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SPP Southwest Power Pool

Report On

GEN-2021-SR8
Surplus Service Impact Study

Revision R1

Date of Submittal
December 2, 2021

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPENDICES

Revision History

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION
12/2/2021	Aneden Consulting	Initial Report Issued.

Executive Summary

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Surplus Interconnection Service Impact Study (Study) for GEN-2021-SR8 to utilize the Surplus Interconnection Service provided by GEN-2016-153 at its existing point of interconnection (POI), the Viola 345 kV substation in the Westar Energy (WERE) control area.

GEN-2021-SR8, the proposed Surplus Generating Facility (SGF), will be located at the existing main collection substation used by GEN-2016-153, the Existing Generating Facility (EGF).

The EGF project has an effective Generator Interconnection Agreement (GIA) with a POI capacity of 134 MW and is making 42 MW of Surplus Interconnection Service available at its point of interconnection. Per the SPP Open Access Transmission Tariff (OATT), the amount of Surplus Interconnection Service available to be used by the SGF is limited by the amount of Interconnection Service granted to the EGF at the same POI. In addition, the Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades.

The SGF proposed configuration consists of 12 x SMA SC4000-UP 3.76 MW batteries for total capacity of 45.12 MW as shown in Table ES-1 below along with the EGF details. As the requested Surplus Interconnection Service is for 42 MW, the injection amount of the SGF must be limited to 42 MW at the POI. The combined generation from both the SGF and the EGF may not exceed 134 MW at the POI, which is the total Interconnection Service amount currently granted to the EGF. GEN-2021-SR8 includes the use of a Power Plant Controller (PPC) to limit the power injection as required.

The SGF configuration is captured in Table ES-2 below.

Table ES-1: EGF & SGF Configuration

Request	Capacity (MW)	Generator Configuration	Point of Interconnection
GEN-2021-SR8 (SGF)	42	12 x SMA SC4000-UP 3.76 MW =45.12 MW PPC to limit generator output to 42 MW	Viola 345 kV (532798)
GEN-2016-153 (EGF)	134	67 x Vestas V110 2.0 MW Mk10D= 134 MW	Viola 345 kV (532798)

Table ES-2: SGF Interconnection Configuration

Facility	GEN-2021-SR8	
Point of Interconnection	Viola 345 kV (532798)	
Configuration/Capacity	12 x SMA SC4000-UP 3.76 MW = 45.12 MW (PPC to limit generator output to 42 MW) PPC to limit total POI injection w/ GEN-2016-153 to 134 MW	
Generation Interconnection Line (shared with EGF and unchanged)	GEN-2016-153 to G16-153-TAP: Length = 2.2 miles R = 0.000360 pu X = 0.001130 pu B = 0.000000 pu	G16-153-TAP to Viola: Length = 23.9 miles R = 0.001190 pu X = 0.014413 pu B = 0.167863 pu
Main Substation Transformer[1] (shared with EGF and unchanged)	X = 9.7897%, R = 0.457%, Winding MVA = 84 MVA, Rating MVA = 140 MVA	
Equivalent GSU Transformer[1]	Gen 1 Equivalent Qty: 12 (SMASC167) X = 7.454%, R = 0.828%, Winding MVA = 48 MVA, Rating MVA = 48 MVA	
Equivalent Collector Line[2]	R = 0.006226 pu X = 0.006826 pu B = 0.004239 pu	

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

Since the EGF and SGF are both non-synchronous fuel types, SPP determined that power flow analysis is not required because the EGF was studied previously under the required reliability conditions.

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

Aneden performed the analyses using the study data provided by the SGF based on the DISIS-2017-001 Group 8[1] study models:

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

Aneden reviewed the GIRs that shared the same POI, Viola 345 kV, and updated as applicable based on SPP's confirmation of the latest project configurations. As a result, Aneden updated the

[1] This cluster group has been reallocated to the new Regional Study Group in the current SPP GI Queue. https://opsportal.spp.org/documents/studies/SPPRegionalGroups.pdf

GEN-2010-005 configuration 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 SGF project needed an approximately 0.4 MVAr shunt reactor at the project substation, to reduce the POI MVAr to zero when the GEN-2010-005 Phase II, GEN-2007-025 & GEN-2010-005 Phase I, and EGF projects have shunt reactors compensating their charging effects. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during reduced generation conditions. The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

The results from the short circuit analysis compared the existing DISIS case (EGF online, SGF not included) 2021SP and 2028SP models to the SGF study case (EGF and SGF online) 2021SP and 2028SP models. The maximum contribution to three-phase fault currents in the immediate transmission systems due to the addition of the SGF was not greater than 0.05 kA[2]. All three-phase fault current levels within 5 buses of the POI with the EGF and SGF generators online were below 34 kA for the 2021SP models 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 with two dispatch scenarios. In the first scenario, the SGF was online at 42 MW while the EGF was offline and disconnected. The second scenario included a combination of the SGF dispatched to maximum at 42 MW and the EGF picking up the remaining 92 MW for a total combination of 134 MW. Up to 60 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

The results of the dynamic stability analysis showed that there were numerous existing base case issues that were mitigated prior to studying the SGF project. These case adjustments are listed in Section 5.1. In addition, there were two types of existing stability oscillations. First, multiple faults across all four cases caused the GRNTWDG units (515660 & 515661) to have high frequency oscillations. Second, EFD oscillations were found for every fault studied in the 21LL case from the REDBUD units (514899, 514900, 514905, 514910, 514940, 514942). These issues were observed in the DISIS, Scenario 1, and Scenario 2 cases so they were not attributed to the SGF project.

There were no damping or voltage recovery violations attributed to the GEN-2021-SR8 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.

[2] For buses not on the generation interconnection line

The results of the study showed that the Surplus Interconnection Service Request by GEN-2021-SR8 did not negatively impact the reliability of the Transmission System. There were no additional Interconnection Facilities or Network Upgrades identified by the analyses.

SPP has determined that GEN-2021-SR8 may utilize the requested 42 MW of Surplus Interconnection Service provided by the EGF. The combined generation from both the SGF and the EGF may not exceed 134 MW at the POI, which is the total Interconnection Service amount currently granted to the EGF.

The customer must install monitoring and control equipment as needed to ensure that the SGF does not exceed the granted surplus amount and to ensure that combination of the SGF and EGF power injected at the POI does not exceed the Interconnection Service amount listed in the EGF's GIA. The monitoring and control scheme will need to be reviewed by SPP and the TO and documented in Appendix C of the GIA.

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

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

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

1.0 Scope of Study

Aneden Consulting (Aneden) was retained by the Southwest Power Pool (SPP) to perform a Surplus Service Impact Study (Study) for GEN-2021-SR8, the Surplus Generating Facility (SGF). A Surplus Service Impact Study is performed to identify the impact of the Surplus Interconnection Service on the transmission system reliability and any additional Interconnection Facilities necessary pursuant to the SPP Generator Interconnection Procedures ("GIP") contained in Attachment V Section 3.3 of the SPP Open Access Transmission Tariff (OATT). The amount of Surplus Interconnection Service available to be used by the SGF is limited by the amount of Interconnection Service granted to the existing interconnection customer for the Existing Generating Facility (EGF) at the same POI. The Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades. The required scope of the study is dependent upon the EGF and SGF specifications. The criteria sections below include the basis of the analyses included in 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 Charging Current Compensation Analysis

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

1.2 Short Circuit Analysis

SPP requires that a short circuit analysis be performed to determine the maximum available fault current requiring interruption by protective equipment with both the SGF and EGF online, along with the amount of increase in maximum fault current due to the addition of the SGF. The analysis is performed on two scenarios, the existing cases with EGF as dispatched and SGF offline, and the modified cases with both EGF and SGF dispatched.

1.3 Stability Analysis

SPP requires that a dynamic stability analysis be performed to determine whether the SGF, EGF, and the transmission system will remain stable and within applicable criteria. Dynamic stability analysis is performed on two dispatch scenarios, the first where the SGF is dispatched to 100% with the EGF offline and disconnected, and the second where the EGF dispatch is reduced by the amount of Surplus Interconnection Service and the SGF is dispatched to 100%. Any mitigations, if required to address any stability issues, will be classified according to type of need, Interconnection Facility, Network Upgrade or Contingent Facility.

1.4 Power Flow

The power flow (thermal/voltage) analyses may be performed as necessary to ensure that all required reliability conditions are studied. If the EGF was not studied under off-peak conditions, off-peak steady state analyses shall be performed to the required level necessary to demonstrate reliable operation of the Surplus Interconnection Service. If the original system impact study is not available for the Interconnection Service, both off-peak and peak analysis may need to be performed for the EGF associated with the request.

An SGF that includes a fuel type (synchronous/non-synchronous) different from the EGF will require a power flow analysis to study impacts resultant from changes in dispatch to all equal and lower queued requests. Any mitigations, if required to address any thermal or voltage violations, will be evaluated to determine if they are Interconnection Facility, Network Upgrade or Contingent Facility needs.

Since the EGF and SGF are both non-synchronous fuel types, SPP determined that power flow analysis is not required because the EGF was studied previously under the required reliability conditions.

1.5 Necessary Interconnection Facilities & Network Upgrades

The SPP OATT[3] states that the reactive power, short circuit/fault duty, stability, and steady-state analyses (where applicable) for the Surplus Interconnection Service will identify any additional Interconnection Facilities necessary. In addition, the analyses will determine if any Network Upgrades are required for mitigation. The Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades.

1.6 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.

[3] SPP Open Access Transmission Tariff Section 3.34.1

2.0 Surplus Interconnection Service Request

The GEN-2021-SR8 Interconnection Customer has requested a Surplus Interconnection Service Impact Study (Study) for GEN-2021-SR8 to utilize the Surplus Interconnection Service provided by GEN-2016-153 at its existing point of interconnection (POI), the Viola 345 kV substation in the Westar Energy (WERE) control area.

GEN-2021-SR8, the proposed SGF, will be located at the existing main collection substation used by GEN-2016-153, the EGF.

The EGF project has an effective GIA with a POI capacity of 134 MW and is making 42 MW of Surplus Interconnection Service available at its point of interconnection. Per the SPP OATT the amount of Surplus Interconnection Service available to be used by the SGF is limited by the amount of Interconnection Service granted to the EGF at the same POI. In addition, the Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades.

At the time of the posting of this report, GEN-2016-153 (EGF) is an active interconnection request at the same POI (Viola 345 kV) with a queue status of "IA FULLY EXECUTED/ON SCHEDULE". GEN-2016-153 is a wind farm, has a maximum summer and winter queue capacity of 134 MW, and has Energy Resource Interconnection Service (ERIS).

GEN-2016-153, the EGF, was originally studied as part of Group 8 in the DISIS-2016-002 study. Figure 2-1 shows the power flow model single line diagram for the EGF configuration. Aneden reviewed the GIRs that shared the same POI, Viola 345 kV, and updated as applicable based on SPP's confirmation of the latest project configurations. As a result, Aneden updated the GEN-2010-005 configuration in the base models.

The SGF proposed configuration consists of 12 x SMA SC4000-UP 3.76 MW batteries for total capacity of 45.12 MW as shown in Table 2-1 below along with the EGF details. As the requested Surplus Interconnection Service is for 42 MW, the injection amount of the SGF must be limited to 42 MW at the POI. The combined generation from both the SGF and the EGF may not exceed 134 MW at the POI, which is the total Interconnection Service amount currently granted to the EGF. GEN-2021-SR8 includes the use of a Power Plant Controller (PPC) to limit the power injection as required. The proposed SGF configuration is captured in Figure 2-2 and Table 2-2 below.

Table 2-1: EGF & SGF Configuration

Request	Capacity (MW)	Generator Configuration	Point of Interconnection
GEN-2021-SR8 (SGF)	42	12 x SMA SC4000-UP 3.76 MW =45.12 MW PPC to limit generator output to 42 MW	Viola 345 kV (532798)
GEN-2016-153 (EGF)	134	67 x Vestas V110 2.0 MW Mk10D= 134 MW	Viola 345 kV (532798)

Figure 2-1: GEN-2016-153 & POI Projects Single Line Diagram (EGF Existing Configuration)

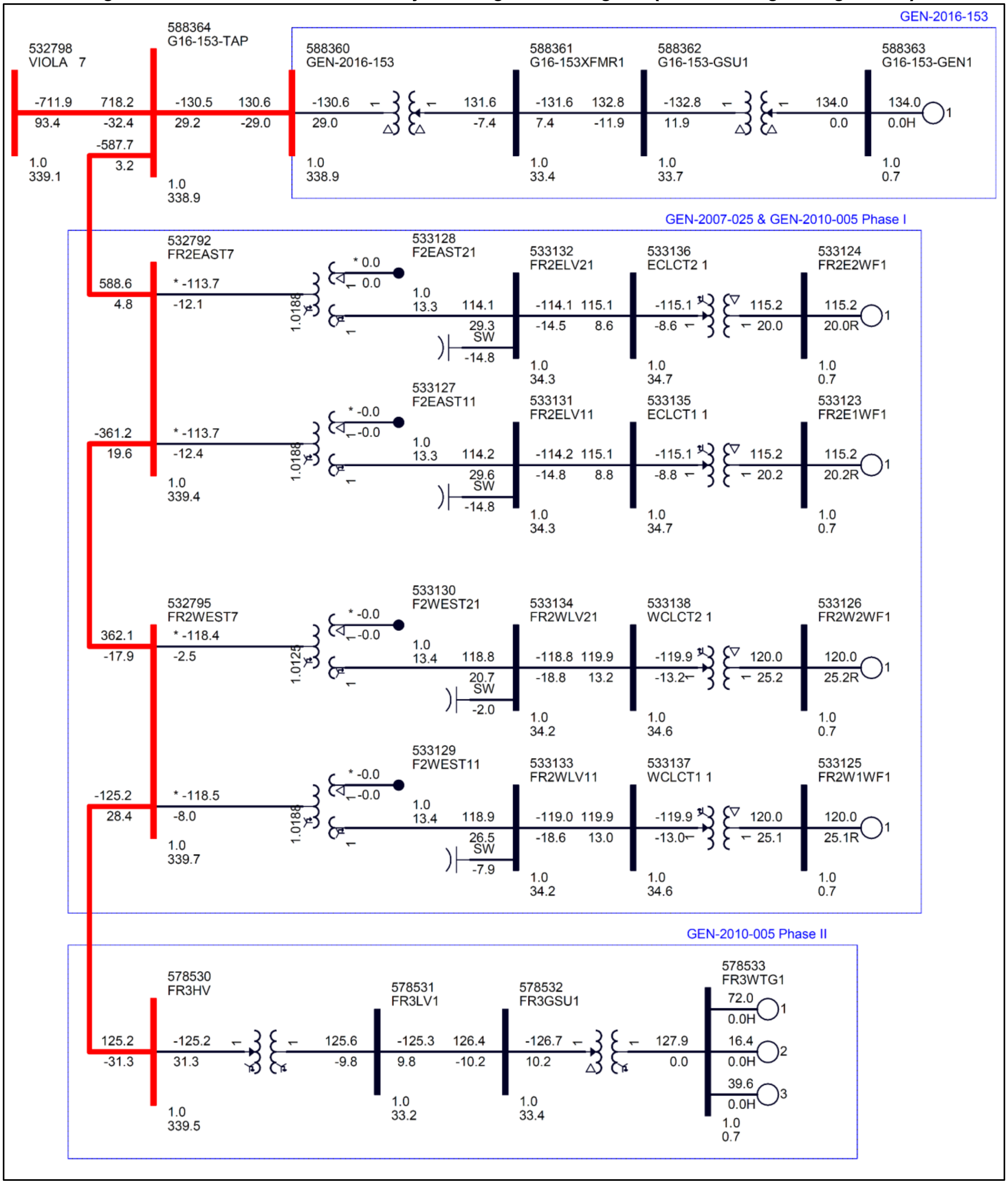


Figure 2-2: GEN-2016-153 & GEN-2021-SR8 (& POI Projects) Single Line Diagram (EGF & SGF Configuration)

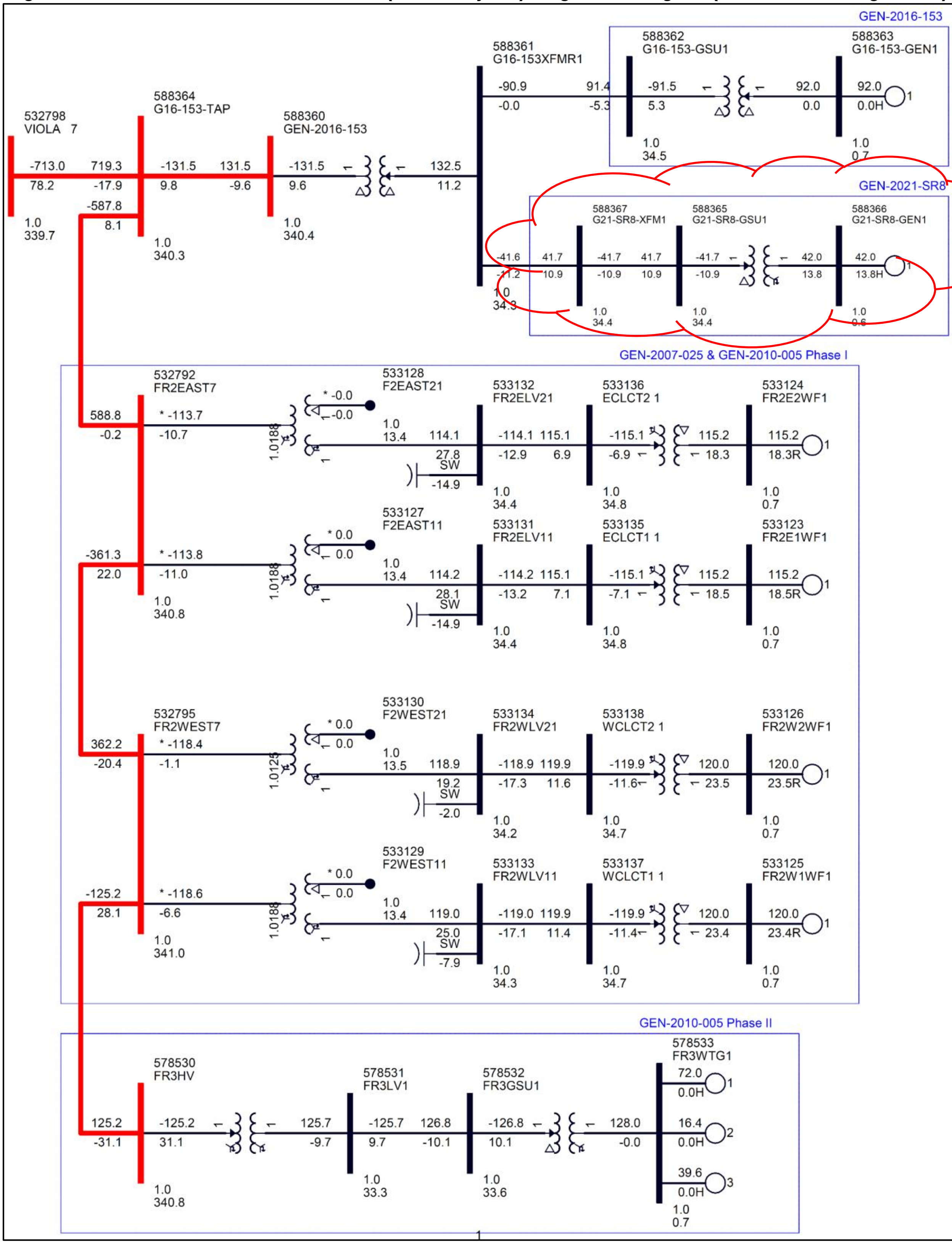


Table 2-2: SGF Interconnection Configuration

<table>
<tr><th>Facility</th><th colspan="2">GEN-2021-SR8</th></tr>
<tr><td>Point of Interconnection</td><td colspan="2">Viola 345 kV (532798)</td></tr>
<tr><td>Configuration/Capacity</td><td colspan="2">12 x SMA SC4000-UP 3.76 MW = 45.12 MW (PPC to limit generator output to 42 MW)
PPC to limit total POI injection w/ GEN-2016-153 to 134 MW</td></tr>
<tr><td>Generation Interconnection Line (shared with EGF and unchanged)</td><td>GEN-2016-153 to G16-153-TAP:
Length = 2.2 miles
R = 0.000360 pu
X = 0.001130 pu
B = 0.000000 pu</td><td>G16-153-TAP to Viola:
Length = 23.9 miles
R = 0.001190 pu
X = 0.014413 pu
B = 0.167863 pu</td></tr>
<tr><td>Main Substation Transformer[1] (shared with EGF and unchanged)</td><td colspan="2">X = 9.7897%, R = 0.457%,
Winding MVA = 84 MVA,
Rating MVA = 140 MVA</td></tr>
<tr><td rowspan="2">Equivalent GSU Transformer[1]</td><td colspan="2">Gen 1 Equivalent Qty: 12 (SMASC167)</td></tr>
<tr><td colspan="2">X = 7.454%, R = 0.828%,
Winding MVA = 48 MVA,
Rating MVA = 48 MVA</td></tr>
<tr><td>Equivalent Collector Line[2]</td><td colspan="2">R = 0.006226 pu
X = 0.006826 pu
B = 0.004239 pu</td></tr>
</table>

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

2.1 POI Injection Comparison

The real power injection at the POI was measured in PSS/E for the EGF configuration alone and for the EGF + SGF configuration with a total generator output of 134 MW. The difference in the POI injection was then compared for information.

There was an insignificant change (increase of 0.15%) in the real power output at the POI between the EGF configuration and EGF + SGF configuration as shown in Table 2-3. The MW shown includes injections from both the GEN-2016-153 and GEN-2021-SR8 projects and nearby projects GEN-2007-025 and GEN-2010-005 which share the gen-tie line with the EGF and SGF.

Table 2-3: POI Injection Comparison

Interconnection Request	EGF POI Injection from Project (MW)	SGF + EGF POI Injection from Project (MW)	POI Injection Difference %
GEN-2021-SR8	711.9*	713.0*	0.15%

*The total MW amount includes the GEN-2007-025 & GEN-2010-005 projects which share the gen-tie line

3.0 Charging Current Compensation Analysis

The charging current compensation analysis was performed for GEN-2021-SR8 to determine the capacitive charging effects required due to the SGF 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.

3.1 Methodology and Criteria

In order to determine the required shunt reactor the SGF would need to compensate for the current charging attributed to its collection system, the charging current compensation analysis for GEN-2010-005 Phase II, GEN-2007-025 & GEN-2010-005 Phase I, and the EGF were determined step-by-step in that order. Once the incremental shunt reactor sizes for these projects were determined, the SGF incremental shunt reactor size was then calculated.

For each of the shunt reactor sizes calculated, all project generators and reactive devices were switched offline while other collector system elements remained in-service as required. The collection system that was switched online depended on which project shunt reactor size was being calculated. 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).

3.2 Results

Per the methodology described above, the shunt reactor sizes were determined for GEN-2010-005 Phase II, GEN-2007-025 & GEN-2010-005 Phase I, and the EGF in that order prior to calculating the shunt reactor size for the SGF. The shunt reactor sizes were found to be 5.5 MVAr for GEN-2010-005 Phase II, 64.7 MVAr for GEN-2007-025 & GEN-2010-005 Phase I, and 5.9 MVAr for the EGF.

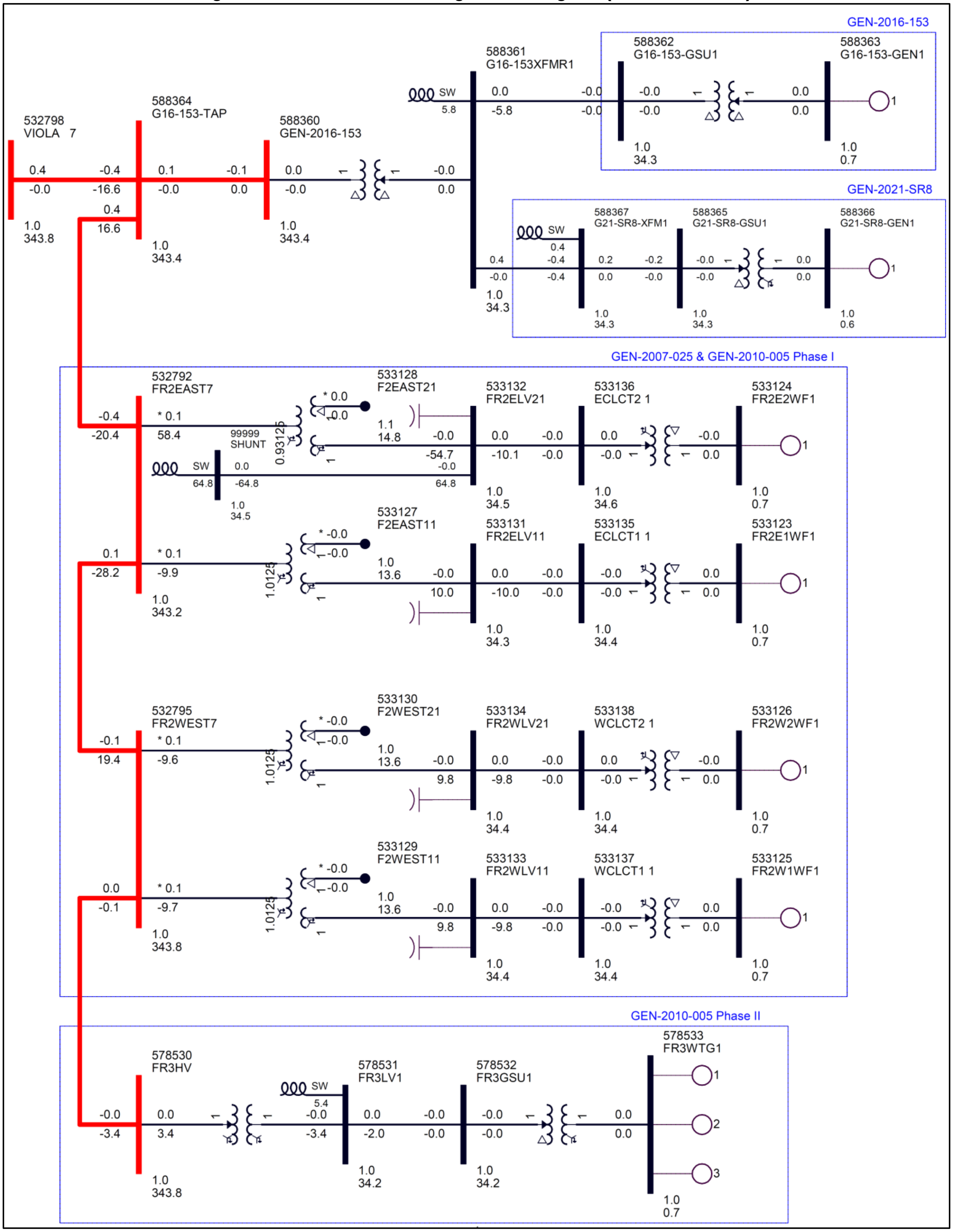
The results from the analysis showed that the SGF needed an approximately 0.4 MVAr shunt reactor at the SGF substation, to reduce the POI MVAr to zero with the pre-determined shunt reactors for GEN-2010-005 Phase II, GEN-2007-025 & GEN-2010-005 Phase I, and the EGF in-service. Figure 3-1 illustrates the shunt reactor sizes needed to reduce the POI MVAr to approximately zero. The final shunt reactor requirements for the SGF are shown in Table 3-1.

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 3-1: Shunt Reactor Size for Reduced Generation Study

Machine	POI Bus Number	POI Bus Name	Reactor Size (MVAr)			
			19WP	21LL	21SP	28SP
GEN-2021-SR8 (SGF)	532798	Viola 345 kV	0.4	0.4	0.4	0.4

Figure 3-1: GEN-2021-SR8 Single Line Diagram (Shunt Reactors)



4.0 Short Circuit Analysis

A short circuit study was performed using the 2021SP and 2028SP models to determine the maximum available fault current requiring interruption by protective equipment with both the SGF and EGF for each bus in the relevant subsystem, and the amount of increase in maximum fault current due to the addition of the SGF. The detailed results of the short circuit analysis are provided in Appendix B.

4.1 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 the SGF online. The existing DISIS cases (with the GEN-2010-005 project updated) were studied with the EGF as dispatched before the SGF was connected. The second scenario was studied with the EGF dispatch reduced by the amount of Surplus Interconnection Service and the SGF dispatched to 100% to determine the impact of the SGF.

4.2 Results

The results of the short circuit analysis compare the existing DISIS case (EGF online, SGF not included) 2021SP and 2028SP models to the selected dispatch case (EGF = 92 MW, SGF = 42 MW) 2021SP and 2028SP models in Table 4-1 through Table 4-3. The POI bus fault current magnitudes are provided in Table 4-1 showing a maximum fault current of 14.46 kA with the EGF and SGF online. The addition of the SGF configuration increased the POI bus fault current by 0.05 kA.

The maximum fault current calculated within 5 buses of the POI was less than 34 kA for the 2021SP and 2028SP models respectively. The maximum contribution to three-phase fault currents due to the addition of the SGF was about 0.3% and 0.05 kA[4].

Table 4-1: POI Short Circuit Comparison Results

Case	DISIS EGF Current (kA)	SGF & EGF Current (kA)	Max kA Change	Max %Change
2021SP	14.37	14.42	0.05	0.3%
2028SP	14.41	14.46	0.05	0.3%

Table 4-2: 2021SP Short Circuit Comparison Results[4]

Voltage (kV)	Max. Current (EGF & SGF) (kA)	Max kA Change	Max %Change
69	30.9	0.01	0.0%
115	25.0	0.00	0.0%
138	33.7	0.04	0.2%
230	21.0	0.00	0.0%
345	33.4	0.05	0.3%
Max	**33.7**	**0.05**	**0.3%**

[4] For buses not on the generation interconnection line

Table 4-3: 2028SP Short Circuit Comparison Results[5]

Voltage (kV)	Max. Current (EGF & SGF) (kA)	Max kA Change	Max %Change
69	31.0	0.01	0.0%
115	27.6	0.00	0.0%
138	33.9	0.04	0.2%
230	20.8	0.00	0.0%
345	33.4	0.05	0.3%
Max	**33.9**	**0.05**	**0.3%**

[5] For buses not on the generation interconnection line

5.0 Dynamic Stability Analysis

Aneden performed a dynamic stability analysis to identify the impact of the SGF project. The analysis was performed according to SPP's Disturbance Performance Requirements shown in Appendix C. The project 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.

5.1 Methodology and Criteria

The dynamic stability analysis was performed using models developed with the requested 12 x SMA SC4000-UP 3.76 MW (SMASC167) SGF generating facility configuration included in the cases. The requested project configuration included the use of a PPC (SMAPPC133) to limit the power injection as required. This stability analysis was performed using PTI's PSS/E version 33.10 software.

Two stability model scenarios were developed using the models from DISIS-2017-001 for Group 8. The first scenario (Scenario 1) was comprised of the SGF online and dispatched to maximum capacity (SGF = 42 MW) while the EGF generator was offline and disconnected. The second scenario (Scenario 2) was comprised of the SGF online and dispatched to maximum capacity (SGF = 42 MW) while the EGF generator dispatch was reduced by the amount of Surplus Interconnection Service (EGF = 92 MW). The study scenarios are shown in Table 5-1.

Table 5-1: Study Scenarios

Scenario	GEN-2016-153 EGF (MW)	GEN-2021-SR8 SGF (MW)	EGF + SGF (MW)
1	0	42	42
2	92	42	134

Aneden reviewed the GIRs that shared the same POI, Viola 345 kV, and updated as applicable based on SPP's confirmation of the latest project configurations. As a result, Aneden updated the GEN-2010-005 configuration in the base models.

The following system adjustment was made to address existing base case issues that are not attributed to the Surplus Interconnection Request:

1. The Zsource of FR3WTG1 (578533) was changed to 0.0063+0.1669j
2. The Zsource of several generators using the VWCOR6 or VWCOR8 stability models (521143, 523170, 523171, 532904, 533141, 999125, 999126) was changed to 0.005+0.1991j
3. The Zsource of several generators using the VWCOR4 stability model (531601, 532718, 532720, 539103, 539105) was changed to 0.0046+0.1807j
4. The Zsource of several generators using the VWCOR4 stability model (579441, 640418) was changed to 0.0066+0.2526j
5. The REGCAU1 model CON(J+11) Iqrmax and CON(J+12) Iqrmin were changed from 999 and -999 to 2 and -2 respectively for generators GRNTWDG (515660, 515661) and KAYWNDG (515651, 515652)
6. Reduced the capacitor bank from 40.5 MVAR to 20.25 MVAR at the SLATEGEN1 34.5 kV bus (533139)

7. The instantaneous frequency trip relay was disabled for GEN-2017-018 (588637)
8. The Vschedule of the FRWTG units (533123, 533124, 533125, 533126) was changed from 1.02 to 1.03 and adjusted to regulate the Viola 345 kV voltage instead of their terminal voltage
9. The Qgen of FR3WTG1 and GEN-2016-153 (EGF) was set to 25 MVAR (assuming a 0.98 power factor for Vestas turbines)

The modified dynamics model data for the SGF 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 the EGF and SGF and other equally and prior queued projects in Group 8. In addition, voltages of five (5) buses away from the POI of the SGF 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), 540 (GMO), and 541 (KCPL) were monitored. In addition, the voltages of all 100 kV and above buses within the study area were monitored.

5.2 Fault Definitions

Aneden simulated the faults previously simulated for the EGF (GEN-2016-153) and developed additional fault events as required. The new set of faults were simulated using the modified study models from both scenarios. 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 5-2 below. These contingencies were applied to the modified 2019 Winter Peak, 2021 Summer Peak, 2021 Light Load, and the 2028 Summer Peak models.

Table 5-2: Fault Definitions

Fault ID	Planning Event	Fault Descriptions
FLT21-3PH	P1	3 phase fault on the WOLFCRK7 (532797) to BENTON 7 (532791) 345 kV line circuit 1, near WOLFCRK7. a. Apply fault at the WOLFCRK7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT22-3PH	P1	3 phase fault on the BENTON 7 (532791) to ROSEHILL7 (532794) 345 kV line circuit 1, near BENTON 7. a. Apply fault at the BENTON 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT34-3PH	P1	3 phase fault on the BENTON 7 (532791) to WICHITA7 (532796) 345 kV line circuit 1, near BENTON 7. a. Apply fault at the BENTON 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT82-3PH	P1	3 phase fault on the BUFFALO7 (532782) to WICHITA7 (532796) 345 kV line circuit 1, near BUFFALO7. a. Apply fault at the BUFFALO7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT83-3PH	P1	3 phase fault on the RENO 7 (532771) to WICHITA7 (532796) 345 kV line circuit 1, near RENO 7. a. Apply fault at the RENO 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT84-3PH	P1	3 phase fault on the WICHITA7 (532796) to VIOLA 7 (532798) 345 kV line circuit 1, near WICHITA7. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT88-3PH	P1	3 phase fault on the WICHITA7 (532796) to G14-001-TAP (562476) 345 kV line circuit 1, near WICHITA7. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT89-3PH	P1	3 phase fault on the RENFROW7 (515543) to VIOLA 7 (532798) 345 kV line circuit 1, near RENFROW7. a. Apply fault at the RENFROW7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT91-3PH	P1	3 phase fault on the THISTLE7 (539801) to BUFFALO7 (532782) 345 kV line circuit 1, near THISTLE7. a. Apply fault at the THISTLE7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT149-3PH	P1	3 phase fault on the RENFROW2 345 kV (515543) / 138 kV (515544)/ 13.8 kV (515545) transformer CKT 1, near RENFROW7 345kV. a. Apply fault at the RENFROW7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT150-3PH	P1	3 phase fault on the HUNTERS7 (515476) to RENFROW7 (515543) 345 kV line circuit 1, near HUNTERS7. a. Apply fault at the HUNTERS7 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 5-2 continued

Fault ID	Planning Event	Fault Descriptions
FLT179-3PH	P1	3 phase fault on the WOLFCRK7 (532797) to ROSEHILL7 (532794) 345 kV line circuit 1, near WOLFCRK7. a. Apply fault at the WOLFCRK7 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.
FLT34-PO1	P6	**PRIOR OUTAGE of WICHITA7 (532796) to G14-001-TAP (562476) 345 kV line circuit 1;** 3 phase fault on the BENTON 7 (532791) to WICHITA7 (532796) 345 kV line circuit 1, near BENTON 7. a. Apply fault at the BENTON 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT82-PO1	P6	**PRIOR OUTAGE of WICHITA7 (532796) to G14-001-TAP (562476) 345 kV line circuit 1;** 3 phase fault on the BUFFALO7 (532782) to WICHITA7 (532796) 345 kV line circuit 1, near BUFFALO7. a. Apply fault at the BUFFALO7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT84-PO1	P6	**PRIOR OUTAGE of WICHITA7 (532796) to G14-001-TAP (562476) 345 kV line circuit 1;** 3 phase fault on the WICHITA7 (532796) to VIOLA 7 (532798) 345 kV line circuit 1, near WICHITA7. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT89-PO1	P6	**PRIOR OUTAGE of WICHITA7 (532796) to G14-001-TAP (562476) 345 kV line circuit 1;** 3 phase fault on the RENFROW7 (515543) to VIOLA 7 (532798) 345 kV line circuit 1, near RENFROW7. a. Apply fault at the RENFROW7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT179-PO2	P6	**PRIOR OUTAGE of BENTON 7 (532791) to ROSEHILL7 (532794) 345 kV line circuit 1;** 3 phase fault on the WOLFCRK7 (532797) to ROSEHILL7 (532794) 345 kV line circuit 1, near WOLFCRK7. a. Apply fault at the WOLFCRK7 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.
FLT84-PO3	P6	**PRIOR OUTAGE of WICHITA7 (532796) to BUFFALO7 (532782) 345 kV line circuit 1;** 3 phase fault on the WICHITA7 (532796) to VIOLA 7 (532798) 345 kV line circuit 1, near WICHITA7. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT89-PO3	P6	**PRIOR OUTAGE of WICHITA7 (532796) to BUFFALO7 (532782) 345 kV line circuit 1;** 3 phase fault on the RENFROW7 (515543) to VIOLA 7 (532798) 345 kV line circuit 1, near RENFROW7. a. Apply fault at the RENFROW7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT89-PO4	P6	**PRIOR OUTAGE of WICHITA7 (532796) to VIOLA 7 (532798) 345 kV line circuit 1;** 3 phase fault on the RENFROW7 (515543) to VIOLA 7 (532798) 345 kV line circuit 1, near RENFROW7. a. Apply fault at the RENFROW7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.

Table 5-2 continued

Fault ID	Planning Event	Fault Descriptions
FLT82-PO5	P6	**PRIOR OUTAGE of WICHITA7 (532796) to BENTON 7 (532791) 345 kV line circuit 1;** 3 phase fault on the BUFFALO7 (532782) to WICHITA7 (532796) 345 kV line circuit 1, near BUFFALO7. a. Apply fault at the BUFFALO7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT84-PO5	P6	**PRIOR OUTAGE of WICHITA7 (532796) to BENTON 7 (532791) 345 kV line circuit 1;** 3 phase fault on the WICHITA7 (532796) to VIOLA 7 (532798) 345 kV line circuit 1, near WICHITA7. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9001-3PH	P1	3 phase fault on the VIOLA 7 (532798) to GEN-2017-086 (589240) 345 kV line circuit 1, near VIOLA 7. a. Apply fault at the VIOLA 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G17-086-GEN1 (589243).** **Trip generator G17-086-GEN2 (589245).** 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 VIOLA 7 (532798) to RENFROW7 (515543) 345 kV line circuit 1, near VIOLA 7. a. Apply fault at the VIOLA 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9003-3PH	P1	3 phase fault on the VIOLA TX-1 345 kV (532798) / 138 kV (533075)/ 13.8 kV (532832) transformer CKT 1, near VIOLA 7 345kV. a. Apply fault at the VIOLA 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9004-3PH	P1	3 phase fault on the VIOLA 7 (532798) to WICHITA7 (532796) 345 kV line circuit 1, near VIOLA 7. a. Apply fault at the VIOLA 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9005-3PH	P1	3 phase fault on the RENFROW7 (515543) to HUNTERS7 (515476) 345 kV line circuit 1, near RENFROW7. a. Apply fault at the RENFROW7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9006-3PH	P1	3 phase fault on the RENFROW7 (515543) to GRNTWD 7 (515646) 345 kV line circuit 1, near RENFROW7. a. Apply fault at the RENFROW7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator GRNTWDG1 (515660).** **Trip generator GRNTWDG2 (515661).** 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.
FLT9007-3PH	P1	3 phase fault on the HUNTERS7 (515476) to WOODRNG7 (514715) 345 kV line circuit 1, near HUNTERS7. a. Apply fault at the HUNTERS7 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 5-2 continued

Fault ID	Planning Event	Fault Descriptions
FLT9008-3PH	P1	3 phase fault on the HUNTERS7 (515476) to CHSHLMV7 (515477) 345 kV line circuit 1, near HUNTERS7. a. Apply fault at the HUNTERS7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator CHSVWEG1 (515926).** **Trip generator CHSHMV12-WTG (599089).** **Trip generator CHSVWWG1 (515927).** **Trip generator CHSHMV22-WTG (599090).** 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 WICHITA7 (532796) to BENTON 7 (532791) 345 kV line circuit 1, near WICHITA7. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9010-3PH	P1	3 phase fault on the WICHITA7 (532796) to RENO 7 (532771) 345 kV line circuit 1, near WICHITA7. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9011-3PH	P1	3 phase fault on the WICHITA7 (532796) to GEN-2017-068 (589060) 345 kV line circuit 1, near WICHITA7. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G17-068-GEN1 (589063).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9012-3PH	P1	3 phase fault on the WICH TX-11 345 kV (532796) / 138 kV (533040)/ 13.8 kV (532829) transformer CKT 1, near WICHITA7 345kV. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9013-3PH	P1	3 phase fault on the WICHITA7 (532796) to BUFFALO7 (532782) 345 kV line circuit 1, near WICHITA7. a. Apply fault at the WICHITA7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9014-3PH	P1	3 phase fault on the BENT TX-1 345 kV (532791) / 138 kV (532986)/ 13.8 kV (532821) transformer CKT 1, near BENTON 7 345kV. a. Apply fault at the BENTON 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9015-3PH	P1	3 phase fault on the BENTON 7 (532791) to WOLFCRK7 (532797) 345 kV line circuit 1, near BENTON 7. a. Apply fault at the BENTON 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9016-3PH	P1	3 phase fault on the BENTON 7 (532791) to GEN-2016-162 (588320) 345 kV line circuit 1, near BENTON 7. a. Apply fault at the BENTON 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G16-163-GEN1 (588333).** **Trip generator G16-162-GEN1 (588323).** 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 RENO TX-1 345 kV (532771) / 115 kV (533416)/ 13.8 kV (532807) transformer CKT 1, near RENO 7 345kV. a. Apply fault at the RENO 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.

Table 5-2 continued

Fault ID	Planning Event	Fault Descriptions
FLT9018-3PH	P1	3 phase fault on the RENO 7 (532771) to G16-111-TAP (587884) 345 kV line circuit 1, near RENO 7. a. Apply fault at the RENO 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9019-3PH	P1	3 phase fault on the G14-001-TAP (562476) to EMPEC 7 (532768) 345 kV line circuit 1, near G14-001-TAP. a. Apply fault at the G14-001-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9020-3PH	P1	3 phase fault on the G14-001-TAP (562476) to GEN-2014-001 (583850) 345 kV line circuit 1, near G14-001-TAP. a. Apply fault at the G14-001-TAP 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G14-001-GEN1 (583853).** **Trip generator G14-001-GEN2 (583856).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9021-3PH	P1	3 phase fault on the BUFFALO7 (532782) to THISTLE7 (539801) 345 kV line circuit 1, near BUFFALO7. a. Apply fault at the BUFFALO7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9022-3PH	P1	3 phase fault on the BUFFALO7 (532782) to GEN-2016-073 (587500) 345 kV line circuit 1, near BUFFALO7. a. Apply fault at the BUFFALO7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator G16-073-GEN1 (587503).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9023-3PH	P1	3 phase fault on the BUFFALO7 (532782) to KINGMAN7 (532783) 345 kV line circuit 1, near BUFFALO7. a. Apply fault at the BUFFALO7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. **Trip generator K2 WF 1 (534022).** **Trip generator K1 WF 1 (534021).** **Trip generator K2 WF 2 (584677).** **Trip generator G15-090-SW23 (585253).** **Trip generator G15-090-GW23 (585256).** **Trip generator N1 WF 1 (534020).** c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9002-PO4	P6	**PRIOR OUTAGE of WICHITA7 (532796) to VIOLA 7 (532798) 345 kV line circuit 1;** 3 phase fault on the VIOLA 7 (532798) to RENFROW7 (515543) 345 kV line circuit 1, near VIOLA 7. a. Apply fault at the VIOLA 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9003-PO4	P6	**PRIOR OUTAGE of WICHITA7 (532796) to VIOLA 7 (532798) 345 kV line circuit 1;** 3 phase fault on the VIOLA TX-1 345 kV (532798) / 138 kV (533075)/ 13.8 kV (532832) transformer CKT 1, near VIOLA 7 345kV. a. Apply fault at the VIOLA 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9003-PO6	P6	**PRIOR OUTAGE of VIOLA 7 (532798) to RENFROW7 (515543) 345 kV line circuit 1;** 3 phase fault on the VIOLA TX-1 345 kV (532798) / 138 kV (533075)/ 13.8 kV (532832) transformer CKT 1, near VIOLA 7 345kV. a. Apply fault at the VIOLA 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.

Table 5-2 continued

Fault ID	Planning Event	Fault Descriptions
FLT9004-PO6	P6	**PRIOR OUTAGE of VIOLA 7 (532798) to RENFROW7 (515543) 345 kV line circuit 1;** 3 phase fault on the VIOLA 7 (532798) to WICHITA7 (532796) 345 kV line circuit 1, near VIOLA 7. a. Apply fault at the VIOLA 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9002-PO7	P6	**PRIOR OUTAGE of VIOLA TX-1 345 kV (532798) / 138 kV (533075)/ 13.8 kV (532832) transformer CKT 2;** 3 phase fault on the VIOLA 7 (532798) to RENFROW7 (515543) 345 kV line circuit 1, near VIOLA 7. a. Apply fault at the VIOLA 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT9003-PO7	P6	**PRIOR OUTAGE of VIOLA TX-1 345 kV (532798) / 138 kV (533075)/ 13.8 kV (532832) transformer CKT 2;** 3 phase fault on the VIOLA TX-1 345 kV (532798) / 138 kV (533075)/ 13.8 kV (532832) transformer CKT 1, near VIOLA 7 345kV. a. Apply fault at the VIOLA 7 345 kV bus. b. Clear fault after 6 cycles and trip the faulted transformer.
FLT9004-PO7	P6	**PRIOR OUTAGE of VIOLA TX-1 345 kV (532798) / 138 kV (533075)/ 13.8 kV (532832) transformer CKT 2;** 3 phase fault on the VIOLA 7 (532798) to WICHITA7 (532796) 345 kV line circuit 1, near VIOLA 7. a. Apply fault at the VIOLA 7 345 kV bus. b. Clear fault after 6 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 6 cycles, then trip the line in (b) and remove fault.
FLT1001-SB	P4	**Stuck Breaker on at WICHITA7 (532796) at 345kV bus** a. Apply single-phase fault at WICHITA7 (532796) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the WICHITA7 (532796) to G14-001-TAP (562476) 345 kV line circuit 1. d. Trip the WICH TX-11 345 kV (532796) / 138 kV (533040)/ 13.8 kV (532829) transformer CKT 1.
FLT1002-SB	P4	**Stuck Breaker on at WICHITA7 (532796) at 345kV bus** a. Apply single-phase fault at WICHITA7 (532796) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the WICHITA7 (532796) to RENO 7 (532771) 345 kV line circuit 1. d. Trip the WICHITA7 (532796) to BENTON 7 (532791) 345 kV line circuit 1.
FLT1003-SB	P4	**Stuck Breaker on at WICHITA7 (532796) at 345kV bus** a. Apply single-phase fault at WICHITA7 (532796) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the WICHITA7 (532796) to BUFFALO7 (532782) 345 kV line circuit 1. d. Trip the WICH TX-12 345 kV (532796) / 138 kV (533040)/ 13.8 kV (532830) transformer CKT 1.
FLT1004-SB	P4	**Stuck Breaker on at WICHITA7 (532796) at 345kV bus** a. Apply single-phase fault at WICHITA7 (532796) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the WICHITA7 (532796) to BUFFALO7 (532782) 345 kV line circuit 2. d. Trip the WICHITA7 (532796) to VIOLA 7 (532798) 345 kV line circuit 1.
FLT1005-SB	P4	**Stuck Breaker on at RENFROW7 (515543) at 345kV bus** a. Apply single-phase fault at RENFROW7 (515543) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the RENFROW7 (515543) to VIOLA 7 (532798) 345 kV line circuit 1. d. Trip the RENFROW2 345 kV (515543) / 138 kV (515544)/ 13.8 kV (515545) transformer CKT 1.
FLT1006-SB	P4	**Stuck Breaker on at RENFROW7 (515543) at 345kV bus** a. Apply single-phase fault at RENFROW7 (515543) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the RENFROW7 (515543) to VIOLA 7 (532798) 345 kV line circuit 1. d. Trip the RENFROW7 (515543) to GRNTWD 7 (515646) 345 kV line circuit 1. **Trip generator GRNTWDG1 (515660).** **Trip generator GRNTWDG2 (515661).**

Table 5-2 continued

Fault ID	Planning Event	Fault Descriptions
FLT1007-SB	P4	**Stuck Breaker on at RENFROW7 (515543) at 345kV bus** a. Apply single-phase fault at RENFROW7 (515543) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the RENFROW7 (515543) to HUNTERS7 (515476) 345 kV line circuit 1. d. Trip the RENFROW7 (515543) to GRNTWD 7 (515646) 345 kV line circuit 1. **Trip generator GRNTWDG1 (515660).** **Trip generator GRNTWDG2 (515661).**
FLT1008-SB	P4	**Stuck Breaker on at RENFROW7 (515543) at 345kV bus** a. Apply single-phase fault at RENFROW7 (515543) on the 345kV bus. b. After 16 cycles, trip the following elements c. Trip the RENFROW7 (515543) to HUNTERS7 (515476) 345 kV line circuit 1. d. Trip the RENFROW2 345 kV (515543) / 138 kV (515544)/ 13.8 kV (515545) transformer CKT 1.

5.3 Scenario 1 Results

Table 5-3 shows the results of the fault events simulated for each of the four modified cases in Scenario 1. The associated stability plots are provided in Appendix D.

Table 5-3: Scenario 1 (EGF = 0 MW, SGF = 42 MW)

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
FLT21-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT22-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT34-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT82-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT83-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT84-3PH	Pass	Pass	Stable(1)	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT88-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT89-3PH	Pass	Pass	Stable(1)	Pass	Pass	Stable(1) (2)	Pass	Pass	Stable	Pass	Pass	Stable(1)
FLT91-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT149-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT150-3PH	Pass	Pass	Stable(1)	Pass	Pass	Stable (2)	Pass	Pass	Stable(1)	Pass	Pass	Stable(1)
FLT179-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable(1)	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable(1)	Pass	Pass	Stable (2)	Pass	Pass	Stable(1)	Pass	Pass	Stable(1)
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable(1)	Pass	Pass	Stable (2)	Pass	Pass	Stable(1)	Pass	Pass	Stable(1)
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable

Table 5-3 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
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable(1)	Pass	Pass	Stable(1) (2)	Pass	Pass	Stable(1)	Pass	Pass	Stable(1)
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable(1)	Pass	Pass	Stable(1) (2)	Pass	Pass	Stable(1)	Pass	Pass	Stable(1)
FLT34-PO1	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT82-PO1	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT84-PO1	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT89-PO1	Pass	Pass	Stable(1)	Pass	Pass	Stable(1) (2)	Pass	Pass	Stable(1)	Pass	Pass	Stable(1)
FLT179-PO2	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT84-PO3	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT89-PO3	Pass	Pass	Stable(1)	Pass	Pass	Stable(1) (2)	Pass	Pass	Stable(1)	Pass	Pass	Stable(1)
FLT89-PO4	Pass	Pass	Stable(1)	Pass	Pass	Stable(1) (2)	Pass	Pass	Stable(1)	Pass	Pass	Stable(1)

Table 5-3 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
FLT9002-PO4	Pass	Pass	Stable(1)	Pass	Pass	Stable (2)	Pass	Pass	Stable(1)	Pass	Pass	Stable(1)
FLT9003-PO4	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT82-PO5	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT84-PO5	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO6	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO6	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO7	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO7	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO7	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable

(1) GRNTWDG units (515660, 515661) had high frequency oscillations in cases with and without GEN-2021-SR8 included

(2) REDBUD units (514899, 514900, 514905, 514910, 514940, 514942) had EFD oscillations in the 21LL case with and without GEN-2021-SR8 included

The existing DISIS base case without any fault events had a low voltage steady state violation on bus 588043 (G16133_765MP 765 kV). This steady state violation was ignored as it was not attributed to the SGF.

During the multiple faults across all four cases the GRNTWDG units (515660 & 515661) had high frequency oscillations. This was observed in both the DISIS and Scenario 1 cases, so it was not attributed to the SGF. Figure 5-1 shows the GRNTWDG oscillation during FLT89-3PH in the 19WP Scenario 1 case. This problem was also present in the existing DISIS-2017-001 19WP case as shown in Figure 5-2.

Figure 5-1: FLT89-3PH GRNTWDG (515660 & 515661) Oscillations (19WP Scenario 1 Case)

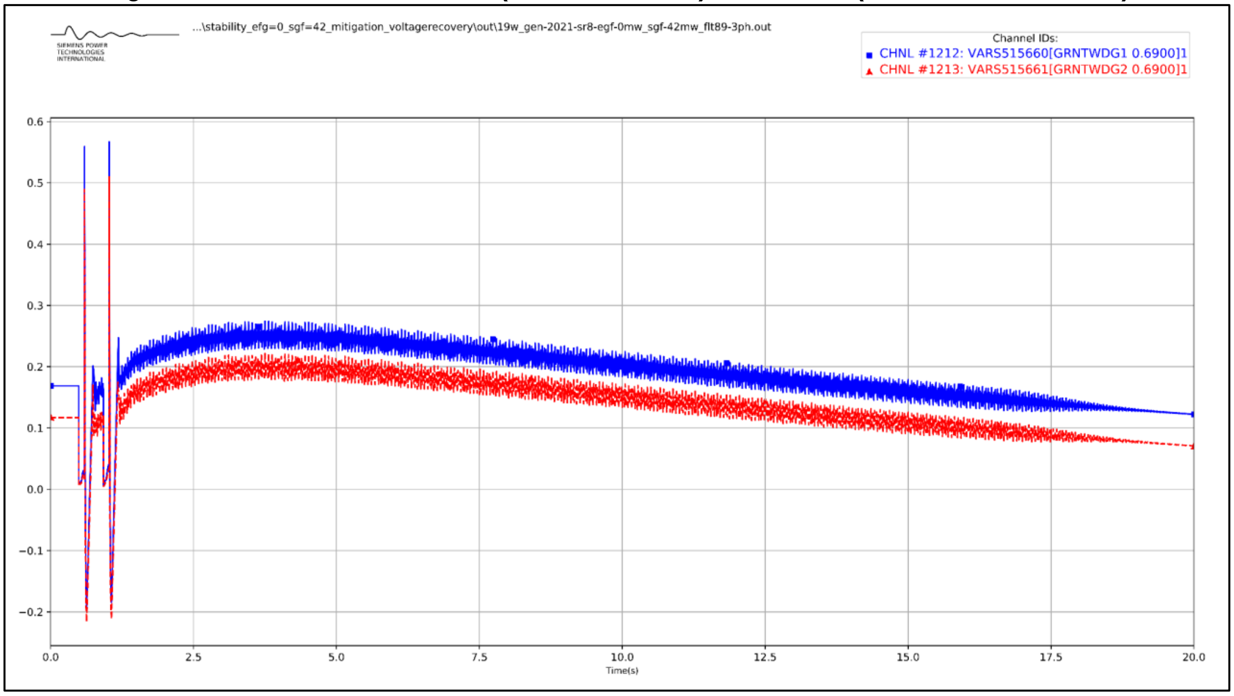
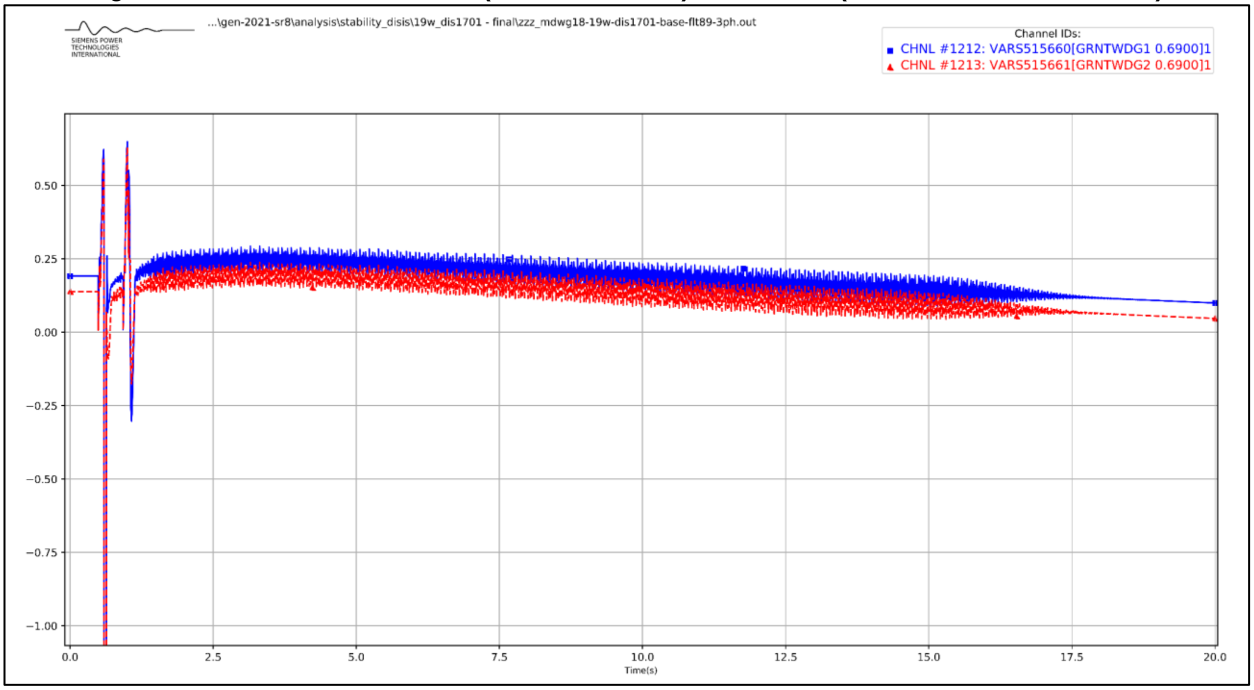


Figure 5-2: FLT89-3PH GRNTWDG (515660 & 515661) Oscillations (19WP DISIS-2017-001 Case)



During every fault studied in the 21LL case the REDBUD units (514899, 514900, 514905, 514910, 514940, 514942) showed EFD oscillations. This was observed in both the DISIS and Scenario 1 cases, so it was not attributed to the SGF. Figure 5-3 shows the REDBUD EFD oscillation during FLT21-3PH in the 21LL Scenario 1 case. This problem was also present in the existing DISIS-2017-001 21LL case as shown in Figure 5-4.

Figure 5-3: FLT21-3PH REDBUD Units EFD Oscillations (21LL Scenario 1 Case)

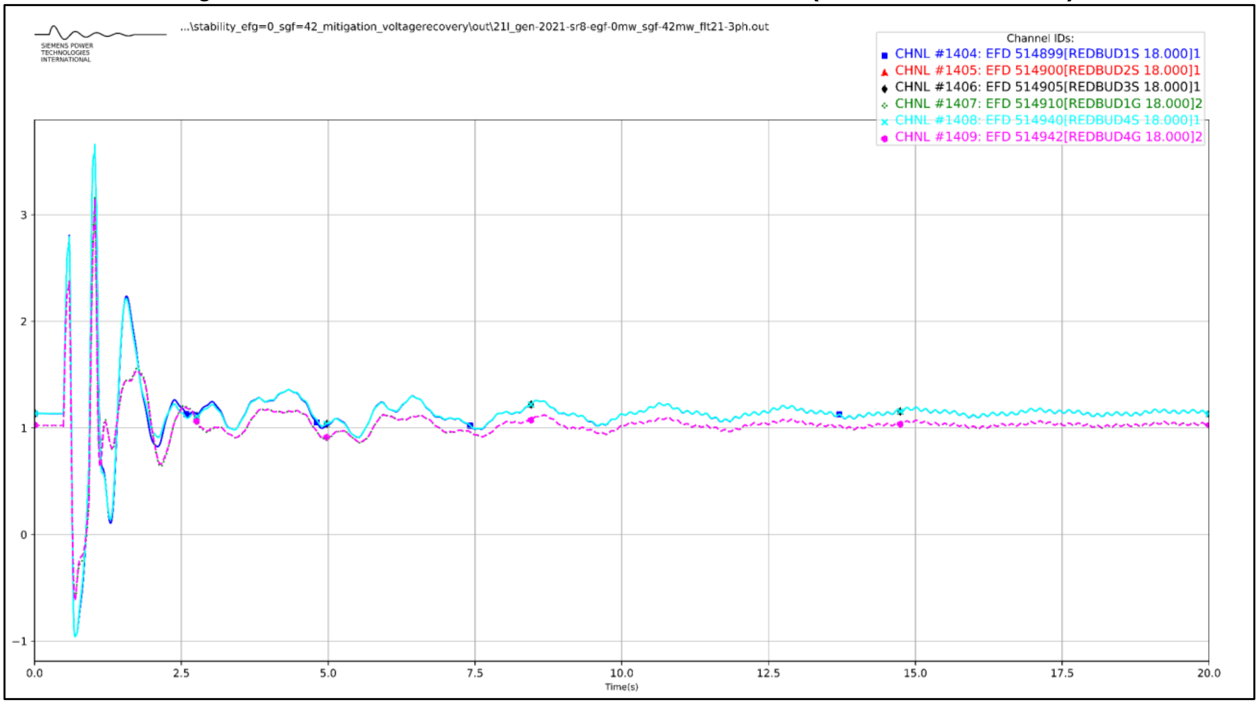
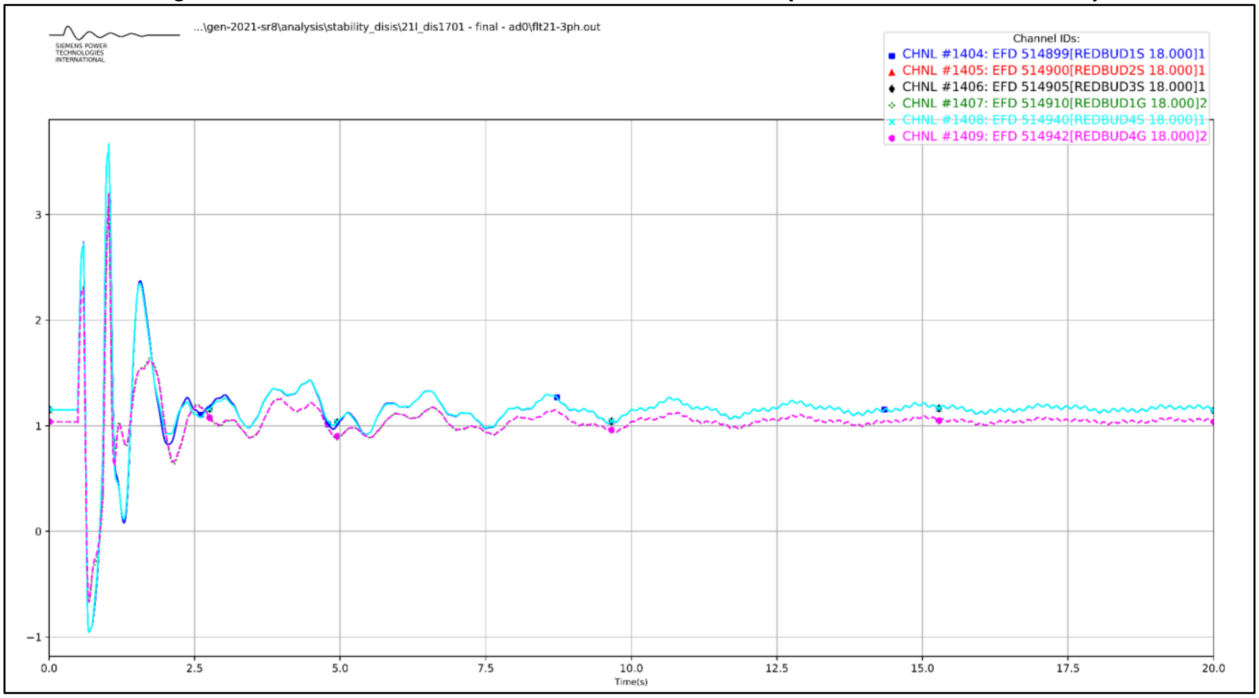


Figure 5-4: FLT21-3PH REDBUD Units EFD Oscillations (21LL DISIS-2017-001 Case)



There were no damping or voltage recovery violations attributed to the GEN-2021-SR8 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.

5.4 Scenario 2 Results

Table 5-4 shows the results of the fault events simulated for each of the four modified cases in Scenario 2. The associated stability plots are provided in Appendix D.

Table 5-4: Scenario 2 (EGF = 92 MW, SGF = 42 MW)

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
FLT21-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT22-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT34-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT82-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT83-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT84-3PH	Pass	Pass	Stable(1)	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT88-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT89-3PH	Pass	Pass	Stable(1)	Pass	Pass	Stable(1) (2)	Pass	Pass	Stable	Pass	Pass	Stable(1)
FLT91-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT149-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT150-3PH	Pass	Pass	Stable(1)	Pass	Pass	Stable (2)	Pass	Pass	Stable(1)	Pass	Pass	Stable(1)
FLT179-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9001-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-3PH	Pass	Pass	Stable(1)	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9005-3PH	Pass	Pass	Stable(1)	Pass	Pass	Stable (2)	Pass	Pass	Stable(1)	Pass	Pass	Stable(1)
FLT9006-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9007-3PH	Pass	Pass	Stable(1)	Pass	Pass	Stable (2)	Pass	Pass	Stable(1)	Pass	Pass	Stable(1)
FLT9008-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9009-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9010-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9011-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9012-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9013-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9014-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9015-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9016-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable

Table 5-4 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
FLT9017-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9018-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9019-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9020-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9021-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9022-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9023-3PH	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT1001-SB	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT1002-SB	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT1003-SB	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT1004-SB	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT1005-SB	Pass	Pass	Stable(1)	Pass	Pass	Stable(1) (2)	Pass	Pass	Stable(1)	Pass	Pass	Stable(1)
FLT1006-SB	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT1007-SB	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT1008-SB	Pass	Pass	Stable(1)	Pass	Pass	Stable(1) (2)	Pass	Pass	Stable(1)	Pass	Pass	Stable(1)
FLT34-PO1	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT82-PO1	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT84-PO1	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT89-PO1	Pass	Pass	Stable(1)	Pass	Pass	Stable(1) (2)	Pass	Pass	Stable(1)	Pass	Pass	Stable(1)
FLT179-PO2	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT84-PO3	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT89-PO3	Pass	Pass	Stable(1)	Pass	Pass	Stable(1) (2)	Pass	Pass	Stable(1)	Pass	Pass	Stable(1)
FLT89-PO4	Pass	Pass	Stable(1)	Pass	Pass	Stable(1) (2)	Pass	Pass	Stable(1)	Pass	Pass	Stable(1)
FLT9002-PO4	Pass	Pass	Stable(1)	Pass	Pass	Stable (2)	Pass	Pass	Stable(1)	Pass	Pass	Stable(1)
FLT9003-PO4	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT82-PO5	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT84-PO5	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO6	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9004-PO6	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9002-PO7	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable
FLT9003-PO7	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable

Table 5-4 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
FLT9004-PO7	Pass	Pass	Stable	Pass	Pass	Stable (2)	Pass	Pass	Stable	Pass	Pass	Stable

(1) GRNTWDG units (515660, 515661) had high frequency oscillations in cases with and without GEN-2021-SR8 included
(2) REDBUD units (514899, 514900, 514905, 514910, 514940, 514942) had EFD oscillations in the 21LL case with and without GEN-2021-SR8 included

The Scenario 2 results showed the same base case issues described in Section 5.3 for Scenario 1. There were no new violations seen in Scenario 2.

There were no damping or voltage recovery violations attributed to the GEN-2021-SR8 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.

6.0 Necessary Interconnection Facilities and Network Upgrades

This study identified the impact of the Surplus Interconnection Service of the transmission system reliability and any additional Interconnection Facilities or Network Upgrades necessary. The Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades.

6.1 Interconnection Facilities

This study did not identify any additional Interconnection Facilities required by the addition of the SGF.

6.2 Network Upgrades

This study did not identify any Network Upgrades required by the addition of the SGF.

7.0 Surplus Interconnection Service Determination and Requirements

In accordance with Attachment V of SPP's Open Access Transmission Tariff, SPP shall evaluate the request for Surplus Interconnection Service and inform the Interconnection Customer in writing of whether the Surplus Interconnection Service can be utilized without negatively impacting the reliability of the Transmission System and without any additional Network Upgrades necessary.

7.1 Surplus Service Determination

SPP determined the request for Surplus Interconnection Service does not negatively impact the reliability of the Transmission System and no required Network Upgrades or Interconnection Facilities were identified by this Surplus Interconnection Service Impact Study performed by Aneden. Aneden evaluated the impact of the requested Surplus Interconnection Service on the prior study results and determined that the requested Surplus Interconnection Service resulted in similar dynamic stability and short circuit analyses and that the prior study power flow results are not negatively impacted.

SPP has determined that GEN-2021-SR8 may utilize the requested 42 MW of Surplus Interconnection Service provided by GEN-2016-153.

7.2 Surplus Service Requirements

The amount of Surplus Interconnection Service available to be used is limited by the amount of Interconnection Service granted to the existing interconnection customer at the same POI. The combined generation from both the SGF and the EGF may not exceed 134 MW at the POI, which is the total Interconnection Service amount currently granted to the EGF.

The customer must install monitoring and control equipment as needed to ensure that the SGF does not exceed the granted surplus amount and to ensure that combination of the SGF and EGF power injected at the POI does not exceed the Interconnection Service amount listed in the EGF's GIA. The monitoring and control scheme will need to be reviewed by SPP and the TO and documented in Appendix C of the GIA.

8.0 Conclusions

The GEN-2021-SR8 Interconnection Customer has requested a Surplus Interconnection Service Impact Study (Study) for GEN-2021-SR8 (SGF) to utilize the Surplus Interconnection Service provided by GEN-2016-153 (EGF) at its existing the point of interconnection (POI), the Viola 345 kV substation.

The scope of this study included a charging current compensation analysis, short circuit analysis, and dynamic stability analysis. Since the EGF and SGF are both non-synchronous fuel types, SPP determined that power flow analysis should not be performed as the EGF was studied previously under the required reliability conditions.

Aneden reviewed the GIRs that shared the same POI, Viola 345 kV, and updated as applicable based on SPP's confirmation of the latest project configurations. As a result, Aneden updated the GEN-2010-005 configuration 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 SGF project needed an approximately 0.4 MVAr shunt reactor at the project substation, to reduce the POI MVAr to zero when the GEN-2010-005 Phase II, GEN-2007-025 & GEN-2010-005 Phase I, and EGF projects have shunt reactors compensating their charging effects. This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during reduced generation conditions. The information gathered from the charging current compensation analysis is provided as information to the Interconnection Customer and Transmission Owner (TO) and/or Transmission Operator. The applicable reactive power requirements will be further reviewed by the Transmission Owner and/or Transmission Operator.

The results from the short circuit analysis compared the existing DISIS case (EGF online, SGF not included) 2021SP and 2028SP models to the SGF study case (EGF and SGF online) 2021SP and 2028SP models. The maximum contribution to three-phase fault currents in the immediate transmission systems due to the addition of the SGF was not greater than 0.05 kA[6]. All three-phase fault current levels within 5 buses of the POI with the EGF and SGF generators online were below 34 kA for the 2021SP models 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 with two dispatch scenarios. In the first scenario, the SGF was online at 42 MW while the EGF was offline and disconnected. The second scenario included a combination of the SGF dispatched to maximum at 42 MW and the EGF picking up the remaining 92 MW for a total combination of 134 MW. Up to 60 events were simulated, which included three-phase faults, three-phase faults on prior outage cases, and single-line-to-ground faults with stuck breakers faults.

[6] For buses not on the generation interconnection line

The results of the dynamic stability analysis showed that there were numerous existing base case issues that were mitigated prior to studying the SGF. These case adjustments are listed in Section 5.1. In addition, there were two types of existing stability oscillations. First, multiple faults across all four cases caused the GRNTWDG units (515660 & 515661) to have high frequency oscillations. Second, EFD oscillations were found for every fault studied in the 21LL case from the REDBUD units (514899, 514900, 514905, 514910, 514940, 514942). These issues were observed in the DISIS, Scenario 1, and Scenario 2 cases so they were not attributed to the SGF.

There were no damping or voltage recovery violations attributed to the GEN-2021-SR8 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 results of the study showed that the Surplus Interconnection Service Request by GEN-2021-SR8 did not negatively impact the reliability of the Transmission System. There were no additional Interconnection Facilities or Network Upgrades identified by the analyses.

SPP has determined that GEN-2021-SR8 may utilize the requested 42 MW of Surplus Interconnection Service provided by the EGF. The combined generation from both the SGF and the EGF may not exceed 134 MW at the POI which is the total Interconnection Service amount currently granted to the EGF.

The customer must install monitoring and control equipment as needed to ensure that the SGF does not exceed the granted surplus amount and to ensure that combination of the SGF and EGF power injected at the POI does not exceed the Interconnection Service amount listed in the EGF's GIA. The monitoring and control scheme will need to be reviewed by SPP and the TO and documented in Appendix C of the GIA.

In accordance with FERC Order No. 827, both the SGF and EGF 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.