021 was originally studied as part of Group 3 in the DISIS-2015-001 study. Figure 2-1 shows the power flow model single line diagram for the existing GEN-2015-021 configuration.

Figure 2-1: GEN-2015-021 Single Line Diagram (Existing Configuration)



The GEN-2015-021 Modification Request included an inverter configuration change to a total of 184 x Sungrow SG125 0.1075MW inverters for a total capacity of 19.78 MW. In addition, the modification request also included changes to the collection system, generation interconnection line and the generator substation transformer. The major modification request changes are shown in Figure 2-2 and Table 2-1 below.

Figure 2-2: GEN-2015-021 Single Line Diagram (New Configuration – 19.78 MW)

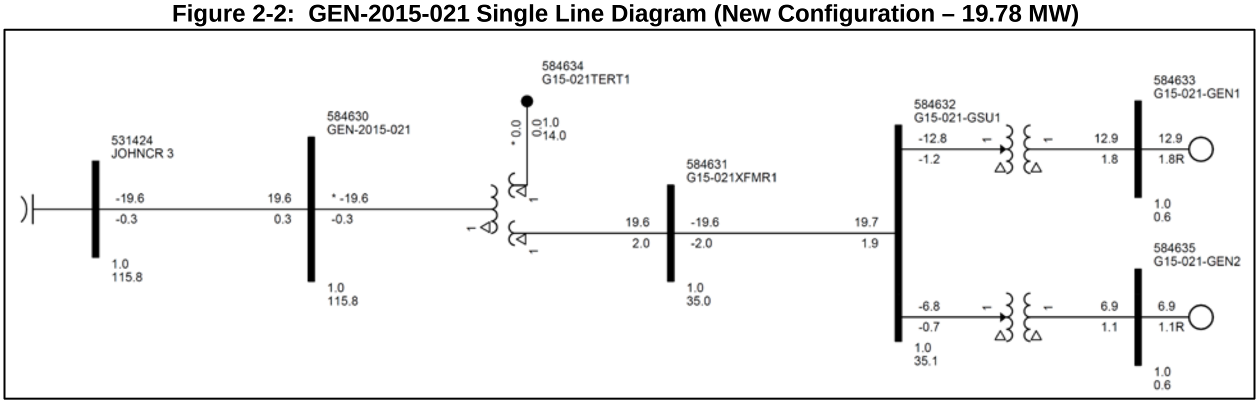


Table 2-1: GEN-2015-021 Modification Request – 19.78 MW

<table>
<tr><th>Facility</th><th>Existing</th><th colspan="2">Modification Request</th></tr>
<tr><td>Point of Interconnection</td><td>Johnson Corner 115 kV Substation (531424)</td><td colspan="2">Johnson Corner 115 kV Substation (531424)</td></tr>
<tr><td>Configuration/Capacity</td><td>5 x GE LV5 4MW = 20 MW</td><td colspan="2">184 x Sungrow SG125 0.1075MW = 19.78 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td>Length = 0.038 miles
R = 0.000090 pu
X = 0.000220 pu
B = 0.000000 pu</td><td colspan="2">Length = 0.038 miles
R = 0.000090 pu
X = 0.000220 pu
B = 0.000000 pu</td></tr>
<tr><td>Main Substation Transformer</td><td>Z = 5.7%, Winding 15 MVA, Rating A 20 MVA, Rating B 25 MVA</td><td colspan="2">Z12 = 7%, Z23 = 2.5%, Z13 = 10.9%, Rating 25 MVA</td></tr>
<tr><td>GSU Transformer</td><td>Gen Equivalent Qty: 5
Z = 6%, Rating 20 MVA</td><td>Gen 1 Equivalent Qty: 120
Z = 5.8%, Rating 15 MVA</td><td>Gen 2 Equivalent Qty: 64
Z = 5.74%, Rating 8 MVA</td></tr>
<tr><td>Equivalent Collector Line</td><td>R = 0.020780 pu
X = 0.006760 pu
B = 0.002120 pu</td><td colspan="2">R = 0.012879 pu
X = 0.003865 pu
B = 0.001391 pu</td></tr>
</table>

Following the completion of the modification request study for the changes shown in Figure 2-2 and Table 2-1, the interconnection customer requested an additional adjustment to the capacity of the generators from the 184 inverters at 0.1075 MW (19.78 MW) to approximately 184 inverters at 0.1087 MW (20.00 MW). This additional change is reflected in Figure 2-3 and Table 2-2 below.

Figure 2-3: GEN-2015-021 Single Line Diagram (New Configuration – 20.0 MW)

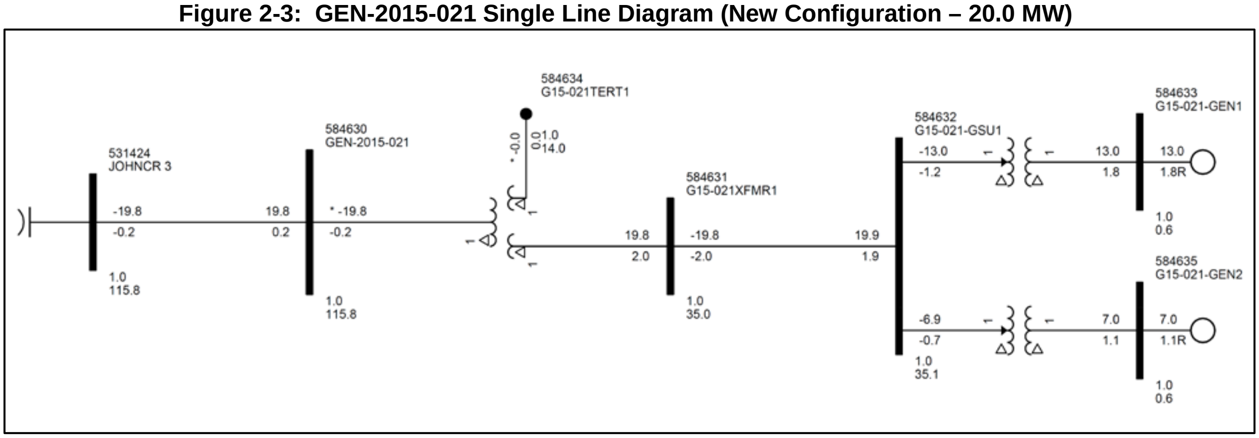


Table 2-2: GEN-2015-021 Modification Request – 20.0 MW

<table>
<tr><th>Facility</th><th>Existing</th><th colspan="2">Modification Request</th></tr>
<tr><td>Point of Interconnection</td><td>Johnson Corner 115 kV Substation (531424)</td><td colspan="2">Johnson Corner 115 kV Substation (531424)</td></tr>
<tr><td>Configuration/Capacity</td><td>5 x GE LV5 4MW = 20 MW</td><td colspan="2">184 x Sungrow SG125 0.1087 MW = 20.0 MW</td></tr>
<tr><td>Generation Interconnection Line</td><td>Length = 0.038 miles
R = 0.000090 pu
X = 0.000220 pu
B = 0.000000 pu</td><td colspan="2">Length = 0.038 miles
R = 0.000090 pu
X = 0.000220 pu
B = 0.000000 pu</td></tr>
<tr><td>Main Substation Transformer</td><td>Z = 5.7%, Winding 15 MVA, Rating A 20 MVA, Rating B 25 MVA</td><td colspan="2">Z12 = 7%, Z23 = 2.5%, Z13 = 10.9%, Rating 25 MVA</td></tr>
<tr><td>GSU Transformer</td><td>Gen Equivalent Qty: 5
Z = 6%, Rating 20 MVA</td><td>Gen 1 Equivalent Qty: 120
Z = 5.8%, Rating 15 MVA</td><td>Gen 2 Equivalent Qty: 64
Z = 5.74%, Rating 8 MVA</td></tr>
<tr><td>Equivalent Collector Line</td><td>R = 0.020780 pu
X = 0.006760 pu
B = 0.002120 pu</td><td colspan="2">R = 0.012879 pu
X = 0.003865 pu
B = 0.001391 pu</td></tr>
</table>

3.0 Reactive Power Analysis

The reactive power analysis, also known as the low or reduced generation analysis, was performed for GEN-2015-021 to determine the reactive power contribution from the project's interconnection line and collector transformer and cables during low-irradiance conditions while the project is still connected to the grid and to size shunt reactors that would reduce the project reactive power contribution to the POI to approximately zero.

3.1 Methodology and Criteria

For the GEN-2015-021 project, the generator was switched out of service while other collector system elements remained in-service. A shunt reactor was tested at the collection substation 115 kV bus to set the MVAr flow into the POI to approximately zero.

3.2 Results

The results from the reactive power analysis showed that the GEN-2015-021 projects required approximately 0.14 MVAr shunt reactance at the high side of the project substation, to reduce the POI MVAr to zero. This represents the contributions from the project collection system. Figure 3-1 illustrates the shunt reactor size required to reduce the POI MVAr to approximately zero. Reactive compensation can be provided either by discrete reactive devices or by the generator itself if it possesses that capability.

Figure 3-1: GEN-2015-021 Single Line Diagram (Shunt Reactor)

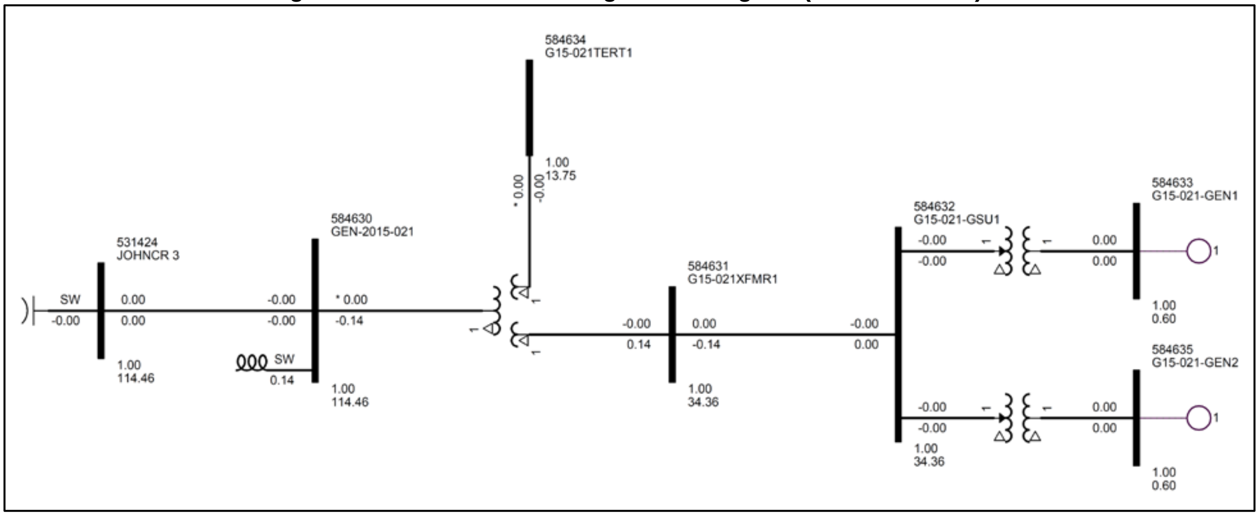


Table 3-1 shows the shunt reactor size determined for the three study models used in the assessment.

Table 3-1: Shunt Reactor Size for Low Irradiance Study

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)		
			17WP	18SP	26SP
GEN-2015-021	531424	Johnson Corner Substation	0.14	0.14	0.14

4.0 Short Circuit Analysis

A short-circuit study was performed using the 2018SP and 2026SP models for GEN-2015-021. The detail results of the short-circuit analysis are provided in Appendix A.

4.1 Methodology

The short-circuit analysis included applying a 3-phase fault on buses up to 5 levels away from the 115 kV POI bus. The PSS/E "Automatic Sequence Fault Calculation (ASCC)" fault analysis module was used to calculate the fault current levels with and without the project online.

4.2 Results

The results of the short circuit analysis for the 2018SP and 2026SP models are summarized in Table 4-1 and Table 4-2 respectively. The maximum increase in fault current was about 1.3%, 0.03 kA. The maximum fault current calculated within 5 buses with GEN-2015-021 was less than 22 kA and 23 kA for the 2018SP and 2026SP models respectively. This is expected as solar inverters do not contribute to fault current levels.

Table 4-1: 2018SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	3.9	0.03	1.3%
115	21.9	0.03	1.2%
Max	**21.9**	**0.03**	**1.3%**

Table 4-2: 2026SP Short Circuit Results

Voltage (kV)	Max. Current (kA)	Max kA Change	Max %Change
69	3.9	0.02	1.1%
115	22.6	0.03	1.1%
Max	**22.6**	**0.03**	**1.1%**

5.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the inverter configuration change and other modifications to the GEN-2015-021 project. The analysis was performed according to SPP's Disturbance Performance Requirements shown in Appendix B. The modification details are described in Section 2.0 above and the dynamic modeling data is provided in Appendix C. The simulation plots can be found in Appendix D.

5.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested 184 x Sungrow SG125 0.1075MW inverters for the GEN-2015-021 generating facilities. This stability analysis was performed using PTI's PSS/E version 33.7 software.

The stability models were developed using the models from DISIS-2016-002 for Group 3. The modifications requested to project GEN-2015-021 were used to create modified stability models for this impact study.

The modified dynamic model data for the DISIS-2016-002 Group 3 request, GEN-2015-021, is provided in Appendix C. 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-2015-021 and other equally and prior queued projects in Group 3. In addition, voltages of five (5) buses away from the POI of GEN-2015-021 were monitored and plotted. The machine rotor angle for synchronous machines and speed for asynchronous machines within this study area including 520 (AEPW), 524 (OKGE), 525(WFEC), 526 (SPS), 531 (MIDW), 534 (SUNC), 536 (WERE), 640 (NPPD), 645 (OPPD), 650 (LES), 652 (WAPA) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

5.2 Fault Definitions

Aneden selected a subset of the fault events simulated specifically for GEN-2015-021 in the DISIS-2015-001 Group 3 study and included additional faults 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 faults with stuck breakers. The simulated faults are listed and described in Table 5-1 below. These contingencies were applied to the modified 2017 Winter Peak, 2018 Summer Peak, and the 2026 Summer Peak models.

Table 5-1: Fault Definitions

Fault ID	Fault Descriptions
FLT56-3PH	3 phase fault on the Johnson Corner (531424) to Johnson (531381) 115kV line ckt 1, near Johnson Corner. a. Apply fault at the Johnson Corner 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT57-3PH	3 phase fault on the Johnson Corner (531424) to Bear Creek (531473) 115kV line ckt 1, near Johnson Corner. a. Apply fault at the Johnson Corner 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT58-3PH	3 phase fault on the Syracuse (531437) to Bear Creek (531473) 115kV line ckt 1, near Syracuse. a. Apply fault at the Syracuse 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT59-3PH	3 phase fault on the Syracuse (531437) to Tribune (531439) 115kV line ckt 1, near Syracuse. a. Apply fault at the Syracuse 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT60-3PH	3 phase fault on the Syracuse (531437) to Williamson (531440) 115kV line ckt 1, near Syracuse. a. Apply fault at the Syracuse 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT61-3PH	3 phase fault on the Tribune Switch (531438) to Palmer (531431) 115kV line ckt 1, near Tribune Switch. a. Apply fault at the Tribune Switch 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT62-3PH	3 phase fault on the Tribune Switch (531438) to Selkirk (531434) 115kV line ckt 1, near Tribune Switch. a. Apply fault at the Tribune Switch 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT63-3PH	3 phase fault on the Tribune Switch (531438) to Tribune (531439) 115kV line ckt 1, near Tribune Switch. a. Apply fault at the Tribune Switch 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT64-3PH	3 phase fault on the Fletcher (531420) to PK_GOAB (531400) 115kV line ckt 1, near Fletcher. a. Apply fault at the Fletcher 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT65-3PH	3 phase fault on the Fletcher (531420) to Williamson (531440) 115kV line ckt 1, near Fletcher. a. Apply fault at the Fletcher 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT66-3PH	3 phase fault on the Fletcher (531420) to Holcomb (531448) 115kV line ckt 1, near Fletcher. a. Apply fault at the Fletcher 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.

Table 5-1 continued

Fault ID	Fault Descriptions
FLT67-3PH	3 phase fault on the Pioneer (531391) to Hickock (531378) 115kV line ckt 1, near Pioneer. a. Apply fault at the Pioneer 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT68-3PH	3 phase fault on the Pioneer (531391) to PK_GOAB (531400) 115kV line ckt 1, near Pioneer. a. Apply fault at the Pioneer 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT69-3PH	3 phase fault on the Pioneer (531391) to Grant Tap (531483) 115kV line ckt 1, near Pioneer. a. Apply fault at the Pioneer 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT70-3PH	3 phase fault on the Pioneer (531391) to Ulysses Plant (531490) 115kV line ckt 1, near Pioneer. a. Apply fault at the Pioneer 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT71-3PH	3 phase fault on the Pioneer Tap (531392) to CMX Tap (531203) 115kV line ckt 1, near Pioneer Tap. a. Apply fault at the Pioneer Tap 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT72-3PH	3 phase fault on the Pioneer Tap (531392) to Plymel (531393) 115kV line ckt 1, near Pioneer Tap. a. Apply fault at the Pioneer Tap 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT73-3PH	3 phase fault on the Pioneer Tap (531392) to Sublette (531398) 115kV line ckt 1, near Pioneer Tap. a. Apply fault at the Pioneer Tap 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT74-3PH	3 phase fault on the Pioneer Tap (531392) to Satanta Tap (531442) 115kV line ckt 1, near Pioneer Tap. a. Apply fault at the Pioneer Tap 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT1001-SB	**Stuck Breaker at Johnson 115kV (531381)** a. Apply single phase fault at Johnson. b. Clear fault after 16 cycles and trip the following elements c. Johnson 115kV bus
FLT1002-SB	**Stuck Breaker at Johnson Corner 69kV (531383)** a. Apply single phase fault at Johnson Corner. b. Clear fault after 16 cycles and trip the following elements c. Johnson Corner 69kV bus
FLT1003-SB	**Stuck Breaker at Syracuse 115kV (531437)** a. Apply single phase fault at Syracuse. b. Clear fault after 16 cycles and trip the following elements c. Syracuse 115kV bus

Table 5-1 continued

Fault ID	Fault Descriptions
FLT9001-3PH	3 phase fault on the JOHNCR2 (531383) to MANTERT2 (531475) 69 kV line circuit 1, near JOHNCR2. a. Apply fault at the JOHNCR2 69 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT9002-3PH	3 phase fault on the MANTERT2 (531475) to MANTER 2 (531382) 69 kV line circuit 1, near MANTERT2. a. Apply fault at the MANTERT2 69 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT9003-3PH	3 phase fault on the MANTERT2 (531475) to RICHFLD2 (531474) 69 kV line circuit 1, near MANTERT2. a. Apply fault at the MANTERT2 69 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT9004-3PH	3 phase fault on the BEARCRK3 (531473) to SYRACUS3 (531437) 115 kV line circuit 1, near BEARCRK3. a. Apply fault at the BEARCRK3 115 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	3 phase fault on the WILLIAM3 (531440) to FLETCHR3 (531420) 115 kV line circuit 1, near WILLIAM3. a. Apply fault at the WILLIAM3 115 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT9006-3PH	3 phase fault on JOHNCR 3 115 kV (531424) to JOHNCR 2 69 kV (531383) to JOHNCR 1 13.8 kV (531257) XFMR, near JOHNCR 3 115 kV. a. Apply fault at the JOHNCR 3 115 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT9007-3PH	3 phase fault on the JOHNSON2 (531381) to BIG BOW 3 (531491) 115 kV line circuit 1, near JOHNSON2. a. Apply fault at the JOHNSON2 115 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT9008-3PH	3 phase fault on the BIG BOW 3 (531491) to ULYSPLT3 (531490) kV line circuit 1, near BIG BOW 3. a. Apply fault at the BIG BOW 3 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT9009-3PH	3 phase fault on the ULYSPLT3 (531490) to PIONEER3 (531391) kV line circuit 1, near ULYSPLT3. a. Apply fault at the ULYSPLT3 kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT59-PO1	**Prior Outage of Johnson Corner (531424) to Johnson (531381) 115kV Circuit 1;** 3 phase fault on the Syracuse (531437) to Tribune (531439) 115kV line ckt 1, near Syracuse. a. Apply fault at the Syracuse 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.

Table 5-1 continued

Fault ID	Fault Descriptions
FLT60-PO1	**Prior Outage of Johnson Corner (531424) to Johnson (531381) 115kV Circuit 1;** 3 phase fault on the Syracuse (531437) to Williamson (531440) 115kV line ckt 1, near Syracuse. a. Apply fault at the Syracuse 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT9006-PO1	**Prior Outage of Johnson Corner (531424) to Johnson (531381) 115kV Circuit 1;** 3 phase fault on JOHNCR 3 115 kV (531424) to JOHNCR 2 69 kV (531383) to JOHNCR 1 13.8 kV (531257) XFMR, near JOHNCR 3 115 kV. a. Apply fault at the JOHNCR 3 115 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT67-PO2	**Prior Outage of Johnson Corner (531424) to Bear Creek (531473) 115kV Circuit 1;** 3 phase fault on the Pioneer (531391) to Hickock (531378) 115kV line ckt 1, near Pioneer. a. Apply fault at the Pioneer 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT68-PO2	**Prior Outage of Johnson Corner (531424) to Bear Creek (531473) 115kV Circuit 1;** 3 phase fault on the Pioneer (531391) to PK_GOAB (531400) 115kV line ckt 1, near Pioneer. a. Apply fault at the Pioneer 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT69-PO2	Prior Outage of Johnson Corner (531424) to Bear Creek (531473) 115kV Circuit 1; 3 phase fault on the Pioneer (531391) to Grant Tap (531483) 115kV line ckt 1, near Pioneer. a. Apply fault at the Pioneer 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT9006-PO2	**Prior Outage of Johnson Corner (531424) to Bear Creek (531473) 115kV Circuit 1;** 3 phase fault on JOHNCR 3 115 kV (531424) to JOHNCR 2 69 kV (531383) to JOHNCR 1 13.8 kV (531257) XFMR, near JOHNCR 3 115 kV. a. Apply fault at the JOHNCR 3 115 kV bus. b. Clear fault after 5 cycles and trip the faulted transformer.
FLT56-PO3	**Prior Outage of JOHNCR 3 115 kV (531424) to JOHNCR 2 69 kV (531383) to JOHNCR 1 13.8 kV (531257) XFMR Circuit 1;** 3 phase fault on the Johnson Corner (531424) to Johnson (531381) 115kV line ckt 1, near Johnson Corner. a. Apply fault at the Johnson Corner 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.
FLT57-PO3	**Prior Outage of JOHNCR 3 115 kV (531424) to JOHNCR 2 69 kV (531383) to JOHNCR 1 13.8 kV (531257) XFMR Circuit 1;** 3 phase fault on the Johnson Corner (531424) to Bear Creek (531473) 115kV line ckt 1, near Johnson Corner. a. Apply fault at the Johnson Corner 115kV bus. b. Clear fault after 5 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 5 cycles, then trip the line in (b) and remove fault.

5.3 Results

Table 5-2 shows the results of the fault events simulated for each of the models. The associated stability plots are provided in Appendix D.

There were no damping or voltage recovery violations 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.

Table 5-2: GEN-2015-021 Dynamic Stability Results

Fault ID	17W			18S			26S		
	Volt. Recovery	Volt. Violation	Stability	Volt. Recovery	Volt. Violation	Stability	Volt. Recovery	Volt. Violation	Stability
FLT56-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT57-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT58-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT59-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT60-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT61-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT62-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT63-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT64-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT65-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT66-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT67-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT68-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT69-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT70-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT71-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT72-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT73-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT74-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT59-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT60-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO1	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT67-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT68-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Table 5-2 continued

Fault ID	17W			18S			26S		
	Volt. Recovery	Volt. Violation	Stability	Volt. Recovery	Volt. Violation	Stability	Volt. Recovery	Volt. Violation	Stability
FLT69-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT9006-PO2	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT56-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable
FLT57-PO3	Pass	Pass	Stable	Pass	Pass	Stable	Pass	Pass	Stable

Additional stability simulations were performed for the 20.0 MW configuration described in Section 2.0 above, 184 inverters at 0.1087 MW capacity each. The stability simulations included a no-disturbance condition and the two three-phase POI faults, FLT56 and FLT57. The results showed that with the total project capacity increase from 19.78 MW, included in the original modification request, to 20.0 MW did not cause any adverse stability impacts. The results of the additional stability results are provided at the end of Appendix D.

6.0 Conclusions

The Interconnection Customer for GEN-2015-021 requested a Modification Request Impact Study to assess the impact of the inverter and facility changes to a configuration with a total of 184 x Sungrow SG125 0.1075MW inverters for a total capacity of 19.78 MW. In addition, the modification request included changes to the collection system and the generator substation transformer.

A power factor analysis was not performed as there was no change in the point of interconnection for GEN-2015-021.

The results of the reactive power analysis, also known as the low or reduced generation analysis, performed using all three models showed that the combined GEN-2015-021 project may require an 0.14 MVAr shunt reactor on the 115kV bus of the project substation. The shunt reactor is needed to reduce the reactive power transfer at the POI to approximately zero during low/no irradiance conditions while the generation interconnection project remains connected to the grid.

The results from the short circuit analysis showed that the maximum change in the fault currents in the immediate systems at or near GEN-2015-021 was approximately 0.03 kA for both the 2018SP and 2026SP models. All three-phase current levels with the GEN-2015-021 generator online were below 22 kA and 23 kA for the 2018SP models and 2026SP models respectively.

The results of the dynamic stability analysis showed that there was no violation associated with the GEN-2015-021 modification. Additionally, the project was found to stay connected during the other contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

The results of this Study show that the GEN-2015-021 Modification Request does not constitute a material modification.

After the original modification request study was completed, the Interconnection Customer requested a change to project capacity from 184 inverters at 0.1075 MW (19.78 MW) to 184 inverters at 0.1087 MW (20.00 MW), a total project capacity increase of 0.22 MW. The three-phase faults at the POI (Johnson Corner), faults FLT56 and FLT57, were simulated to verify the impact of the 0.22 MW increase on system stability. The results showed that there was no additional stability issue observed with the POI faults simulated. As a result, the generator facility modification at the requested capacity of 20.0 MW is not considered a Material Modification.