Enel Green Power
GEN-2017-027 Interim Availability Interconnection System Impact Study
Final

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LEGAL NOTICE

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EXECUTIVE SUMMARY

Hitachi ABB Power Grids Power Consulting was retained by Enel Green Power (Enel) to perform an Interim Availability System Impact Study (the Study or IASIS) for interconnection request GEN-2017-027 in SPP's Generator Interconnection Queue. The interconnection request is in regional Group 14. GEN-2017-027 is a proposed wind farm in Carter County, OK with a gross power output of 140 MW. The point of interconnection (POI) of the proposed wind project is the Carter County 138 kV substation that is owned and operated by Oklahoma Gas & Electric (OGE). The Interconnection Customer has requested this amount to be studied for Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). The expected in-service date of the project is approximately December 2021.

SPP provided an approved scope[1] for the IASIS that covered the types of analyses to be performed in the study, models to be used, system to be monitored, study criteria, prior-queued projects and network upgrades to be considered and the types of contingencies to be tested.

This study included power flow, stability, short circuit, and reactive compensation analyses and was performed to determine the amount of requested Interconnection Service (Service) that is available for GEN-2017-027 to interconnect to the Transmission System.

- For the power flow analysis, GEN-2017-027 was modeled using the project data that Enel submitted in 2017, in which GEN-2017-027 was proposed to be comprised of seventy (70) Vestas 2.0 MW wind turbines.
- For the transient stability analysis, short circuit analysis, and reactive compensation analysis, GEN-2017-027 was modeled using the updated project data that Enel submitted in 2021 at Decision Point 2, in which GEN-2017-027 was changed to eleven (11) Vestas V110 2.2 MW turbines, twenty one (21) Vestas V120 2.2 MW, nine (9) Vestas V150 CP 4.0 MW turbines, and eight (8) Vestas V150 CP 4.2 MW turbines. The total interconnection request remains 140 MW (gross).

  Note: The power flow analysis was not repeated using the updated project data. SPP confirmed during the status meeting on May 25, 2021 that there is no need to re-run power flow analysis using the updated project data that the Interconnection Customer submitted at Decision Point 2.

The IASIS assumes that the projects tabulated in Table 1-1 of this report will go into service. If additional generation projects with queue priority equal to or higher than GEN-2017-027 go into commercial operation, this IASIS may need to be restudied to ensure that interconnection service remains for the customer's request.

All the analyses were performed using PSS/E v. 33.10.0 and PSS MUST 12.4.

[1] "Interim Study Scope GEN-2017-027 2020-09-01 - ABB Schedule_JS.docx" – attachment in e-mail from Jennifer Swierczek (SPP) to Matthew Keenan (Enel) dated September 10, 2020.

Power Flow Analysis

Power flow analysis was performed using the DISIS-2016-002 series study models representative of the following seven (7) study years and system load levels: 2017 Winter Peak (17WP), 2018 Spring (18G), 2018 Summer Peak (18SP), 2021 Light (21L), 2021 Summer Peak (21SP), 2021 Winter Peak (21WP), and 2026 Summer Peak (26SP). Results of the ERIS and NRIS analyses indicate that:

- No constraints are identified with GEN-2017-027 TDF > 3% under system intact conditions. There are two P4_2 contingencies that resulted in overloads on 138 kV facilities and GEN-2017-027 has TDF >20% on the overloaded facilities. Since the rated voltage level of the overloaded facilities is less than 300 kV, GEN-2017-027 is not required to mitigate the overloads caused by these two contingencies.
- No voltage violations were identified that are attributable to GEN-2017-027.
- GEN-2017-027 does not exhibit a DF > 3% on any contingent elements that resulted in a non-converged solution.

Transient Stability Analysis

Transient stability analysis was performed using dynamic stability models derived from the 2016 series models of the Model Development Working Group (MDWG) and included the 2017 winter peak (2017WP), 2018 summer peak (2018SP) and 2026 summer peak (2026SP) dynamic cases. GEN-2017-027 was modeled using the project data that Enel submitted in 2021.

Seventy five (75) NERC Category P1, P4 and P6 fault events were simulated for all three cases. The first pass of simulation results showed oscillatory voltage responses under certain P4 and P6 faults at the Carter County and Sunnyside 138 kV substations. Further investigations show that the short circuit strength at the proposed POI (i.e., Carter County 138 kV) is rather low and the control interactions between GEN-2017-027 and the nearby Origin Wind Project[2] adversely impact post-fault transient voltage recovery. These findings were discussed with Enel who then contacted Vestas to assist with the specific stability related concerns. As part of the effort to mitigate the oscillatory voltage responses, Vestas undertook considerable analysis of the projects and the surrounding grid. Vestas' analysis, performed in PSCAD for the Rockhaven and Origin Wind projects, resulted in the need for relevant control parameter changes to be implemented at the projects to improve performance related issues caused by low short circuit strength. The parameter changes at Rockhaven and Origin include updates to the Power Plant Controller (PPC) and wind turbine parameters to ensure stable operation. After the completion of the PSCAD analysis, Vestas updated the PSS/E models for the Rockhaven and Origin wind farms and provided them to Enel for use in this study. In addition, Vestas recommended that the bus voltages at Carter County 138 kV be adjusted to a minimum of 1.03 pu under pre-contingency conditions in order to mitigate stability issues due to low short circuit strength.

[2] The POI of the Origin Wind Farm (rated 150 MW gross) is also Carter County 138 kV.

All proposed fault events were re-simulated for the three cases using the updated models and adjusting the voltages at the Carter County 138 kV bus to around 1.03 pu. Based on the dynamic results, GEN-2017-027 did not adversely impact system stability and remained stable for all faults studied. Additionally, GEN-2017-027 was found to stay connected during the contingencies that were studied and therefore, meets the voltage and frequency ride-through requirements of FERC Order 661-A and NERC PRC-024-2.

Short Circuit Analysis

Short-circuit analysis was performed to determine the impact of GEN-2017-027 on fault currents at the Carter County 138 kV bus and at other buses in the electrical vicinity in the 2026SP stability case. Results show that the maximum increase in fault current is about 10.27%, 0.84 kA at the Carter County 138 kV bus.

Reactive Compensation Analysis

Reactive compensation analysis was conducted using the 2026SP stability case to determine the capacitive charging effects of the project's interconnection line and collector transformer and cables during low/no wind conditions while the project is still connected to the grid and to size the shunt reactor that would reduce the project reactive power contribution to the POI to approximately zero. In this analysis, it was determined that a 6.7 MVAr shunt reactor (approx.) at the 34.5 kV side of project's main substation, reduces the MVAr from the project to the POI bus to zero.

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1 Introduction

Enel Green Power (the Interconnection Customer) has requested an Interim Availability System Impact Study (IASIS) under the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT) for interconnection request GEN-2017-027 into the Oklahoma Gas and Electric Company (OGE) transmission system.

The purpose of this study is to evaluate the impact of interconnecting request GEN-2017-027 with a total of 140 MW (gross) of generation seeking interconnection at the Carter County 138 kV substation in Carter County, OK. The Interconnection Customer has requested this amount to be studied for Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS) to commence on or around December 2021. GEN-2017-027 is in the SPP cluster study group DISIS-2017-001.

SPP provided an approved scope[1] for the IASIS (the Study Scope) that covered the types of analyses to be performed in the study, models to be used, system to be monitored, study criteria, prior-queued projects to be considered and the types of contingencies to be tested.

Power flow, transient stability, short circuit, and reactive compensation analyses were conducted for this IASIS. Interim Availability System Impact Studies are conducted under GIA Section 11A[3].

The IASIS considers the Base Case as well as all Generating Facilities (and with respect to (b) below, any identified Network Upgrades associated with such higher queued interconnection projects) that, on the date the IASIS is commenced:

a) are directly interconnected to the Transmission System;
b) are interconnected to Affected Systems and may have an impact on the Interconnection Request;
c) have a pending higher queued Interconnection Request to interconnect to the Transmission System listed in Table 1-1; or
d) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC.

Any changes to these assumptions may require a re-study of this IASIS.

This IASIS study included prior queued generation interconnection requests in DISIS-2016-002 and higher, as defined in *Appendix B: Requests of the IASIS Scope* and are tabulated in Table 1-1. The higher or equally queued projects that were excluded in this study scope are listed in Table 1-2.

3 http://opsportal.spp.org/documents/studies/SPP%20Tariff%20Attachment%20V%20Generator%20Interconnection%20Procedures.pdf

The only network upgrade that SPP suggested in *Appendix C: Network Upgrades of the IASIS Scope* is to exclude the second 138 kV line from G16-126 Tap to Arbuckle 138 kV. Since this line was not modeled in any base power flow cases that SPP provided, no network upgrade changes were made in this study.

Table 1-1: Higher Queued GI Requests Included within IASIS

Project	Total MW	Service Type	Fuel Source	POI	Queue Status
GEN-2011-040	110.0	ER/NR	Wind	Carter County 138 kV	IA FULLY EXECUTED/COMMERCIAL OPERATION
GEN-2011-050	109.8	ER	Wind	Santa Fe 138kV	IA FULLY EXECUTED/COMMERCIAL OPERATION
GEN-2012-004	41.4	ER/NR	Wind	Carter County 138 kV	IA FULLY EXECUTED/COMMERCIAL OPERATION
GEN-2013-007	100.0	ER/NR	Wind	Honey Creek 138kV	IA FULLY EXECUTED/COMMERCIAL OPERATION
GEN-2014-057	250.0	ER	Wind	Terry Road 345kV	IA FULLY EXECUTED/COMMERCIAL OPERATION
ASGI-2015-006	9.0	ER	Solar	Tupelo 138 kV	
GEN-2015-045	20.0	ER	Battery	Terry Road 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-092	110.0	ER	Wind	Terry Road 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-092	140.0	ER	Wind	Terry Road 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2015-036	303.6	ER	Wind	Johnston County 345kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-028	100.0	ER	Wind	Clayton 138 kV Sub	IA FULLY EXECUTED/COMMERCIAL OPERATION
GEN-2016-030	100.0	ER/NR	Solar	Brown 138kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-063	200.0	ER/NR	Wind	Hugo-Sunnyside 345 kV	IA FULLY EXECUTED/ON SCHEDULE
GEN-2016-102	150.9	ER/NR	Wind	Blue River 138kV	IA FULLY EXECUTED/ON SUSPENSION
GEN-2016-126	172.5	ER/NR	Wind	Arbuckle 138kV	IA FULLY EXECUTED/ON SCHEDULE

Table 1-2: Higher or Equally Queued GI Requests Excluded within IASIS

Project	Total MW	Service Type	Fuel Source	POI	Queue Status
GEN-2008-046	200.0	ER	Wind	Sunnyside 345 kV Sub	WITHDRAWN
GEN-2016-042	22.0	ER	Wind	Terry Road 345kV Sub	WITHDRAWN
GEN-2016-129	132.0	ER	Wind	Valiant 345 kV Sub	WITHDRAWN
GEN-2017-023	85.0	ER/NR	Solar	Hugo Power Plant 138 kV Sub	DISIS Study in progress
GEN-2017-024	50.0	ER/NR	Solar	Frogville 138 kV Sub	DISIS Study in progress
GEN-2017-066	150.8	ER/NR	Solar	Oney 138 kV Sub	DISIS Study in progress
GEN-2017-075	200.0	ER/NR	Solar	Hugo – Sunnyside 345 kV	DISIS Study in progress

2 Generating and Interconnection Facilities

2.1 Generating Facility

In the original interconnection application submitted in 2017, the Interconnection Customer's request to interconnect a total of 140 MW of generation consisted of seventy (70) Vestas 2.0 MW wind turbines and associated facilities.

2.2 Interconnection Facilities

The POI for GEN-2017-027 is the Carter County 138 kV substation that is located in Carter County, OK. The proposed GEN-2017-027 was modeled by using the following project file provided by SPP:

- "18.0DIS-17-1_ADD_GEN-2017-027 (power flow).idv"

Figure 2-1 depicts the one-line diagram of the local transmission system including the POI as well as the power flow model representing the request. The detailed parameters are presented in Section B.1 and were used in the power flow analysis.

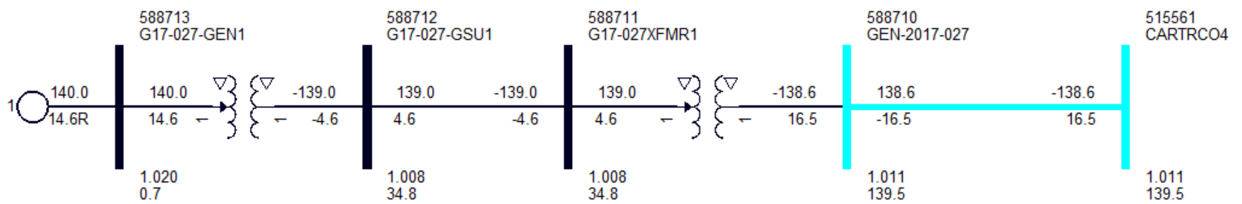


Figure 2-1: GEN-2017-027 Interconnection Facilities

2.3 Updated Generating and Interconnection Facilities

Subsequently in May 2021 after the power flow analysis had been completed (see Section 3 of this report), the Interconnection Customer updated the request at SPP Generation Interconnection Decision Point 2 such that the total of 140 MW is comprised of eleven (11) Vestas V110 VCS 2.2 MW Mk10C, twenty one (21) Vestas V120 VCS 2.2 MW Mk11D, nine (9) Vestas V150 CP 4.0 MW Mk3E, and eight (8) Vestas V150 CP 4.2 MW Mk3E turbines. The parameters of the associated facilities were also slightly changed. The updated project design is illustrated below in Figure 2-2. Detailed project data can be found in Sections B.2 and B.3. A comparison of Figure 2-1 and Figure 2-2 shows that although the gross output of the wind farm is 140 MW, the net injection at the Carter County 138 kV bus is slightly lower with the updated facilities (136.3 MW) than with the originally proposed facilities (138.6 MW).

The updated project design was used in the stability analysis, short circuit analysis, and reactive compensation analysis.

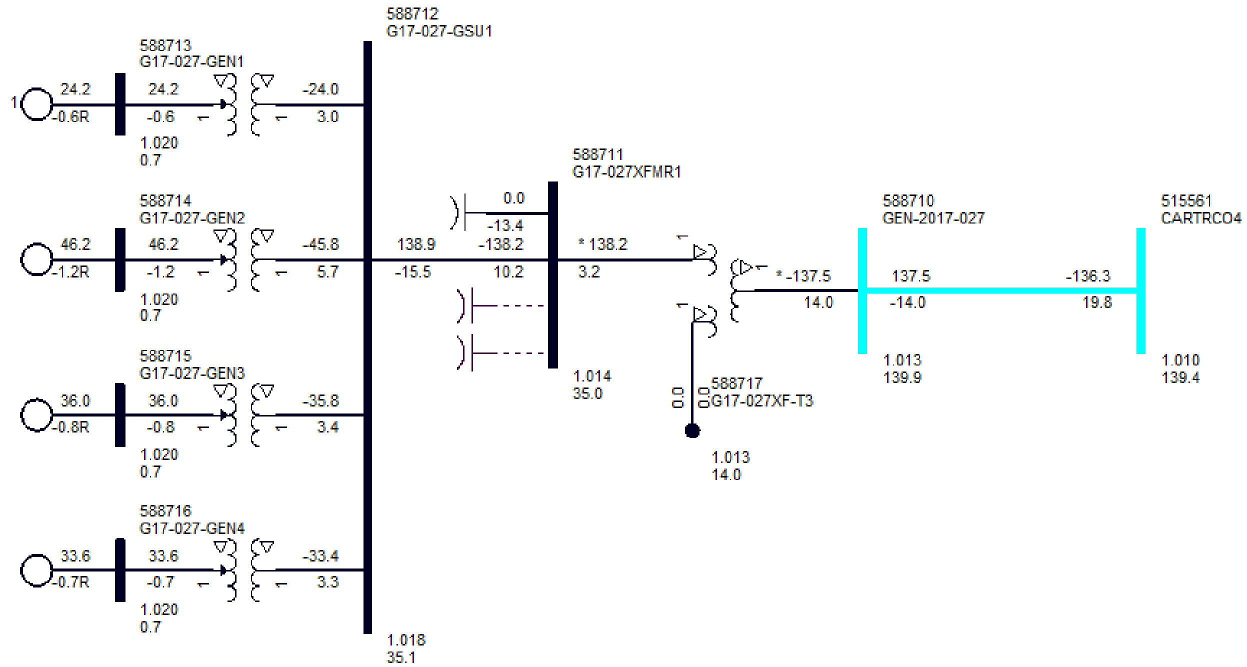


Figure 2-2: GEN-2017-027 Updated Interconnection Facilities

2.4 Base Case Upgrades

The Network Upgrades included within the cases used in this IASIS study are those facilities that are a part of the SPP Transmission Expansion Plan, Balanced Portfolio that have in-service dates prior to the GEN-2017-027 requested in-service date of December 2021. The IASIS study used the DISIS-2016-002 series models which include the network upgrades associated with prior queued requests. No additional network upgrades were included in the models.

3 Power Flow Analysis

Power flow analysis is used to determine if the transmission system can accommodate the injection from the request without violating thermal or voltage criteria.

3.1 Model Development

Power flow analysis was performed using the DISIS-2016-002 series study models, including the 2017 Winter Peak (17WP), 2018 Spring (18G) and Summer Peak (18SP), 2021 Light (21L), 2021 Summer (21SP) and Winter Peak (21WP), and 2026 Summer Peak (26SP) seasonal models. The starting ERIS and NRIS power flow models provided by SPP are tabulated below in Table 3-1.

Table 3-1: Base Cases for Power Flow Analysis

Base Case*	Dispatch (Group)	Seasons
DISIS-2016-002_Group14_ERIS_S0	HVER (14)	17WP, 18G, 18SP, 21SP, 21WP, 26SP
BASE-DIS1602-21L0_2020-08-29-1700	HVER (14)	21L
DISIS-2016-002_Group00_NRIS_S0	NR (00)	17WP, 18SP, 21SP, 21WP, 26SP
DISIS-2016-002_Group14_NRIS_S0	NR (14)	18G, 21L

* These Base Cases are the Transfer Cases from the DISIS-2016-002 package.

Change IDEV files were created and applied to the models in Table 3-1 to make following modifications in accordance with Appendix B and C of the IASIS Scope:

- Add GEN-2017-027 into the models.
- Move the POI of GEN-2016-126 to Arbuckle 138 kV.
- Disconnect withdrawn request GEN-2016-129 and associated facilities.

The modified ERIS and NRIS models were transmitted to SPP, who created the Base Cases (BC) and Transfer Cases (TC) by dispatching the interconnection requests in accordance with DISIS Manual[4], Business Practices 7250 and 7350. As outlined in Section of Power Flow Analysis Models Dispatch of the IASIS Scope, the HVER dispatch scenario for this study is such that:

- Variable Energy Resources (VER) (solar/wind) within Group 14 are dispatched at 100% nameplate of maximum generation.
- All Summer, Winter, and Spring HVER cases are dispatched from the DISIS-2016-002 dispatched cases which use a 20% dispatch for out-of-group requests.
- The HVER LL case is dispatched from the Base Case using a 0% dispatch for out-of-group requests.
- The NR cases (Group 14 for G and LL, Group 00 for SP and WP) are dispatched from the DISIS-2016-002 dispatched cases which have dispatch variations based on seasonal

[4] http://opsportal.spp.org/documents/studies/DISIS_Manual.pdfs

case (G and LL or SP and WP), service type (ER or ER/NR), and fuel type (renewable or conventional).

- Each request is dispatched across the SPP footprint using load factor ratios.

For each type of analysis (ERIS and NRIS analysis), SPP provided seven (7) BC models and seven (7) TC models to use in this study. These cases were used without further modification.

3.2 Study Methodology and Criteria

Network constraints were identified by using PSS/E AC Contingency Calculation (ACCC) analysis with PSS/E MUST First Contingency Incremental Transfer Capability (FCITC) analysis on the entire cluster grouping dispatched at the various levels previously mentioned.

For Energy Resource Interconnection Service (ERIS), thermal overloads are determined for system intact (n-0) (greater than 100% of Rate A – normal) and for contingency (n-1) (greater than 100% of Rate B – emergency) conditions.

The overloads are then screened to determine which of generator interconnection requests have at least

- 3% Distribution Factor (DF) for system intact conditions (n-0),
- 20% DF upon outage based conditions (n-1), or
- 3% DF on contingent elements that resulted in a non-converged solution.

Interconnection Requests that requested Network Resource Interconnection Service (NRIS) are also studied in a separate NRIS analysis to determine if any constraint measured greater than or equal to a 3% DF. If so, these constraints are also considered for transmission reinforcement under NRIS.

SPP's voltage criteria are applied to all facilities at 69 kV and greater in the study region in the absence of more stringent criteria:

- 0.95 ~ 1.05 per unit for system intact conditions (N-0),
- 0.90 ~ 1.05 per unit for outage-based conditions (N-n)

Areas and specific buses having more-stringent voltage criteria were specified in the monitoring file that SPP provided for this study. The voltage constraints identified through the voltage scan were screened for GEN-2017-027 and subject to the following criteria: 3% DF on the contingent element and a 2% change in per unit voltage between the TC and BC models.

The contingency set includes all SPP control area branches and ties 69kV and above, first-tier Non-SPP control area branches and ties 115 kV and above, any defined contingencies for these control areas, and generation unit outages for the SPP control areas with SPP reserve share program redispatch.

The monitored elements include all SPP control area branches, ties, and buses 69 kV and above, and all first-tier Non-SPP control area branches and ties 69 kV and above. NERC Power Transfer Distribution Flowgates for SPP and first tier Non-SPP control area are monitored. Additional NERC Flowgates are monitored in second tier or greater Non-SPP control areas. Voltage monitoring was performed for SPP control area buses 69 kV and above.

3.3 ERIS Results

Thermal constraints with TDFs calculated in the ERIS analysis can be found in Table 3-2 below and the contingency descriptions associated with the thermal violations are listed in Table 3-2. The results show no thermal constraints with GEN-2017-027 TDF > 3% under system intact conditions. There are two P4_2 contingencies (see Table 3-3) that resulted in overloads on 138 kV facilities and GEN-2017-027 has TDF >20% on the overloaded facilities. Since the rated voltage of the overloaded facilities is less than 300 kV, GEN-2017-027 is not required to mitigate the overloads caused by these two P4_2 contingencies (in accordance with the IASIS scope, post-contingency overloads following P4_2 contingencies are required to be mitigated only on facilities rated 300 kV and above).

No voltage violations were identified that are attributable to GEN-2017-027.

Non-converged contingencies were reviewed and GEN-2017-027 does not exhibit a DF > 3% on any contingent elements that resulted in a non-converged solution.

Table 3-2: Thermal Constraints Identified in the ERIS Analysis

Season	Source	Flow	Monitored Element	RATE A (MVA)	RATE B (MVA)	TDF	TC% LOADING	Contingency Name
17WP	GEN7_027	TO –>FROM	WLDHRST2 – RATLIFF2 69kV CKT 1	48	48	0.2190	133.3	80871
17WP	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	191	191	1.0000	151.1	80871
17WP	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	191	191	0.9595	103.7	81236
18G	GEN7_027	TO –>FROM	PAOLI– 4 – MAYSVIL4 138kV CKT 1	155	177	0.7811	100.9	80871
18G	GEN7_027	TO –>FROM	MAYSVIL4 – MAYSVLT4 138kV CKT 1	155	177	0.7811	102.2	80871
18G	GEN7_027	TO –>FROM	WLDHRST2 – RATLIFF2 69kV CKT 1	48	48	0.2189	137.6	80871
18G	GEN7_027	FROM–>TO	RATLIFF4 – PRARPNT4 138kV CKT 1	155	177	0.7811	115.4	80871
18G	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	155	177	1.0000	163.0	80871
18G	GEN7_027	FROM–>TO	PRARPNT4 – MAYSVLT4 138kV CKT 1	155	177	0.7811	102.4	80871
18G	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	155	177	0.9595	112.9	81236
18SP	GEN7_027	TO –>FROM	MAYSVIL4 – MAYSVLT4 138kV CKT 1	155	177	0.7812	101.0	80871
18SP	GEN7_027	TO –>FROM	WLDHRST2 – RATLIFF2 69kV CKT 1	48	48	0.2188	139.1	80871
18SP	GEN7_027	FROM–>TO	RATLIFF4 – PRARPNT4 138kV CKT 1	155	177	0.7812	115.1	80871
18SP	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	155	177	1.0000	163.0	80871
18SP	GEN7_027	FROM–>TO	PRARPNT4 – MAYSVLT4 138kV CKT 1	155	177	0.7812	101.2	80871
18SP	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	155	177	0.9595	106.6	81236
21L	GEN7_027	TO –>FROM	PAOLI– 4 – MAYSVIL4 138kV CKT 1	155	177	0.7810	109.4	80871
21L	GEN7_027	TO –>FROM	MAYSVIL4 – MAYSVLT4 138kV CKT 1	155	177	0.7810	109.9	80871
21L	GEN7_027	TO –>FROM	WLDHRST2 – RATLIFF2 69kV CKT 1	48	48	0.2190	124.8	80871
21L	GEN7_027	FROM–>TO	RATLIFF4 – PRARPNT4 138kV CKT 1	155	177	0.7810	121.7	80871
21L	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	155	177	1.0000	163.2	80871
21L	GEN7_027	FROM–>TO	PRARPNT4 – MAYSVLT4 138kV CKT 1	155	177	0.7810	110.2	80871
21L	GEN7_027	FROM–>TO	RATLIFF4 – PRARPNT4 138kV CKT 1	155	177	1.0000	108.3	81236
21L	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	155	177	0.9595	118.5	81236
21SP	GEN7_027	TO –>FROM	MAYSVIL4 – MAYSVLT4 138kV CKT 1	155	177	0.7812	100.9	80871
21SP	GEN7_027	TO –>FROM	WLDHRST2 – RATLIFF2 69kV CKT 1	48	48	0.2188	138.2	80871
21SP	GEN7_027	FROM–>TO	RATLIFF4 – PRARPNT4 138kV CKT 1	155	177	0.7812	115.1	80871

Season	Source	Flow	Monitored Element	RATE A (MVA)	RATE B (MVA)	TDF	TC% LOADING	Contingency Name
21SP	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	155	177	1.0000	163.0	80871
21SP	GEN7_027	FROM–>TO	PRARPNT4 – MAYSVLT4 138kV CKT 1	155	177	0.7812	101.2	80871
21SP	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	155	177	0.9595	105.6	81236
21WP	GEN7_027	TO –>FROM	WLDHRST2 – RATLIFF2 69kV CKT 1	48	48	0.2190	131.9	80871
21WP	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	191	191	1.0000	151.1	80871
21WP	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	191	191	0.9595	102.5	81236
26SP	GEN7_027	TO –>FROM	WLDHRST2 – RATLIFF2 69kV CKT 1	48	48	0.2188	140.3	80871
26SP	GEN7_027	FROM–>TO	RATLIFF4 – PRARPNT4 138kV CKT 1	155	177	0.7812	113.8	80871
26SP	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	155	177	1.0000	163.0	80871
26SP	GEN7_027	FROM–>TO	PRARPNT4 – MAYSVLT4 138kV CKT 1	155	177	0.7812	100.1	80871
26SP	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	155	177	0.9595	103.1	81236

Table 3-3: Contingency Descriptions for Thermal Constraints

Contingency Name	Contingency Description
80871	Carter County – Pooleville 138 kV line circuit 1 and Carter County – Sunnyside 138 kV circuit 1
81236	Sunnyside – Lone Grove 138 kV circuit 1, Sunnyside – Carter County 138 kV circuit 1

3.4 NRIS Results

Thermal constraints with TDFs calculated in the NRIS analysis can be found in Table 3-4 below. As in the ERIS analysis, the same two P4_2 contingencies listed in Table 3-3 that resulted in constraints on 138 kV facilities are attributed to GEN-2017-027. No mitigation is required as per the IASIS Scope provided by SPP.

No voltage violations attributed to GEN-2017-027 were identified. However, it is noticed that the NRIS 21W Base Case (BC) is not as robust as the other cases and voltage collapse is observed following multiple events. More contingencies resulted in voltage collapse in the 21W BC case than in the 21W Transfer Case (TC) cases. As such, some voltages that are flagged in the TC cases could not be compared against the corresponding BC case values.

Non-converged contingencies in the Transfer Case (TC) were reviewed. GEN-2017-027 does not exhibit a DF > 3% on any contingent elements that resulted in a non-converged solution.

3.5 Updated Generating and Interconnection Facilities

As mentioned in Section 2.3, the Interconnection Customer updated the project design at the Decision Point 2, after the power flow analysis was completed. Due to the proposed project data changes, the net MW injection of the proposed project is reduced from 138.6 MW as shown in Figure 2-1 to approximately 136.3 MW as in Figure 2-2.

The reduction of approximately 2.3 MW of injection is not considered to be significant enough to have any material impact on the system thermal or voltage performance. As such, SPP confirmed during the status meeting on May 25, 2021 that there is no need to re-run power flow analysis using the updated project data that the Interconnection Customer submitted at Decision Point 2.

Table 3-4: Thermal Constraints Identified in the NRIS Analysis

Season	Source	Flow	Monitored Element	RATE A (MVA)	RATE B (MVA)	TDF	TC% LOADING	Contingency Name
17WP	GEN7_027	TO –>FROM	WLDHRST2 – RATLIFF2 69kV CKT 1	48	48	0.2174	153.5	80871
17WP	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	191	191	1.0000	151.1	80871
17WP	GEN7_027	FROM–>TO	RATLIFF 138/69/13.2 kV XFMR	62	67	0.2174	108.2	80871
17WP	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	191	191	0.9595	103.7	81236
18G	GEN7_027	TO –>FROM	PAOLI– 4 – MAYSVIL4 138kV CKT 1	155	177	0.7826	100.1	80871
18G	GEN7_027	TO –>FROM	MAYSVIL4 – MAYSVLT4 138kV CKT 1	155	177	0.7826	101.3	80871
18G	GEN7_027	TO –>FROM	WLDHRST2 – RATLIFF2 69kV CKT 1	48	48	0.2174	140.6	80871
18G	GEN7_027	FROM–>TO	RATLIFF4 – PRARPNT4 138kV CKT 1	155	177	0.7826	114.5	80871
18G	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	155	177	1.0000	163.0	80871
18G	GEN7_027	FROM–>TO	PRARPNT4 – MAYSVLT4 138kV CKT 1	155	177	0.7826	101.6	80871
18G	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	155	177	0.9595	113.0	81236
18SP	GEN7_027	TO –>FROM	WLDHRST2 – RATLIFF2 69kV CKT 1	48	48	0.2170	158.0	80871
18SP	GEN7_027	FROM–>TO	RATLIFF4 – PRARPNT4 138kV CKT 1	155	177	0.7830	109.9	80871
18SP	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	155	177	1.0000	163.0	80871
18SP	GEN7_027	FROM–>TO	RATLIFF2 – RATLIFF2 WND 1kV CKT 1	62	67	0.2170	112.5	80871
18SP	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	155	177	0.9595	106.6	81236
21L	GEN7_027	TO –>FROM	PAOLI– 4 – MAYSVIL4 138kV CKT 1	155	177	0.7827	106.6	80871
21L	GEN7_027	TO –>FROM	MAYSVIL4 – MAYSVLT4 138kV CKT 1	155	177	0.7827	107.1	80871
21L	GEN7_027	TO –>FROM	WLDHRST2 – RATLIFF2 69kV CKT 1	48	48	0.2173	134.7	80871
21L	GEN7_027	FROM–>TO	RATLIFF4 – PRARPNT4 138kV CKT 1	155	177	0.7827	119.1	80871
21L	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	155	177	1.0000	163.4	80871
21L	GEN7_027	FROM–>TO	PRARPNT4 – MAYSVLT4 138kV CKT 1	155	177	0.7827	107.4	80871
21L	GEN7_027	FROM–>TO	RATLIFF4 – PRARPNT4 138kV CKT 1	155	177	1.0000	108.1	81236
21L	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	155	177	0.9595	118.5	81236
21SP	GEN7_027	TO –>FROM	WLDHRST2 – RATLIFF2 69kV CKT 1	48	48	0.2170	157.7	80871
21SP	GEN7_027	FROM–>TO	RATLIFF4 – PRARPNT4 138kV CKT 1	155	177	0.7830	109.8	80871

Season	Source	Flow	Monitored Element	RATE A (MVA)	RATE B (MVA)	TDF	TC% LOADING	Contingency Name
21SP	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	155	177	1.0000	163.0	80871
21SP	GEN7_027	FROM–>TO	RATLIFF2 – RATLIFF2 WND 1kV CKT 1	62	67	0.2170	112.0	80871
21SP	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	155	177	0.9595	105.7	81236
21WP	GEN7_027	TO –>FROM	WLDHRST2 – RATLIFF2 69kV CKT 1	48	48	0.2174	153.3	80871
21WP	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	191	191	1.0000	151.1	80871
21WP	GEN7_027	FROM–>TO	RATLIFF4 – RATLIFF2 WND 2kV CKT 1	62	67	0.2174	108.0	80871
21WP	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	191	191	0.9595	102.6	81236
26SP	GEN7_027	TO –>FROM	WLDHRST2 – RATLIFF2 69kV CKT 1	48	48	0.2170	162.4	80871
26SP	GEN7_027	FROM–>TO	RATLIFF4 – PRARPNT4 138kV CKT 1	155	177	0.7830	107.8	80871
26SP	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	155	177	1.0000	163.0	80871
26SP	GEN7_027	TO –>FROM	HEALDTN2 – COUTYTP2 69kV CKT 1	49	56	0.2170	102.0	80871
26SP	GEN7_027	FROM–>TO	RATLIFF4 – RATLIFF2 WND 2kV CKT 1	62	67	0.2170	114.7	80871
26SP	GEN7_027	TO –>FROM	RATLIFF4 – CARTRCO4 138kV CKT 1	155	177	0.9595	103.2	81236

4 Transient Stability Analysis

Transient stability analysis is used to determine if the transmission system can maintain angular stability and ensure bus voltages stay within planning criteria during and after a disturbance while considering the addition of a generator interconnection request.

4.1 Model Development

Transient stability analysis was performed using modified versions of the 2016 series of Model Development Working Group (MDWG) dynamic study models and included the 2017 winter peak (2017W), 2018 summer peak (2018S) and 2026 summer peak (2026S) dynamic cases. The following three data packages were provided by SPP as the starting point for the transient stability analysis:

- MDWG16-17W_DIS1602_G14.sav
- MDWG16-18S_DIS1602_G14.sav
- MDWG16-26S_DIS1602_G14.sav

Based on the above three cases, the "pre-project" cases were created by making following adjustments:

- Move the POI of GEN-2016-126 to Arbuckle 138 kV.
- Disconnect withdrawn request GEN-2016-129 and associated facilities.

The "post-project" cases were created by adding the proposed GEN-2017-027 using the updated project data documented in Section 2.3. The GEN-2017-027 generation was dispatched into the SPP footprint by using the following subsystem file that was provided by SPP:

- MDWG16_SPP_Scale_Subsystem.idv

Initial simulations are carried out for a no-disturbance run of twenty (20) seconds to verify the numerical stability of the model.

4.2 Disturbances

Seventy-five (75) contingencies were identified for use in this study. These contingencies included three-phase faults and single-phase line faults at locations suggested by SPP. Single-phase line faults were simulated by applying fault impedance to the positive sequence network at the fault location to represent the effect of the negative and zero sequence networks on the positive sequence network. The fault impedance was computed to give a positive sequence voltage at the specified fault location of approximately 60% of pre-fault voltage. This method is in agreement with SPP current practice and defined in the Study Scope.

With exception to transformers, the typical sequence of events for a three-phase fault (P1 and P6) is as follows:

a. apply fault at particular location
b. continue fault for seven (7) cycles (6 cycles for 345 kV), clear the fault by tripping the faulted facility
c. after an additional twenty (20) cycles, re-close the previous facility back into the fault

d. continue fault for seven (7) additional cycles, trip the faulted facility and remove the fault

The typical sequence of events for a single-phase fault (P4) with stuck breaker would be as follows:

a. apply fault at particular location

b. clear fault after 16 cycles and trip all elements sharing the stuck breaker.

Additionally, the sequence of events for a transformer is to: 1) apply a three-phase fault for seven (7) cycles, and 2) clear the fault by tripping the affected transformer facility. Unless otherwise noted there will be no re-closing into a transformer fault.

The list of fault events is included in Appendix D.

4.3 Study Methodology and Criteria

4.3.1 Study Methodology

All fault events listed in Appendix D were first simulated using the post-project cases and the results were reviewed. For events that exhibited stability criteria violations, the pre-project case was simulated such that the stability performance with and without the proposed interconnection project could be compared. Any new stability problems attributed to the proposed interconnection projects are flagged and reported.

For each fault, rotor angles, speed deviations, and electrical power outputs of the study generators and the generators in the proximity were monitored. Voltages at selected buses, including the POI bus of the study project and all faulted buses, were also monitored.

Dynamic simulations were performed using the PSS/E version 33.10. In each simulation, the fault is initiated at t = 2.0 seconds and the total simulation run time 20 seconds.

Note that P6 event prior outage conditions were implemented in the unconverted cases followed by a steady-state solution prior to converting the case for transient analysis.

4.3.2 Study Criteria

The transient stability criteria specified in the Study Scope are shown below for reference:

Rotor angle criteria

For each fault event, verify that rotor angle oscillations of synchronous machines meet the damping requirements described in SPP Disturbance Performance Requirements[5], i.e. each rotor angle with at least a 16 degree spread in simulation must have a damping ratio of at least 0.0081633.

Additionally, the real power, reactive power, and, if applicable, speed response of asynchronous machines return without cessation to pre-event levels with a damped (ratio of at least 0.0081633) response. A controlled ramped response within 2.5 seconds following fault clearing is acceptable. Power cessation or return to low voltage response after adequate voltage recovery, for example after terminal voltage recovers above 0.9 pu, is not acceptable.

[5] https://www.spp.org/documents/28859/spp%20disturbance%20performance%20requirements%20(twg%20approved).pdf

For certain instances in which the waveforms may not conform with the latest version of the performance requirements, engineering judgement will be allowed to determine whether rotor angles have adequate damping and voltages adequately recover from a fault.

Steady-state voltage criteria

The criteria for Steady-State voltage violations is evaluated and reported for P0, P1, P4, and P6 events on the stability analysis cases both prior to the event (t=0) and with the system values at the end of the simulation (t=20). Initial steady state voltages should be between 0.95 pu and 1.05 pu and recovery should be at least 0.9 pu and not more than 1.1pu. Mitigation of these steady-state violations in the Stability Analysis is not required but switchable reactive equipment and adjustable transformers in the vicinity of the constraint will be evaluated and results reported.

Transient voltage response

For each fault event, the voltage response of the terminal bus, POI substation bus, and Transmission System buses greater than 100kV within 5 buses of each POI shall remain within the acceptable limits established in SPP Disturbance Performance Requirements[6], i.e., measured voltages remain below 1.2 pu and recover and remain above 0.7 pu within 2.5 following fault clearing. In addition to maintaining this bandwidth, voltages must have a damped (i.e. ratio of at least 0.0081633) response to demonstrate that the system remains stable.

Fault Ride-through

Load and generation loss as necessary to clear a fault is acceptable as a consequence of a fault event. Non-consequential protective relays, power cessation, or other tripping on the system is generally not permissible. In accordance with FERC Order 661-A and NERC PRC-024-2, any unit tripping for fault events with normal clearing, except for islanded facilities, is generally an unstable response.

4.4 Study Results

4.4.1 Preliminary Results

The initial pass of simulations identified multiple P4 and P6 faults under which GEN-2017-027 and the neighboring Origin Wind Project, which shares the same point of interconnection at Carter County 138 kV, exhibit oscillatory responses after fault clearing.

Figure 4-1 and Figure 4-2 below illustrate respectively the real power output and reactive power output from each aggregated units of GEN-2017-027 and the Origin Wind Project following the fault event FLT_45, which is a P4 fault applied at the Sunnyside 138 kV bus (the real and reactive power outputs are plotted in per unit on system base i.e., 100 MVA base). The fault is cleared after 16 cycles by tripping the Sunnyside to Carter County 138 kV line and all sections between the Sunnyside 138 kV and the Healdton Tap 138 kV. The cyclical triggering of the low voltage ride-through module at Origin Wind appears to have caused the oscillatory voltage response at the generator terminal buses, which result in the undamped voltage oscillation at the POI and the surrounding 138 kV buses, as shown in Figure 4-3. Reducing the clearing time to 7 cycles does

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

not mitigate the oscillation. The same fault FLT_45 was repeated using the pre-project case and the oscillatory response was not observed. Therefore, the oscillation is considered to be attributed to the interconnection of GEN-2017-027.

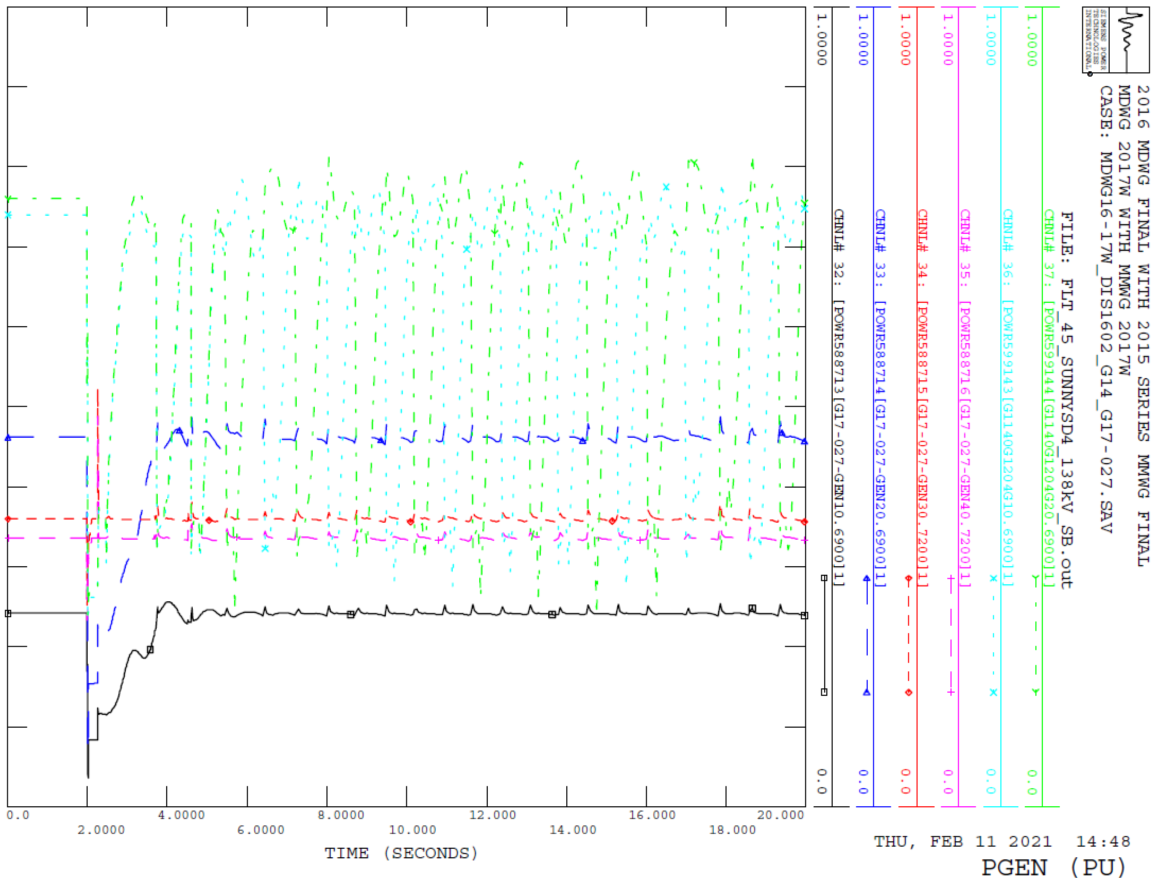


Figure 4-1: Pgen of GEN-2017-027 and Origin Wind under FLT_45 (2017WP)

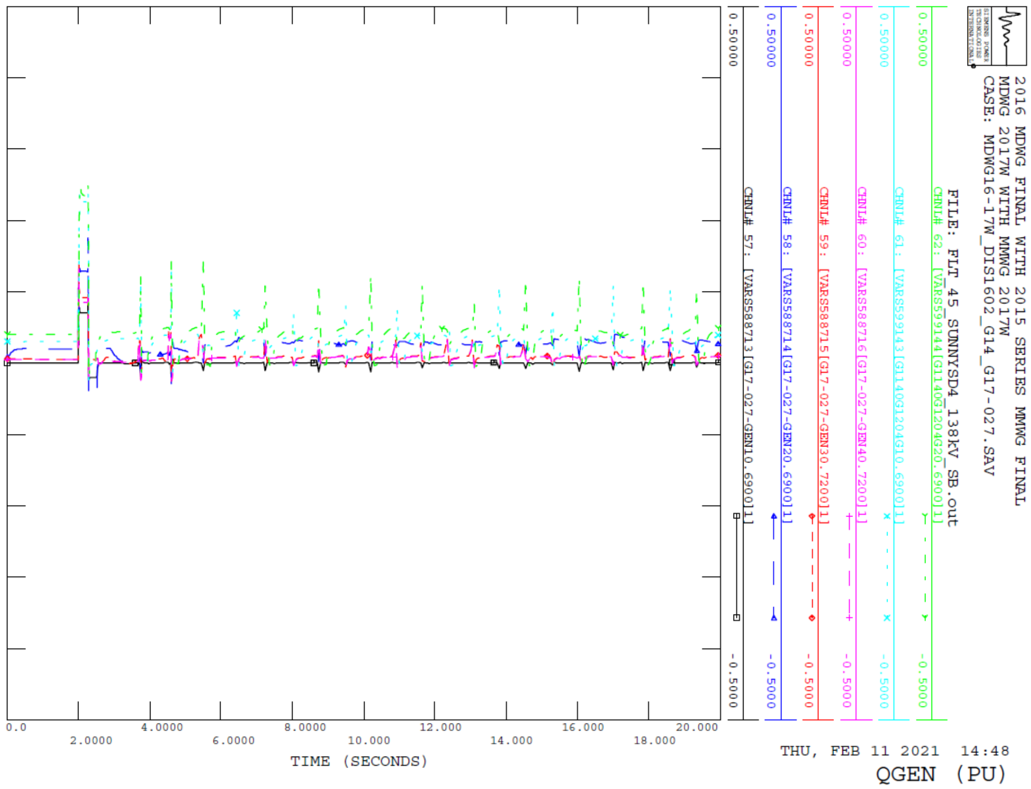


Figure 4-2: Qgen of GEN-2017-027 and Origin Wind under FLT_45 (2017WP)

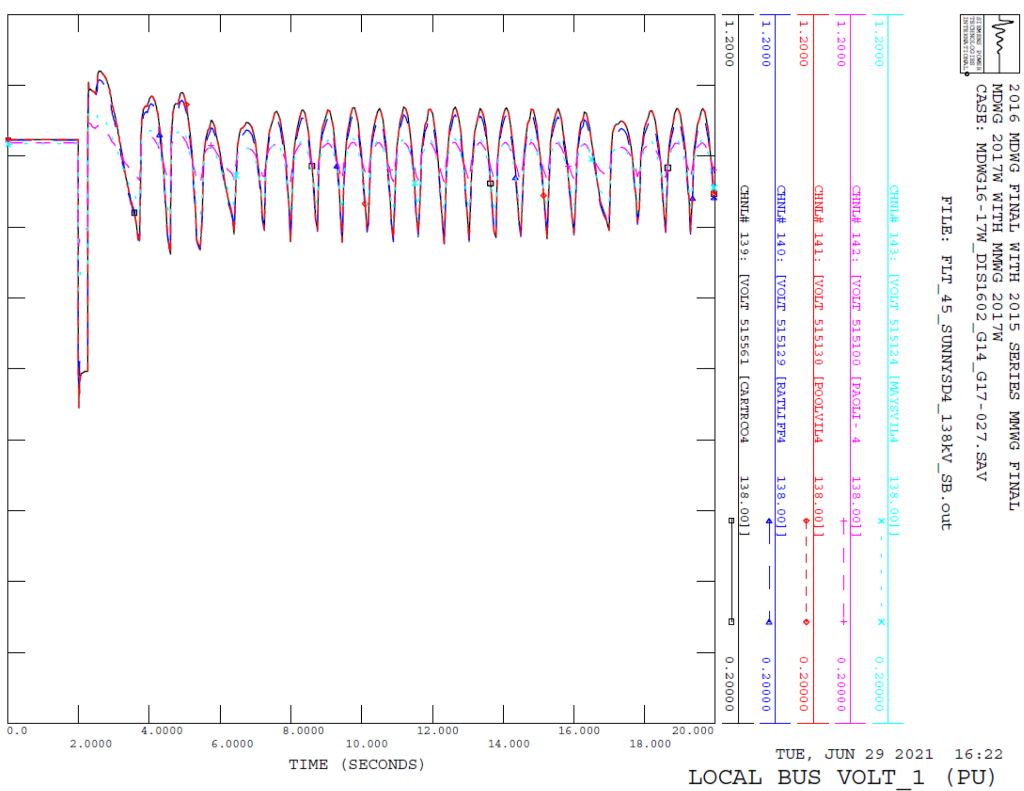


Figure 4-3: Local 138 kV Bus Voltages under FLT_45 (2017WP)

Further investigation was carried out by calculating the Short Circuit Ratio (SCR) at the Carter County 138 kV bus using the 2017 Winter Peak case for several problematic fault conditions.

SCR is defined as the ratio between short circuit apparent power (SCMVA) from a three-phase fault at a given location in the power system to the rating of the inverter-based resource connected to that location. According to the NERC Reliability Guideline on Integrating Inverter-Based Resources into Low Short Circuit Strength System[7], a low SCR area ("weak system") indicates high sensitivity of voltage (magnitude and phase angle) to changes in active and reactive power injection or consumption. For the purposes of this study, the SCRs were calculated by applying a three-phase fault at the Carter County 138 kV bus with the Rockhaven and Origin wind projects off-line and dividing the resulting SCMVA at the Carter County 138 kV bus by the combined gross output of these two wind projects (290 MW). The post-fault SCRs, which are presented here for informational purposes only and listed Table 4-1 are rather low, which indicate weak grid issues under these faults. In such cases, coordination and engagement with the wind turbine generator manufacturer is critical in identifying suitable mitigation to ensure a stable and well-damped response for the given weak grid issue.

Table 4-1: SCRs at POI in 2017WP Case

Prior Outage	Contingency	SCMVA	SCR
None	System Intact	1618.18	5.58
	FLT_45: Sunnyside - Carter Co. 138 kV Line	396.83	1.37
PO1: Carter County – Sunnyside 138 kV Line	FLT_60: Carter County - Ratliff 138 kV Line	560.78	1.93
	FLT_61: Carter County – Healdton Tap 138 kV Line	484.68	1.67
	FLT_62: Sunnyside – Healdton Tap 138 kV Line	396.83	1.37
PO2: Carter County – Healdton Tap 138 kV Line	FLT_64: Carter County - Ratliff 138 kV Line	955.02	3.29
PO3: Carter County – Ratliff 138 kV Line	FLT_66: Carter County - Sunnyside 138 kV Line	560.78	1.93

The above findings were discussed with Enel who then contacted the wind turbine generator manufacturer, Vestas, to assist with the specific stability related concerns. As part of the effort to mitigate the oscillatory voltage responses, Vestas undertook considerable analysis of the projects and the surrounding grid. Vestas' analysis, performed in PSCAD for the Rockhaven and Origin Wind projects, resulted in the need for relevant control parameter changes to be implemented at the projects to improve performance related issues caused by low short circuit strength. The parameter changes at Rockhaven and Origin include updates to the Power Plant Controller (PPC) and wind turbine parameters to ensure stable operation. After the completion of the PSCAD analysis, Vestas updated the PSS/E models for the Rockhaven and Origin wind farms and provided them to Enel for use in this study. In addition, Vestas recommended that the bus voltages at Carter County 138 kV be adjusted to a minimum of 1.03 pu under pre-contingency conditions in order to mitigate stability issues due to low short circuit strength.

[7] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Item_4a._Integrating%20_Inverter-Based_Resources_into_Low_Short_Circuit_Strength_Systems_-_2017-11-08-FINAL.pdf

4.4.2 Updated Results

As noted above, Vestas performed additional studies in PSCAD to investigate the oscillatory responses described above in Section 4.4.1. After the completion of the additional studies, Vestas updated the PSS/E models for the GEN-2017-027 project and provided them to Enel for use in this study. Vestas also provided the updated control parameters for this project which are documented in Appendix B.3. Furthermore, a new set of dynamic models and parameters for the existing Origin Wind Project were provided and are included in Appendix C.2.

All fault events proposed in Appendix D were re-simulated using the updated dynamic models for GEN-2017-027 and the Origin Wind Project for all three cases.

Based on the dynamic results, GEN-2017-027 did not cause any stability problems and remained stable for all faults studied. Fault 45 was repeated on the 2017 Winter Peak case with the updated models for GEN-2017-027 and Origin Wind and the results corresponding to Figure 4-1 through Figure 4-3 are plotted in Figure 4-4 through Figure 4-6. It is seen that the response is stable and that there are no oscillations. Additionally, GEN-2017-027 was found to remain connected during the contingencies that were studied and therefore, meets the voltage and frequency ride through requirements of FERC Order 661-A and NERC PRC-024-2.

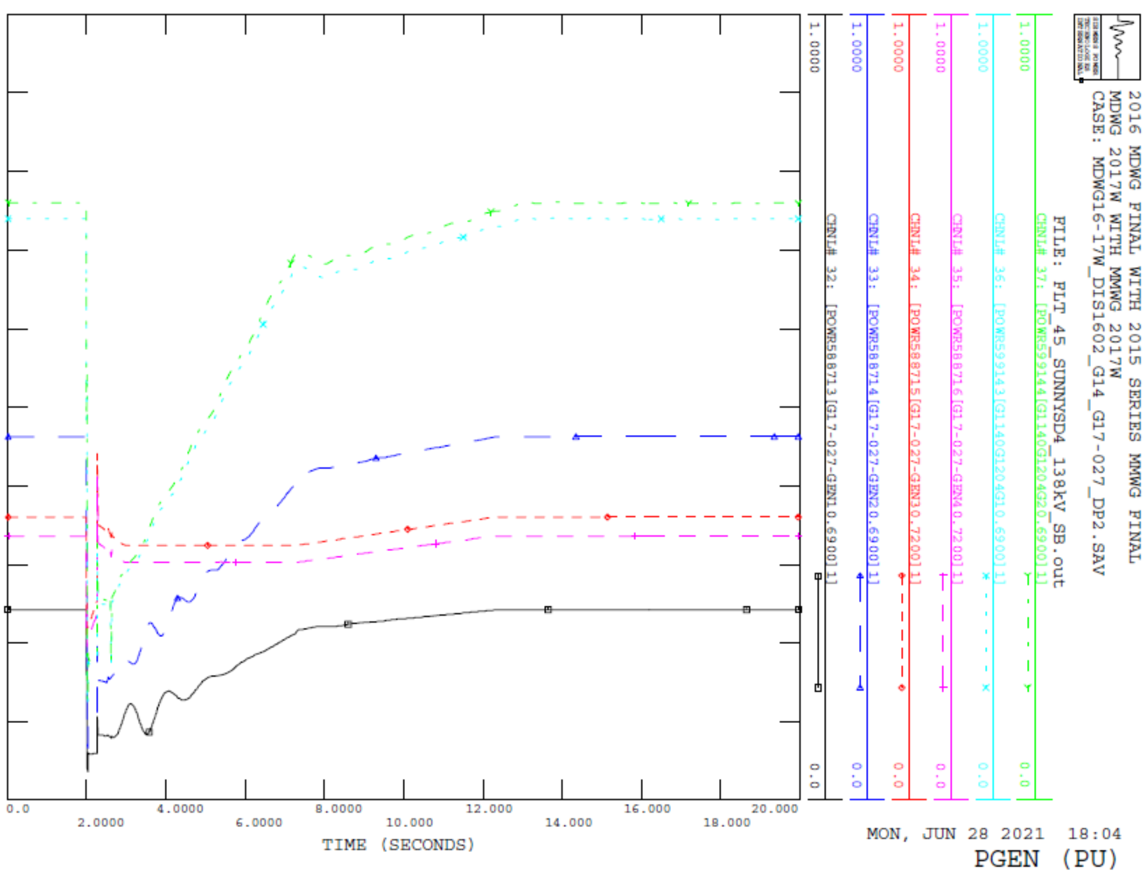


Figure 4-4: Pgen of GEN-2017-027 and Origin Wind under FLT_45 using Updated Dynamic Data (2017WP)

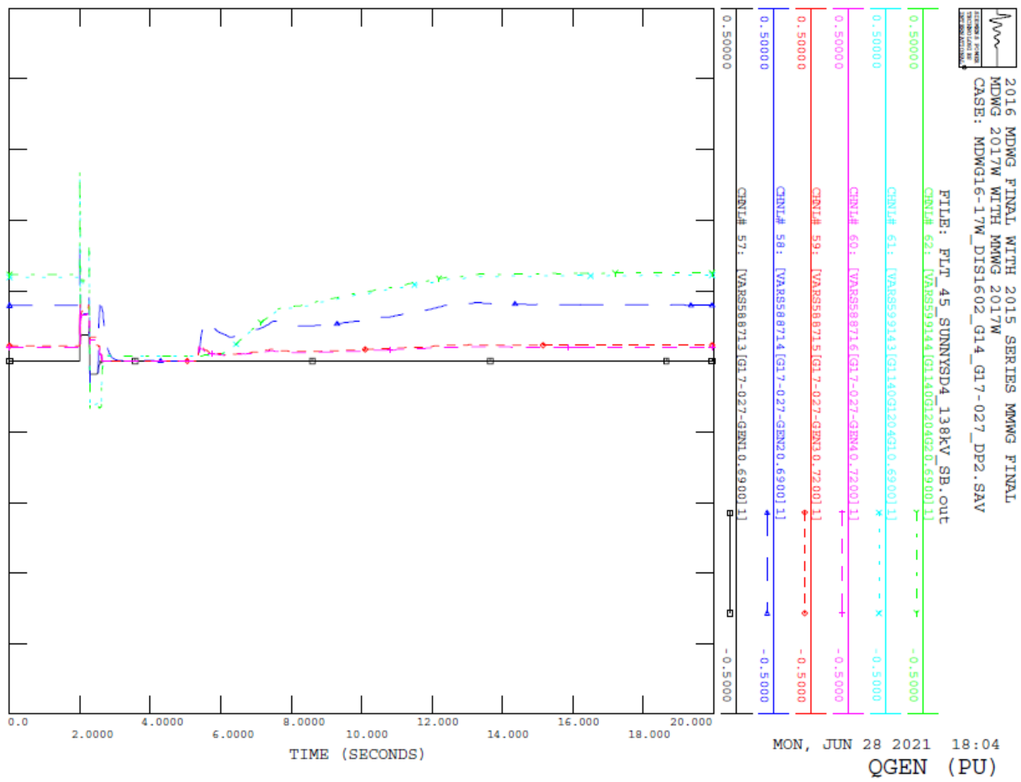


Figure 4-5: Qgen of GEN-2017-027 and Origin Wind under FLT_45 using Updated Dynamic Data (2017WP)

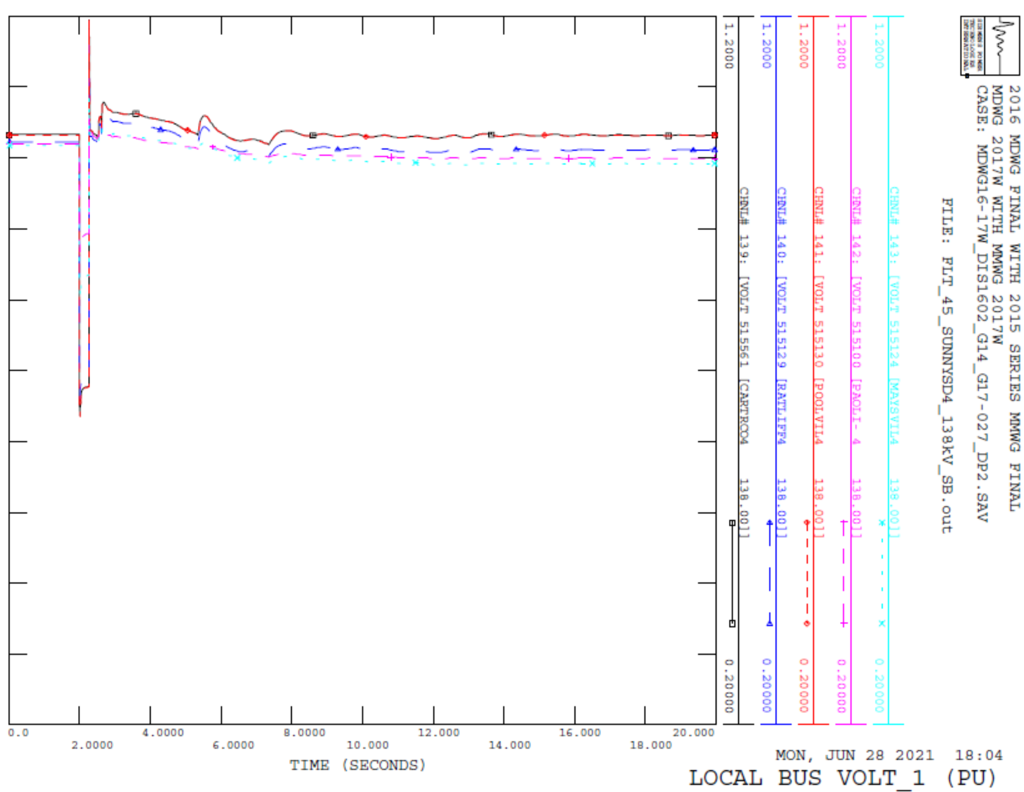


Figure 4-6: Local 138 kV Bus Voltages under FLT_45 using Updated Dynamic Data (2017WP)

Certain faults simulated on the 2026 Summer Peak case exhibited a “chatter” in the post-fault voltage response at the POI, as illustrated below in Figure 4-7. FLT_01 assumes a 3-PH fault applied at Carter County 138 kV, which resulted in the tripping of the Carter County to Ratliff 138 kV line. This chatter was discussed with Vestas staff who indicated that this may be a consequence of approximations in the wind turbine generator and PPC models in PSS/E and that they did not observe similar issues in their PSCAD simulations. As suggested in the NERC Reliability Guideline, a detailed PSCAD study provides more accurate stability results than PSS/E due to the specific modeling requirements and a smaller simulation time step. All faults that resulted in a chatter were reviewed and were found to be in compliance with SPP voltage criteria. The local 138 kV bus voltages remain in the bandwidth of 0.7 pu to 1.2 pu and damped within 2.5 seconds after the fault clearing.

It is therefore concluded the project GEN-2017-027 does not adversely impact system stability performance.

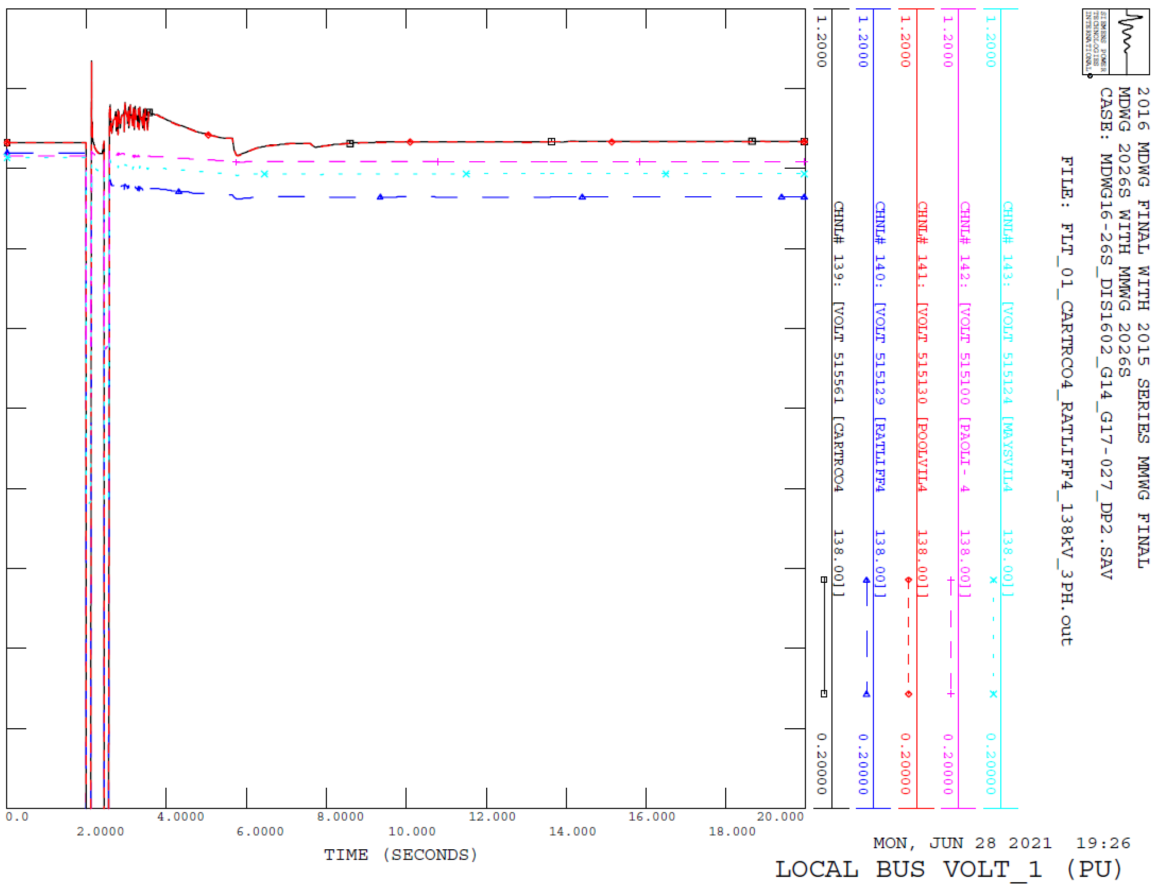


Figure 4-7: Local 138 kV Bus Voltages under FLT_01 (2026SP)

Results of the stability analysis are summarized below in Table 4-2. In the 2017WP case, there are several faults that resulted in non-convergence. The same faults were repeated using the 2017WP pre-project case and the same issue was identified. The non-convergence issue is thus not considered to be attributed to GEN-2017-027. A complete set of simulation plots is provided in Appendix F.

Table 4-2: Transient Stability Results

Cont. No	Contingency Name	2017WP		2018SP	2026SP
		Post-Project	Pre-Project		
1	FLT_01_CARTRCO4_RATLIFF4_138kV_3PH	Stable		Stable	Stable
2	FLT_02_CARTRCO4_POOLVIL4_138kV_3PH	Stable		Stable	Stable
3	FLT_03_CARTRCO4_SUNNYSD4_138kV_3PH	Stable		Stable	Stable
4	FLT_04_RATLIFF4_PRARPNT4_138kV_3PH	Stable		Stable	Stable
5	FLT_05_RATLIFF4_XF_138_69kV_3PH	Stable		Stable	Stable
6	FLT_06_POOLVIL4_FOX4_138kV_3PH	Stable		Stable	Stable
7	FLT_07_FOX4_DUNDEE4_138kV_3PH	Stable		Stable	Stable
8	FLT_08_DUNDEE4_HLTNTAP4_138kV_3PH	Stable		Stable	Stable
9	FLT_09_HLTNTAP4_DILLARD4_138kV_3PH	Stable		Stable	Stable
10	FLT_10_HLTNTAP4_XF_138_69kV_3PH	Stable		Stable	Stable
11	FLT_11_DILLARD4_WOLFCRK4_138kV_3PH	Stable		Stable	Stable
12	FLT_12_WOLFCRK4_CHEEKTP4_138kV_3PH	Stable		Stable	Stable
13	FLT_13_CHEEKTP4_LONEGRV4_138kV_3PH	Stable		Stable	Stable
14	FLT_14_SUNNYSD4_LONEGRV4_138kV_3PH	Stable		Stable	Stable
15	FLT_15_SUNNYSD4_UNIROY4_138kV_3PH	Stable		Stable	Stable
16	FLT_16_SUNNYSD4_ROCKYPT4_138kV_3PH	Stable		Stable	Stable
17	FLT_17_SUNNYSD7_XF2_345_138kV_3PH	Stable		Stable	Stable
18	FLT_18_SUNNYSD7_XF3_345_138kV_3PH	Stable		Stable	Stable
19	FLT_19_SUNNYSD7_TERRYRD7_345kV_3PH	Stable		Stable	Stable
20	FLT_20_SUNNYSD7_JOHNCO7_345kV_3PH	Stable		Stable	Stable
21	FLT_21_SUNNYSD7_G1663TAP_345kV_3PH	Stable		Stable	Stable
22	FLT_22_PAOLI-4_SEMINOL4_138kV_3PH	Stable		Stable	Stable
23	FLT_23_PAOLI-4_CHIGLEY4_138kV_3PH	Stable		Stable	Stable
24	FLT_24_PAOLI-4_WLNUTCK4_138kV_3PH	Stable		Stable	Stable
25	FLT_25_PAOLI-4_XF_138_69kV_3PH	Stable		Stable	Stable
26	FLT_26_CARTER4_HONEYCK4_13kV_3PH	Stable		Stable	Stable
27	FLT_27_CARTER4_CHIKSAW4_138kV_3PH	Stable		Stable	Stable

Cont. No	Contingency Name	2017WP		2018SP	2026SP
		Post-Project	Pre-Project		
28	FLT_28_CARTER4_ARDWEST4_138kV_3PH	Stable		Stable	Stable
29	FLT_29_ROCKYPT4_SPRNDAL4_138kV_3PH	Stable		Stable	Stable
30	FLT_30_ROCKYPT4_XF_138_69kV_3PH	Stable		Stable	Stable
31	FLT_31_JOHNCO7_PITTSB-7_345kV_3PH	Stable		Stable	Stable
32	FLT_32_JOHNCO7_XF_345_138kV_3PH	Stable		Stable	Stable
33	FLT_33_TERRYRD7_LES7_345kV_3PH	Network Not Converged	Network Not Converged	Stable	Stable
34	FLT_34_LES7_OKU7_345kV_3PH	Network Not Converged	Network Not Converged	Stable	Stable
35	FLT_35_LES7_G1691TAP_345kV_3PH	Network Not Converged	Network Not Converged	Stable	Stable
36	FLT_36_LES7_XF4_345_138kV_3PH	Network Not Converged	Network Not Converged	Stable	Stable
37	FLT_37_LES7_XF5_345_138kV_3PH	Network Not Converged	Network Not Converged	Stable	Stable
38	FLT_38_HUGO7_VALIANT7_345kV_3PH	Stable		Stable	Stable
39	FLT_39_HUGO7_G1663TAP_345kV_3PH	Stable		Stable	Stable
40	FLT_40_HUGO7_XF_345_138kV_3PH	Stable		Stable	Stable
41	FLT_41_CARTRCO4_138kV_SB	Stable		Stable	Stable
42	FLT_43_RATLIFF4_138kV_SB	Stable		Stable	Stable
43	FLT_44_HLTNTAP4_138kV_SB	Stable		Stable	Stable
44	FLT_45_SUNNYSD4_138kV_SB	Stable		Stable	Stable
45	FLT_46_SUNNYSD4_138kV_SB	Stable		Stable	Stable
46	FLT_47_SUNNYSD4_138kV_SB	Stable		Stable	Stable
47	FLT_48_SUNNYSD7_345KV_SB	Stable		Stable	Stable
48	FLT_49_SUNNYSD7_345KV_SB	Stable		Stable	Stable
49	FLT_50_SUNNYSD7_345KV_SB	Stable		Stable	Stable
50	FLT_51_SUNNYSD7_345KV_SB	Stable		Stable	Stable
51	FLT_52_SUNNYSD7_345KV_SB	Stable		Stable	Stable
52	FLT_53_JOHNCO7_345KV_SB	Stable		Stable	Stable
53	FLT_54_JOHNCO7_345KV_SB	Stable		Stable	Stable
54	FLT_55_JOHNCO7_345KV_SB	Stable		Stable	Stable
55	FLT_56_LES7_345KV_SB	Network Not Converged	Network Not Converged	Stable	Stable

Cont. No	Contingency Name	2017WP		2018SP	2026SP
		Post-Project	Pre-Project		
56	FLT_57_LES7_345KV_SB	Network Not Converged	Network Not Converged	Stable	Stable
57	FLT_58_LES7_345KV_SB	Network Not Converged	Network Not Converged	Stable	Stable
58	FLT_59_LES7_345KV_SB	Network Not Converged	Network Not Converged	Stable	Stable
59	FLT_60_CARTRCO4_RATLIFF4_138kV_3PH_PO1	Stable		Stable	Stable
60	FLT_61_CARTRCO4_POOLVIL4_138kV_3PH_PO1	Stable		Stable	Stable
61	FLT_62_SUNNYSD4_LONEGRV4_138kV_3PH_PO1	Stable		Stable	Stable
62	FLT_63_CARTRCO4_RATLIFF4_138kV_3PH_PO2	Stable		Stable	Stable
63	FLT_64_CARTRCO4_SUNNYSD4_138kV_3PH_PO2	Stable		Stable	Stable
64	FLT_65_CARTRCO4_POOLVIL4_138kV_3PH_PO3	Stable		Stable	Stable
65	FLT_66_CARTRCO4_SUNNYSD4_138kV_3PH_PO3	Stable		Stable	Stable
66	FLT_67_SUNNYSD7_JOHNCO7_345kV_3PH_PO4	Stable		Stable	Stable
67	FLT_68_SUNNYSD7_G1663TAP_345kV_3PH_PO4	Stable		Stable	Stable
68	FLT_69_SUNNYSD7_TERRYRD7_345kV_3PH_PO4	Stable		Stable	Stable
69	FLT_70_LES7_OKU7_345kV_3PH_PO5	Network Not Converged	Network Not Converged	Stable	Stable
70	FLT_71_LES7_G16091TAP_345kV_3PH_PO5	Network Not Converged	Network Not Converged	Stable	Stable
71	FLT_72_LES7_XF4_345_138kV_3PH_PO5	Network Not Converged	Network Not Converged	Stable	Stable
72	FLT_73_HUGO7_VALIANT7_345kV_3PH_PO6	Stable		Stable	Stable
73	FLT_74_HUGO7_XF_345_138kV_3PH_PO6	Stable		Stable	Stable
74	FLT_75_JOHNCO7_SUNNYSD7_345kV_3PH_PO7	Stable		Stable	Stable
75	FLT_76_JOHNCO7_XF_345_138kV_3PH_PO7	Stable		Stable	Stable

4.5 Modeling Considerations with the GEN-2017-027 and Origin Wind Projects

Vestas indicated that special considerations are needed when modeling the GEN-2017-027 and Origin Wind projects in the power flow cases used in the transient stability analysis. In particular, the following requirements should be met:

1. Vestas tuned the GEN-2017-027 and Origin Wind control parameters assuming that the POI bus voltage is at 1.03 pu under pre-fault conditions. Therefore, the POI bus voltage needs to be adjusted to at around 1.03 pu under pre-fault conditions; this can be achieved by adjusting the shunt capacitors at other 138 kV substations in the electrical vicinity of Carter County and/or by switching in one or more steps of 34.5 kV shunt capacitor banks within the GEN-2017-027 wind farm. The LTC tap of the 138/34.5 kV auto transformer at GEN-2017-017 may need be adjusted to maintain wind farm voltages within normal operational limits.
2. All aggregated wind turbine generators within the GEN-2017-027 and Origin Wind projects should be modeled so as to regulate voltages at their respective generator terminal buses to 1.0 pu.
3. The power plant controller (PPC) bus should be modeled at the bus that is connected to the high-side of the main power transformer (MPT) through a zero-impedance branch.
4. The reactive power output (Qgen) of each aggregated wind turbine generator in each wind farm needs to be configured such that the Qgen of all generators is the same when expressed in per unit on wind turbine generator Pmax base. Vestas indicated that this requirement is necessitated by the model code being identical to the actual PPC control logic and this is how the PPC dispatcher works. Without this, there will not be a flat start as the PPC will first align the Qgen to the same pu for all machines.

The power flow setup for the GEN-2017-027 and Origin Wind projects in the 2017 Winter Peak case is illustrated below in Figure 4-8. The power flow setup for the 2018 Summer Peak and 2026 Summer Peak cases are similar.

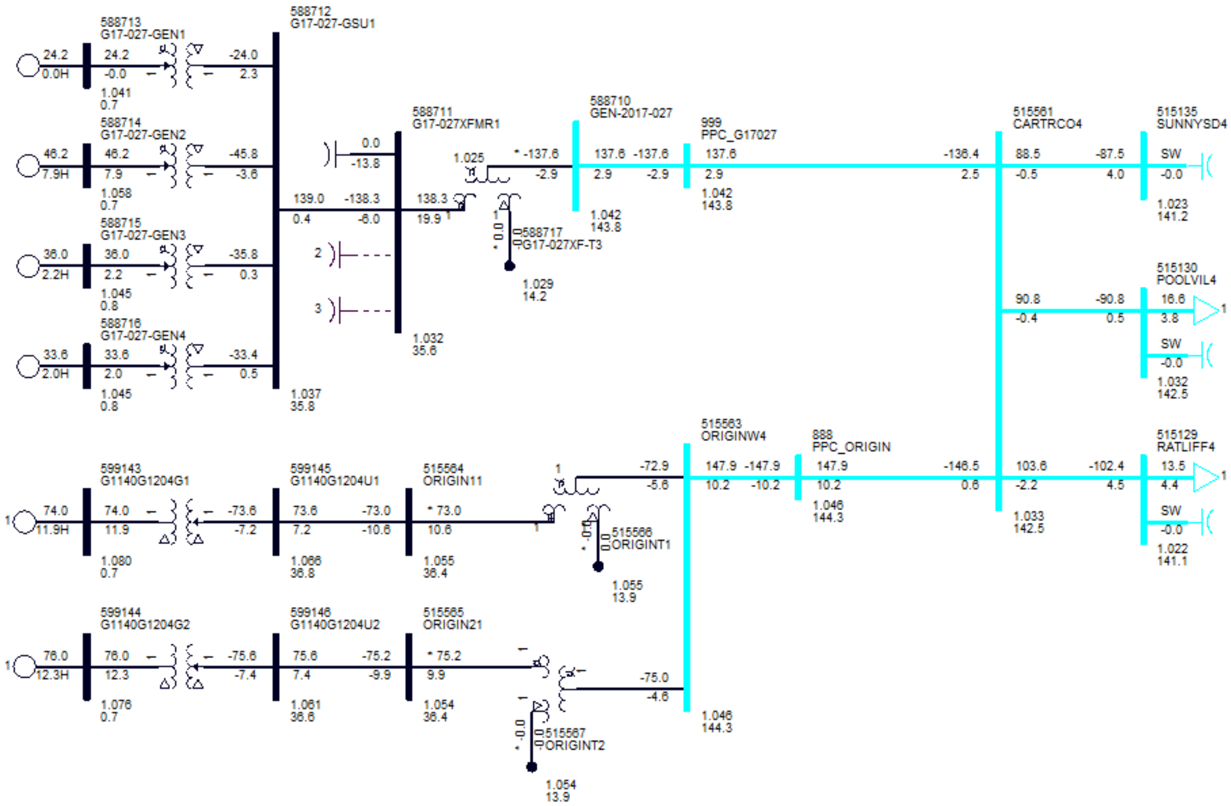


Figure 4-8: Power Flow Case Setup for Stability Analysis (2017WP)

5 Short Circuit Analysis

Short circuit analysis was performed on the 2026 Summer Peak (2026SP) Stability Analysis power flow cases using the PSS/E ASCC program. It should be noted that the stability analysis cases do not have a complete set of sequence data; therefore only three-phase symmetrical fault current levels are calculated.

5.1 Methodology

Since the Stability Analysis power flow model does not contain complete negative and zero sequence data, only three-phase symmetrical fault current levels were calculated for each bus at 69 kV or above within 5 buses of the POI. Fault current calculation was performed both without and with GEN-2017-027 in-service. The increase in fault current at each bus was also calculated.

The "Automatic Sequence Fault Calculation (ASCC)" fault analysis module of PSS/E was used with the parameters listed in Appendix F of the Study Scope.

5.2 Results

The results of the short circuit analysis for the 2026SP model are summarized in Table 5-1, which is tabulated in the descending order of %Change. The maximum increase in fault current is about 10.27%, 0.84 kA at the Carter County 138 kV. The detailed results of the short-circuit analysis are provided in Appendix E.

Table 5-1: 2026SP Case Short Circuit Results

Bus Number	Bus Name	kV	THREE PHASE FAULT Current (Amp)			
			Pre-Case	Post-Case	Amp Change	%Change
515561	CARTRCO4	138	8148.4	8985.4	837.0	10.27
515130	POOLVIL4	138	7975.0	8762.1	787.1	9.87
515131	FOX 4	138	6599.7	7025.8	426.1	6.46
515129	RATLIFF4	138	6352.9	6718.5	365.6	5.75
515132	DUNDEE 4	138	6138.8	6372.9	234.1	3.81
515563	ORIGINW4	138	5049.5	5237.9	188.4	3.73
515141	HLTNTAP4	138	6457.0	6669.5	212.5	3.29
515134	PRARPNT4	138	5329.0	5486.0	157.0	2.95
515142	DILLARD4	138	7474.9	7666.6	191.7	2.56
515135	SUNNYSD4	138	17780.5	18216.7	436.2	2.45
515143	WOLFCRK4	138	9342.9	9555.1	212.2	2.27
515144	LONEGRV4	138	12863.2	13151.7	288.5	2.24
515128	RATLIFF2	69	5002.8	5103.0	100.2	2.00
515127	WLDHRST2	69	4913.1	5009.2	96.1	1.96
515805	COUTYTP2	69	4754.7	4843.8	89.1	1.87
515140	HLTNTAP2	69	5013.7	5085.0	71.3	1.42
515145	SINCPLT2	69	5008.6	5079.7	71.1	1.42
515570	MAYSVLT4	138	5724.9	5804.8	79.9	1.40
515139	HEALDTN2	69	4264.5	4318.3	53.8	1.26
515137	UNIROY 4	138	12271.4	12424.5	153.1	1.25

Bus Number	Bus Name	kV	THREE PHASE FAULT Current (Amp)			
			Pre-Case	Post-Case	Amp Change	%Change
515372	ARDWEST4	138	12124.5	12269.2	144.7	1.19
515124	MAYSVIL4	138	6095.4	6167.3	71.9	1.18
515136	SUNNYSD7	345	10765.8	10888.0	122.2	1.14
515146	SINCLAR2	69	3822.2	3862.5	40.3	1.05
515138	CARTER 4	138	12326.5	12444.3	117.8	0.96
515100	PAOLI- 4	138	10213.7	10272.1	58.4	0.57
515643	HONEYCK4	138	8995.6	9031.8	36.2	0.40
560088	G16-063-TAP	345	7471.0	7498.0	27.0	0.36
511568	TERRYRD7	345	9882.1	9913.3	31.2	0.32
515114	CHIGLEY4	138	8081.7	8106.2	24.5	0.30
515099	PALIOGE2	69	8051.4	8066.4	15.0	0.19
511571	RUSHSPR7	345	6341.7	6353.0	11.3	0.18
515097	WLNUTCK4	138	9203.5	9218.8	15.3	0.17
510907	PITTSB-7	345	13567.0	13588.7	21.7	0.16
511468	L.E.S.-7	345	13027.3	13045.4	18.1	0.14
521157	HUGO 7	345	11053.3	11066.0	12.7	0.11
515044	SEMINOL4	138	40005.1	40047.8	42.7	0.11
510911	VALIANT7	345	13113.1	13125.3	12.2	0.09
520948	HUGO PP4	138	22242.1	22255.8	13.7	0.06
511467	L.E.S.-4	138	24443.7	24458.6	14.9	0.06

6 Reactive Compensation Analysis

Reactive compensation analysis, also known as the low-wind/no-wind condition analysis, is required by SPP to determine the amount of charging current provided by the interconnection facilities of each Generation Request and the amount of shunt reactive compensation, located at the low-voltage side (e.g. 34.5kV bus) of the collector substation bus(es) that will be required to offset the capacitive charging effects during reduced generation conditions (unsuitable wind speeds, unsuitable solar irradiance, insufficient state of charge, idle conditions, curtailment, etc.) at the generation site.

6.1 Study Methodology

As per the IASIS Scope, the reactive compensation analysis is performed on 2026 Summer Peak Stability Analysis power flow case.

The GEN-2017-027 aggregated generators and the 13 MVAr shunt capacitor were turned off in the base case as shown in Figure 6-1. The resulting reactive power injection into the transmission network comes from the capacitance of the project's transmission line and collector cables. This reactive power injection is measured at the POI. Shunt reactors are then added and tested at the project substation 34.5 kV bus to bring the MVAr flow into the POI to approximately zero.

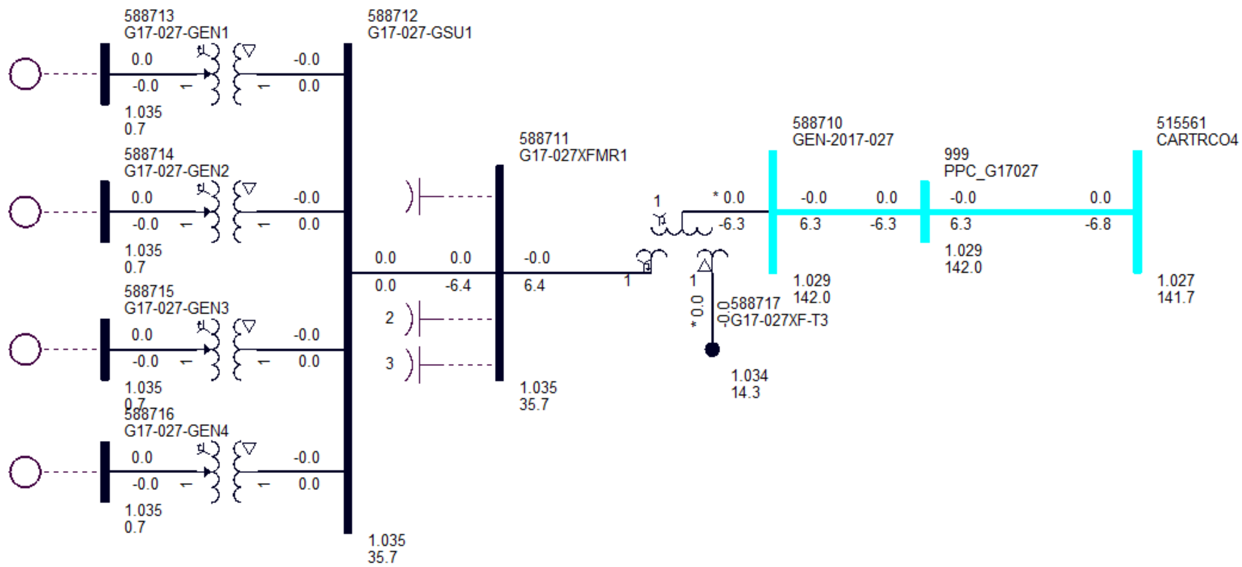


Figure 6-1: GEN-2017-027 with Generation OFF and No Shunt Reactor

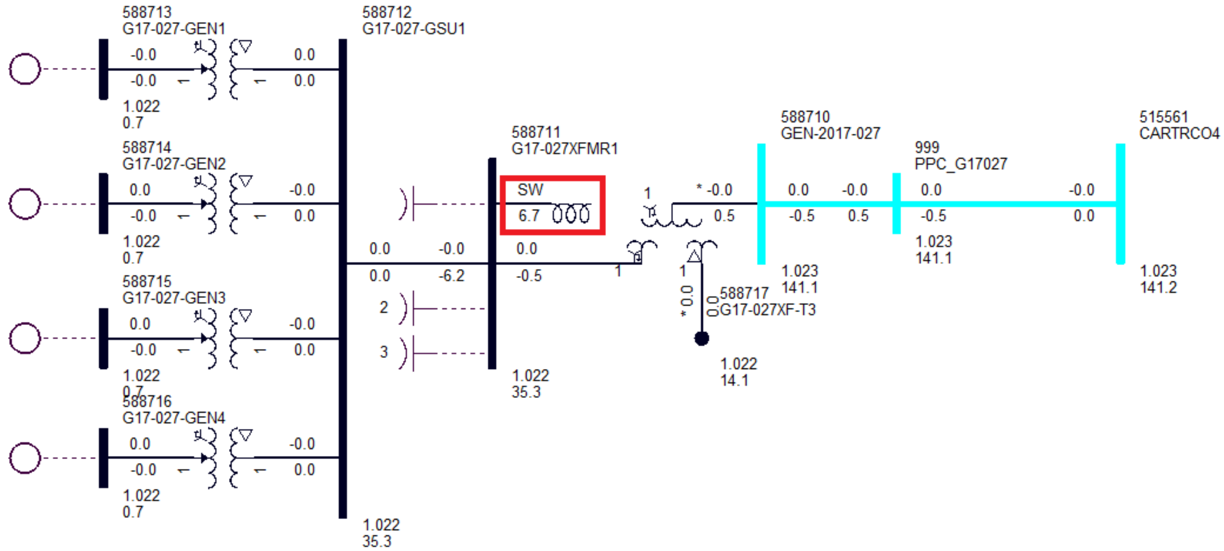


Figure 6-2: GEN-2017-027 with Generation OFF and Shunt Reactor

6.2 Results

The results from the reactive compensation analysis showed that the GEN-2017-027 project requires a 6.7 MVAr shunt reactor (approx.) at the project substation, to reduce the POI MVAr to zero. Figure 6-2 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.

7 Conclusions

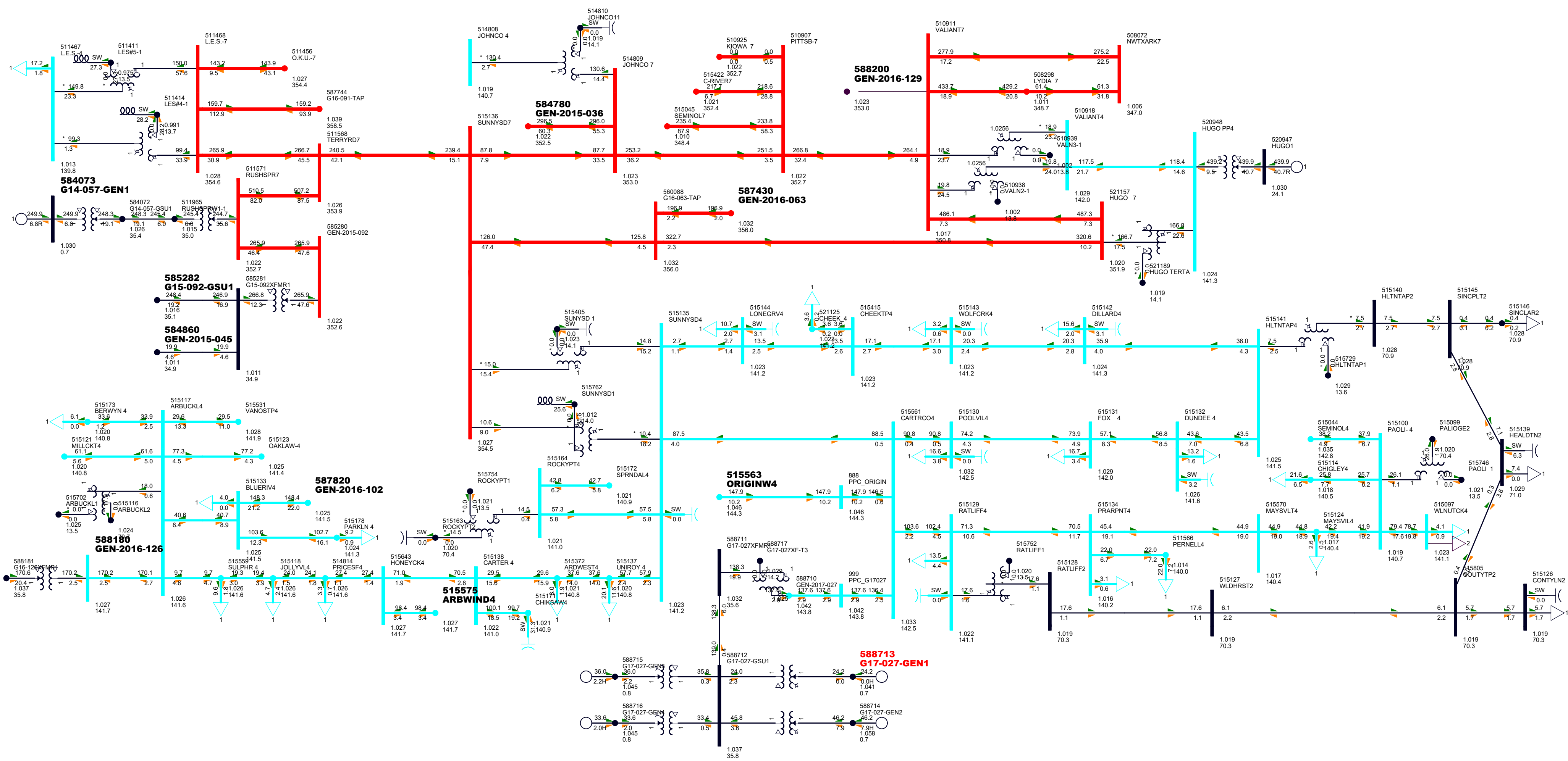
Enel Green Power (the Interconnection Customer) has requested the Interim Availability System Impact Study under the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT) for interconnection request GEN-2017-027 at the Carter County 138 kV substation in the Oklahoma Gas and Electric Company (OGE) service territory. GEN-2017-027 has requested 140 MW of wind generation be interconnected with ERIS and NRIS, with a proposed in-service date on or around December 2021.

The results from this IASIS are summarized below:

- Power flow analysis results indicate no thermal or voltage constraints that are attributed to GEN-2017-027 that need to be mitigated.
- Transient stability analysis indicate no angular instability or transient voltage response constraints attributed to GEN-2017-027. GEN-2017-027 was found to be in compliance with FERC Order 661-A and NERC-PRC-024.
- Short circuit analysis found that the maximum increase in fault current is about 10.27%, 0.84 kA at the point of interconnection.
- Reactive compensation analysis determined that a 6.7 MVAr shunt reactor (approx.) at the 34.5 kV side of project's main substation is needed to reduce the POI MVAr to zero during low/no wind conditions.

Appendix A Slider Diagrams

Diagram created using
'C:\myProjects\TWE Rockhaven Study IASIS\05_Stability\MDWG16_DIS1602_G14\MDWG16-17W_DIS1602_DP2\lf\MDWG16-17W_DIS1602_G14_G17-027_DP2.sav'
'C:\myProjects\TWE Rockhaven Study IASIS\05_Stability\GEN-2017-027-slider-stability-DPP2.sld'



Appendix B GEN–2017–027 Data

B.1 Power Flow Data Submitted in 2017

```
--------------------------------------------------------------------------------

2017 ITPNT FINAL WITH 2015 SERIES MMWG FINAL                           BUS DATA
 26SPGEN1727---TC GROUP00NR SCENARIO0
                                       S H U N T S                          X--- NORMAL --
X  X- EMERGENCY -X
   BUS# X-- NAME --X BASKV CODE LOADS FIXED SWITCHED  VOLT   ANGLE AREA ZONE OWNER   VMAX    VMIN
VMAX    VMIN
 588710 GEN-2017-027138.00   1     0     0      0    1.01006   -8.4  524  567  524  1.10000
0.90000  1.10000 0.90000
 588711 G17-027XFMR134.500   1     0     0      0    1.00719    0.2  524  567  524  1.10000
0.90000  1.10000 0.90000
 588712 G17-027-GSU134.500   1     0     0      0    1.00719    0.2  524  567  524  1.10000
0.90000  1.10000 0.90000
 588713 G17-027-GEN10.6900   2     0     0      0    1.02000    4.3  524  567  524  1.10000
0.90000  1.10000 0.90000

--------------------------------------------------------------------------------

2017 ITPNT FINAL WITH 2015 SERIES MMWG FINAL                        BRANCH DATA
 26SPGEN1727---TC GROUP00NR SCENARIO0
 X------ FROM BUS -------X  X------- TO BUS --------X                                Z S
   BUS# X-- NAME --X BASKV    BUS# X-- NAME --X BASKV CKT   LINE R    LINE X  CHRGING I T  RATEA
RATEB  RATEC LENGTH OWNR FRACT OWNR FRACT
 515561 CARTRCO4    138.00  588710 GEN-2017-027138.00* 1   0.00000  0.00010  0.00000 Z 1    0.0
0.0    0.0    6.3  524 1.000
 588711 G17-027XFMR134.500  588712 G17-027-GSU134.500* 1   0.00000  0.00010  0.00000 Z 1    0.0
0.0    0.0    0.0  524 1.000

--------------------------------------------------------------------------------

2017 ITPNT FINAL WITH 2015 SERIES MMWG FINAL                          GENERATOR
 26SPGEN1727---TC GROUP00NR SCENARIO0                                  UNIT DATA
   BUS# X-- NAME --X BASKV CD ID ST  PGEN   QGEN   QMAX   QMIN   PMAX   PMIN  OWN FRACT  OWN
FRACT  MBASE  Z S O R C E    X T R A N    GENTAP WMOD  WPF
 588713 G17-027-GEN10.6900  2 1  1  140.0   15.2   46.0  -46.0  140.0    0.0  524 1.000
100.0 0.0000 1.0000                     2  0.9500

--------------------------------------------------------------------------------

2017 ITPNT FINAL WITH 2015 SERIES MMWG FINAL                   2 WINDING XFRMER
 26SPGEN1727---TC GROUP00NR SCENARIO0                            IMPEDANCE DATA
 X------ FROM BUS -------X X------- TO BUS --------X        XFRMER    S W M C C      SPECIFIED
MAGNETIZING Y        TBL CORRECTED
   BUS# X-- NAME --X BASKV   BUS# X-- NAME --X BASKV CKT X-- NAME --X T 1 T Z M    R 1-2    X 1-2
SBAS1-2    MAG1     MAG2  TBL  R 1-2    X 1-2
 588710 GEN-2017-027138.00 588711 G17-027XFMR134.500  1              1 T T 2 1  0.00208  0.10598
96.0  0.00000  0.00000  0
 588712 G17-027-GSU134.500 588713 G17-027-GEN10.6900  1              1 T T 2 1  0.00800  0.07759
147.0  0.00000  0.00000  0

--------------------------------------------------------------------------------

2017 ITPNT FINAL WITH 2015 SERIES MMWG FINAL                   2 WINDING XFRMER
 26SPGEN1727---TC GROUP00NR SCENARIO0                              WINDING DATA
 X------ FROM BUS -------X X------- TO BUS --------X     C
   BUS# X-- NAME --X BASKV   BUS# X-- NAME --X BASKV CKT W  WINDV1  NOMV1  ANGLE  WINDV2  NOMV2
RATEA  RATEB  RATEC OWNR FRACT OWNR FRACT VECTOR GROUP
 588710 GEN-2017-027138.00 588711 G17-027XFMR134.500  1  1 1.00000 0.0000    0.0 1.00000 0.0000
160.0  160.0    0.0  524 1.000
 588712 G17-027-GSU134.500 588713 G17-027-GEN10.6900  1  1 1.00000 0.0000    0.0 1.00000 0.0000
147.0  147.0    0.0  524 1.000
```

B.2 Power Flow Data Submitted in 2021 at Decision Point 2

```
--------------------------------------------------------------------------------

2017 ITPNT FINAL WITH 2015 SERIES MMWG FINAL                          BUS DATA
 26SPGEN1727---TC GROUP14ALL SCENARIO0
                                       S H U N T S                                X--- NORMAL --
X  X- EMERGENCY -X
   BUS# X-- NAME --X BASKV CODE LOADS FIXED SWITCHED  VOLT   ANGLE AREA ZONE OWNER   VMAX    VMIN
VMAX    VMIN
 588710 GEN-2017-027138.00  1    0     0      0    1.01348   3.8  524  567  524  1.10000
0.90000  1.10000 0.90000
 588711 G17-027XFMR134.500  1    0     3      0    1.01375  10.9  524  567  524  1.10000
0.90000  1.10000 0.90000
 588712 G17-027-GSU134.500  1    0     0      0    1.01837  11.3  524  567  524  1.10000
0.90000  1.10000 0.90000
 588713 G17-027-GEN10.6900  2    0     0      0    1.02000  17.0  524  567  524  1.10000
0.90000  1.10000 0.90000
 588714 G17-027-GEN20.6900  2    0     0      0    1.02000  17.0  524  567  524  1.10000
0.90000  1.10000 0.90000
 588715 G17-027-GEN30.7200  2    0     0      0    1.02000  15.5  524  567  524  1.10000
0.90000  1.10000 0.90000
 588716 G17-027-GEN40.7200  2    0     0      0    1.02000  15.7  524  567  524  1.10000
0.90000  1.10000 0.90000
 588717 G17-027XF-T313.800  2    0     0      0    1.01271   9.9  524  567  524  1.10000
0.90000  1.10000 0.90000

--------------------------------------------------------------------------------

 2017 ITPNT FINAL WITH 2015 SERIES MMWG FINAL                         GENERATING
 26SPGEN1727---TC GROUP14ALL SCENARIO0                                PLANT DATA
                                                                                  X----- REMOTE
BUS ------X
   BUS# X-- NAME --X BASKV COD MCNS PGEN   QGEN   QMAX   QMIN VSCHED  VACT.  PCT Q   BUS# X--
NAME --X BASKV
 588713 G17-027-GEN10.6900  2   1   24.2   -0.6    0.0   -5.5 1.0200 1.0200  100.0
 588714 G17-027-GEN20.6900  2   1   46.2   -1.2   15.2  -15.2 1.0200 1.0200  100.0
 588715 G17-027-GEN30.7200  2   1   36.0   -0.8   18.4  -14.2 1.0200 1.0200  100.0
 588716 G17-027-GEN40.7200  2   1   33.6   -0.7   16.0  -12.0 1.0200 1.0200  100.0

--------------------------------------------------------------------------------

     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS(R)E     TUE, JUN 29 2021  11:14
 2017 ITPNT FINAL WITH 2015 SERIES MMWG FINAL                          GENERATOR
 26SPGEN1727---TC GROUP14ALL SCENARIO0                                 UNIT DATA
   BUS# X-- NAME --X BASKV CD ID ST  PGEN   QGEN   QMAX   QMIN   PMAX   PMIN  OWN FRACT  OWN
FRACT  MBASE  Z S O R C E    X T R A N   GENTAP WMOD  WPF
 588713 G17-027-GEN10.6900  2 1  1   24.2   -0.6    0.0   -5.5   24.2    0.0  524 1.000
24.2 0.0200 0.2290                        1  1.0000
 588714 G17-027-GEN20.6900  2 1  1   46.2   -1.2   15.2  -15.2   46.2    0.0  524 1.000
46.2 0.0200 0.2290                        1  1.0000
 588715 G17-027-GEN30.7200  2 1  1   36.0   -0.8   18.4  -14.2   36.0    0.0  524 1.000
36.0 0.6944 0.4544                        1  1.0000
 588716 G17-027-GEN40.7200  2 1  1   33.6   -0.7   16.0  -12.0   33.6    0.0  524 1.000
33.6 0.6944 0.4544                        1  1.0000

--------------------------------------------------------------------------------

2017 ITPNT FINAL WITH 2015 SERIES MMWG FINAL                           FIXED
 26SPGEN1727---TC GROUP14ALL SCENARIO0                                SHUNT DATA
   BUS# X-- NAME --X BASKV ID CODE STAT       S H U N T
 588711 G17-027XFMR134.500 1    1    1      0.0     13.0
 588711 G17-027XFMR134.500 2    1    0      0.0     13.0
 588711 G17-027XFMR134.500 3    1    0      0.0     13.0

--------------------------------------------------------------------------------
```

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--------------------------------------------------------------------------------

2017 ITPNT FINAL WITH 2015 SERIES MMWG FINAL                        BRANCH DATA
 26SPGEN1727---TC GROUP14ALL SCENARIO0
 X------ FROM BUS -------X  X------- TO BUS --------X                                Z S
   BUS# X-- NAME --X BASKV    BUS# X-- NAME --X BASKV CKT   LINE R   LINE X  CHRGING I T  RATEA
RATEB  RATEC LENGTH OWNR FRACT OWNR FRACT
 515561 CARTRCO4    138.00  588710 GEN-2017-027138.00* 1   0.00680  0.03397  0.00474   1    0.0
0.0    0.0    8.7  524 1.000
 588711 G17-027XFMR134.500  588712 G17-027-GSU134.500* 1   0.00379  0.00430  0.05954   1    0.0
0.0    0.0    0.0  524 1.000

--------------------------------------------------------------------------------

2017 ITPNT FINAL WITH 2015 SERIES MMWG FINAL                  2 WINDING XFRMER
 26SPGEN1727---TC GROUP14ALL SCENARIO0                          IMPEDANCE DATA
 X------ FROM BUS -------X X------- TO BUS --------X        XFRMER    S W M C C      SPECIFIED
MAGNETIZING Y        TBL CORRECTED
   BUS# X-- NAME --X BASKV   BUS# X-- NAME --X BASKV CKT X-- NAME --X T 1 T Z M   R 1-2    X 1-2
SBAS1-2    MAG1     MAG2  TBL  R 1-2    X 1-2
 588712 G17-027-GSU134.500 588713 G17-027-GEN10.6900  1               1 T T 2 1  0.00879  0.09580
22.7  0.00000  0.00000  0
 588712 G17-027-GSU134.500 588714 G17-027-GEN20.6900  1               1 T T 2 1  0.00879  0.09580
43.3  0.00000  0.00000  0
 588712 G17-027-GSU134.500 588715 G17-027-GEN30.7200  1               1 T T 2 1  0.00796  0.09868
46.3  0.00000  0.00000  0
 588712 G17-027-GSU134.500 588716 G17-027-GEN40.7200  1               1 T T 2 1  0.00796  0.09868
41.2  0.00000  0.00000  0

--------------------------------------------------------------------------------

2017 ITPNT FINAL WITH 2015 SERIES MMWG FINAL                  2 WINDING XFRMER
 26SPGEN1727---TC GROUP14ALL SCENARIO0                           WINDING DATA
 X------ FROM BUS -------X X------- TO BUS --------X     C
   BUS# X-- NAME --X BASKV   BUS# X-- NAME --X BASKV CKT W  WINDV1  NOMV1  ANGLE  WINDV2  NOMV2
RATEA  RATEB  RATEC OWNR FRACT OWNR FRACT VECTOR GROUP
 588712 G17-027-GSU134.500 588713 G17-027-GEN10.6900  1  1 1.00000 0.0000    0.0 1.00000 0.0000
25.3   25.3    0.0  524 1.000
 588712 G17-027-GSU134.500 588714 G17-027-GEN20.6900  1  1 1.00000 0.0000    0.0 1.00000 0.0000
48.3   48.3    0.0  524 1.000
 588712 G17-027-GSU134.500 588715 G17-027-GEN30.7200  1  1 1.00000 0.0000    0.0 1.00000 0.0000
46.3   46.3    0.0  524 1.000
 588712 G17-027-GSU134.500 588716 G17-027-GEN40.7200  1  1 1.00000 0.0000    0.0 1.00000 0.0000
41.2   41.2    0.0  524 1.000

--------------------------------------------------------------------------------
```

```
--------------------------------------------------------------------------------

2017 ITPNT FINAL WITH 2015 SERIES MMWG FINAL                  2 WINDING XFRMER
 26SPGEN1727---TC GROUP14ALL SCENARIO0                           CONTROL DATA
 X------ FROM BUS -------X X------- TO BUS --------X     W C
X---- CONTROLLED BUS ----X CONECXN
   BUS# X-- NAME --X BASKV   BUS# X-- NAME --X BASKV CKT 1 W CN   RMAX    RMIN    VMAX    VMIN
NTPS    BUS# X-- NAME --X BASKV   ANGLE    CR      CX
 588712 G17-027-GSU134.500 588713 G17-027-GEN10.6900  1  T 1  0 1.10000 1.05000 0.95000 1.05000
5                          0.000 0.95000 0.00000
 588712 G17-027-GSU134.500 588714 G17-027-GEN20.6900  1  T 1  0 1.10000 1.05000 0.95000 1.05000
5                          0.000 0.95000 0.00000
 588712 G17-027-GSU134.500 588715 G17-027-GEN30.7200  1  T 1  0 1.10000 1.05000 0.95000 1.05000
5                          0.000 0.95000 0.00000
 588712 G17-027-GSU134.500 588716 G17-027-GEN40.7200  1  T 1  0 1.10000 1.05000 0.95000 1.05000
5                          0.000 0.95000 0.00000

--------------------------------------------------------------------------------

2017 ITPNT FINAL WITH 2015 SERIES MMWG FINAL                  3 WINDING XFRMER
 26SPGEN1727---TC GROUP14ALL SCENARIO0                           GENERAL DATA
 X- XFRMER -X X---- WINDING 1 BUS ----X X---- WINDING 2 BUS ----X X---- WINDING 3 BUS ----X     S
C C C
 X-- NAME --X   BUS# X-- NAME --X BASKV   BUS# X-- NAME --X BASKV   BUS# X-- NAME --X BASKV CKT T
W Z M OWNR FRACT OWNR FRACT VECTOR GROUP
 G1727 MAIN   588710 GEN-2017-027138.00 588711 G17-027XFMR134.500 588717 G17-027XF-T313.800   1 1
1 2 1  524 1.000

--------------------------------------------------------------------------------

2017 ITPNT FINAL WITH 2015 SERIES MMWG FINAL                  3 WINDING XFRMER
 26SPGEN1727---TC GROUP14ALL SCENARIO0                          IMPEDANCE DATA
 X- XFRMER -X S C X--------- SPECIFIED NOMINAL MEASURED IMPEDANCES AND MVA BASES ----------X X-
ACTUAL IMPEDANCES FROM IMPEDANCE CORRECTION TABLE-X
 X-- NAME --X T Z   R 1-2    X 1-2 SBAS1-2   R 2-3    X 2-3 SBAS2-3   R 3-1    X 3-1 SBAS3-1   R
1-2    X 1-2    R 2-3    X 2-3    R 3-1    X 3-1
 G1727 MAIN   1 2  0.00413  0.09991  108.0  0.00088  0.02138  108.0  0.00378  0.09142  108.0

--------------------------------------------------------------------------------

2017 ITPNT FINAL WITH 2015 SERIES MMWG FINAL                  3 WINDING XFRMER
 26SPGEN1727---TC GROUP14ALL SCENARIO0                           WINDING DATA
 X- XFRMER -X X----- WINDING BUS -----X  S C    MAGNETIZING Y   SYSTEM BASE NOM.
TBL CORRECTED   STAR POINT BUS
 X-- NAME --X   BUS# X-- NAME --X BASKV  T M    MAG1     MAG2   R WNDNG  X WNDNG  RATEA  RATEB
RATEC TBL R WNDNG  X WNDNG VOLTAGE  ANGLE
 G1727 MAIN   588710 GEN-2017-027138.00* 1 1  0.00000  0.00000  0.00325  0.07868  167.0  167.0
0.0  0                 1.01271    9.9
              588711 G17-027XFMR134.500* 1                      0.00057  0.01383  167.0  167.0
0.0  0
              588717 G17-027XF-T313.800  1                      0.00025  0.00597  167.0  167.0
0.0  0

--------------------------------------------------------------------------------

2017 ITPNT FINAL WITH 2015 SERIES MMWG FINAL                  3 WINDING XFRMER
 26SPGEN1727---TC GROUP14ALL SCENARIO0                         TAP/CONTROL DATA
 X- XFRMER -X X----- WINDING BUS -----X C
X---- CONTROLLED BUS ----X CNXTN
 X-- NAME --X   BUS# X-- NAME --X BASKV W CN  WIND V  NOM V  ANGLE   RMAX    RMIN    VMAX    VMIN
NTPS    BUS# X-- NAME --X BASKV ANGLE    CR      CX
 G1727 MAIN   588710 GEN-2017-027138.00 1  1 1.00000 138.00    0.0 1.10000 0.90000 1.10000
0.90000   33  588711 G17-027XFMR134.500   0.0
              588711 G17-027XFMR134.500    0 1.00000 34.500    0.0 1.10000 0.90000 1.10000
0.90000   33                          0.0
              588717 G17-027XF-T313.800    0 1.00000 13.800    0.0 1.10000 0.90000 1.10000
0.90000   33                          0.0
--------------------------------------------------------------------------------
```

B.3 Dynamic Data

```
/**************** Rockhaven***************************
588713,'USRMDL','1','PPCORE530V5709', 104  0  262  100  4  250,
   530101      5       7       9       999     999
   588710      999     1       0       0       0
       0       0       0       0       0       0
       0       0       588713  1       588714  1
       588715  1       588716  1       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       0       0       0       0       0       0
       1       1       1       1       21      26
       21      26      1       6
       140000  0.01    0.01    0.01     0.01   0
       0       0       0       0.001    0      0
       0       0       0       0       0       1
       1       1       1       1       1       1
       1       0       0       0       0       1
       1       1       1       1       1       1
       1       0       0       0       0       0
       0       0       0       1       1       1
       1       0       0       0       0       1
       1       1       1       0       0       0
       0       0       0       0       0       0
       1       1       1       1       1       1
       1       1       1       1       1       1
       1       1       1       0       0       0
       0       0       1       1       1       1
       1       1       1       1       1       1
       0       0       0       0       /
588713,'USRMDL','1','PPCPMM530V5709', 105  0  0  25  0  0,
        1.1    0.9     3000     0      3000    5000
       0.85    0.9     0       1       0.05    30
       0.025   0       1.15    1.1     0       0
       0       0       0.09    5000    0       5000
       10      /
```

```
588713,'USRMDL','1','PPCAPW530V5709', 106  0  0  171  0  0,
       1      0      0      1000   1000   0.027
       0.0017 0.00224 90    1000   0      0
       1      0      1.2    0      2000   2000
       1      -1.0   -0.4   -1.0   -0.4   -1.0
       -0.4   -0.2   0.0    -0.2
       0.0    0.2    0.0    0.2    0.0    1.2
       0.3    1.8    0.6    2.5    1.0    0.015
       0      100    1      0      0.1    0
       0.92   -1000  300    300    300    200
       1000   1.06   0      0      0      0.98
       0.99   1.02   1.04   1.045  0.9997 1.0003
       0      0.04   0.986  0      0      0.986
       0.986  1.038  1.038  1.038  1.04   1
       0.2    0.9997 1.0003 0      0      40
       40     40     40     40     40     10
       0      -0.2   0.0    0.0    -0.2   0.0
       0.0    0.2    0.0    0.0    0.2    0.0
       0.0    0      0      10     0.02   0
       0      0      140000 1      1      1
       1      1      0      0      0      0
       1.04   1.04   1      6150   0      2
       100    1      1      1      1      0
       0      0      0      0      0      0
       0      0      0      0      0      0
       0      0      0      0      0      0
       0      0      0      0      0      0
       0      0.9    0      0      0      1
       0.3    0.02   0.1    0.3    0      0
       0      0      0      0      0      /
588713,'USRMDL','1','PPCRPW530V5709', 107  0  0  87  0  0,
       4      0      0      0      49615  46899
       5      0      0      0      3      0
       49615  46899  0      0.95   0.95   1
       4      0      0.001  1.5    1      1.06
       0.15   0.001  0.04   0.04   46000  0.5
       0.5    0.001  0.001  0.204  0      5000
       5000   0.2    0.4    0.6    0.8    0.6
       0.7    0.8    0.9    0.9    -0.4   -0.2
       0.2    0.4    0.4    0.1    0.2    0.3
       0.4    0.008  0.05   -1000  -1000  1000
       1000   2000   1000   1000   1000   1000
       0      0.005  1.1    0.9    1      1
       100    0      0      0      0      0
       0      0      0      0      0      750
       0      0.01   0.01   /
/
/
588713,'USRMDL','1','VC20045709', 101 1 6 31 10 50, 47202004 86 19 0 5 7
5      7.09   -12345 1      2200   1      1
0.85   1.15   0.8    1.2    0.001  0      36
1      1      24195  24297  22133  24273  24295
24302  24064  24301  24301  24298  22793  24297
24263  -12345 -12345/
/
/
588714,'USRMDL','1','VC20045709', 101 1 6 31 10 50, 47202004 86 19 0 5 7
5      7.09   -12345 1      2200   1      1
0.85   1.15   0.8    1.2    0.001  0      36
1      1      24213  24297  22133  24273  24294
24297  24064  24301  24312  24298  22793  24297
24263  -12345 -12345/
/
/
588715,'USRMDL','1','CP20065709', 101 1 6 32 10 50, 37202006 86 19 0 5 7
5      7.09   -12345 1      4000   1      2
0      1      0.8    0.85   1.2    1.15   1
37     0      0.001  24187  24302  20813  24273
24302  24296  24064  24301  24301  24298   22793
24299  24224  -12345 -12345/
/
/
```

```
588716,'USRMDL','1','CP20065709', 101 1 6 32 10 50, 37202006 86 19 0 5 7
5       7.09    -12345 1      4200    1       2
0       1       0.8    0.85   1.2     1.15    1
25      0       0.001  24187  24302   20101   24273
24302   24296   24064  24301  24312   24298   22793
24299   24224   -12345 -12345/
/
/********************* End of Plant Data *********************************************
```

Appendix C Origin Wind Project Data

C.1 Existing Dynamic Data

```
/ Vestas 2.0 MW V100 VCSS (VestasWT_7_6_0_PSSE32.lib)
/
599143 'USRMDL' '1'  'VWCOR6' 1 1 2 45 23 104 1 0
 2000.0000 690.0000 1514.6603 700.0000 1.5625 0.9676 0.0232
 1.9807 8.3333 1.9807 8.3333 30.0000 0.2000 1.2000
 0.1000 0.0012 0.9925 0.0474 1.6118 0.0000 351.8584
 313.4245 0.0300 0.0000 0.0300 0.3000 0.0000 1.0000
 0.3183 4.9736 2812227.1900 43.2960 90.0120 600000.0000 3.0000
 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.0000/
0 'USRMDL' 0 'VWVAR6' 8 0 2 0 0 30 599143 '1'  /
0 'USRMDL' 0 'VWLVR6' 8 0 3 65 10 35 599143 '1' 1
 0.9000 0.0010 0.2000 44.4555 11.1114 44.4555 44.4555
 0.5000 1.0000 1.5625 0.9676 1.2000 0.5000 690.0000
1514.6603 0.3500 0.0500 0.2500 0.0200 3.0000 4.0000
 9999.0000 0.0232 0.9000 0.9000 0.0500 0.0000 0.0100
 0.0000 2.0000 0.0000 1.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 /
0 'USRMDL' 0 'VWPWR6' 8 0 3 30 7 10 599143 '1' 1
 1.0000 0.5000 -0.5000 0.6988 0.8844 0.9800 0.9600
 0.2000 0.2000 1.3000 0.0500 0.5000 0.5000 0.1000
 0.1000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 /
0 'USRMDL' 0 'VWMEC6' 8 0 2 10 8 0 599143 '1'
 2000.0000 351.8584 5684.1051 569.9822 106.4850 7976.7600 50.7400
 0.0000 0.0000 0.0000 /
0 'USRMDL' 0 'VWMEA6' 8 0 2 10 8 5 599143 '1'
 0.1000 0.1000 0.1000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.0000/
0 'USRMDL' 0 'VWVPR6' 0 2 7 30 0 18 599143 '1'  1 1 0 0 0
 0.8500 11.0000 0.8500 11.0000 0.9000 60.0000 1.1000
 60.0000 1.1500 2.0000 1.2000 0.0800 1.2500 0.0050
```

```
 1.2500 0.0050 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.1500 0.8000 2.7000 0.8500 3.5000
 0.9000 5.0000 /
0 'USRMDL' 0 'VWFPR6' 0 2 3 12 0 7 599143 '1'  0
 56.4000 0.2000 56.4000 0.2000 56.4000 0.2000 63.6000
 0.2000 63.6000 0.2000 63.6000 0.2000 /
/
599144 'USRMDL' '1'  'VWCOR6' 1 1 2 45 23 104 1 0
 2000.0000 690.0000 1514.6603 700.0000 1.5625 0.9676 0.0232
 1.9807 8.3333 1.9807 8.3333 30.0000 0.2000 1.2000
 0.1000 0.0012 0.9925 0.0474 1.6118 0.0000 351.8584
 313.4245 0.0300 0.0000 0.0300 0.3000 0.0000 1.0000
 0.3183 4.9736 2812227.1900 43.2960 90.0120 600000.0000 3.0000
 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.0000/
0 'USRMDL' 0 'VWVAR6' 8 0 2 0 0 30 599144 '1'  /
0 'USRMDL' 0 'VWLVR6' 8 0 3 65 10 35 599144 '1' 1
 0.9000 0.0010 0.2000 44.4555 11.1114 44.4555 44.4555
 0.5000 1.0000 1.5625 0.9676 1.2000 0.5000 690.0000
1514.6603 0.3500 0.0500 0.2500 0.0200 3.0000 4.0000
 9999.0000 0.0232 0.9000 0.9000 0.0500 0.0000 0.0100
 0.0000 2.0000 0.0000 1.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 /
0 'USRMDL' 0 'VWPWR6' 8 0 3 30 7 10 599144 '1' 1
 1.0000 0.5000 -0.5000 0.6988 0.8844 0.9800 0.9600
 0.2000 0.2000 1.3000 0.0500 0.5000 0.5000 0.1000
 0.1000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 /
0 'USRMDL' 0 'VWMEC6' 8 0 2 10 8 0 599144 '1'
 2000.0000 351.8584 5684.1051 569.9822 106.4850 7976.7600 50.7400
 0.0000 0.0000 0.0000 /
0 'USRMDL' 0 'VWMEA6' 8 0 2 10 8 5 599144 '1'
 0.1000 0.1000 0.1000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.0000/
0 'USRMDL' 0 'VWVPR6' 0 2 7 30 0 18 599144 '1'  1 1 0 0 0
```

```
 0.8500 11.0000 0.8500 11.0000 0.9000 60.0000 1.1000
 60.0000 1.1500 2.0000 1.2000 0.0800 1.2500 0.0050
 1.2500 0.0050 0.0000 0.0000 0.0000 0.0000 0.0000
 0.0000 0.0000 0.1500 0.8000 2.7000 0.8500 3.5000
 0.9000 5.0000 /
0 'USRMDL' 0 'VWFPR6' 0 2 3 12 0 7 599144 '1'  0
 56.4000 0.2000 56.4000 0.2000 56.4000 0.2000 63.6000
 0.2000 63.6000 0.2000 63.6000 0.2000 /
```

C.2 Updated Dynamic Data

```
/PPCUMF (PPC Unified FrameWork Model)------------------------------------------------------------
599143,'USRMDL','1','PPCOREM3V52500', 104  0  60  8  30  200,
   323001       1000     2000     0              5          25
   888  515561  1       888    515561           1
   0    0       0       0       0               0
   0    0       0       0,      0               0
   0    0       599143 1        599144          1
   0    0       0       0       0               0
   0    0       0       0       0               0
   0    0       0       0       0               0
   0    0       0       0       0               0
   0    0       0       0       0                0,
   150000       0.01     0.01     0.01          0.01       -0.01
   0.0          0.0/
599143,'USRMDL','1','PPCPMMM3V52500', 105  0  0  24  0  0,
   1.1          0.9             3000            0.0             3000            5000
   0.85         0.9,
   0.0          1               0.05            30              0.025,
   0.0          1.15            1.10            1.0             2.0             1.1
   0.0          0.09            5000.0          0.0             3000.0/
599143,'USRMDL','1','PPCAPWM3V52500', 106  0  0  41  0  0,
   1.0          0.0             0.0             1000.00         1000.00         0.027
   0.0017       0.00224         2.0             90.0,
   1.0          4.0             4.0             2.0             0.015          -0.015
   0.5          2000.0          2000.0,
   2.0          -2.0             0.0            -0.015           10.0            0.015
   10           1.0             50              2.0             100             3.0
   100          0.015           2000            2000,
   0.0          10000.0         0.0             1.0             0.1             0./
599143,'USRMDL','1','PPCRPWM3V52500', 107  0  0  73  0  0,
```

```
  4.0              0.0            0.0            1.0            0.0            999999
  999999     5.0          0.0            0.005          0.0           3.0
  0.0        999999       999999         0.0            0.95          -0.95
  1.0        4.0          0.0            0.001          1.5           1.0
  1.06       0.15         0.001        0.04           0.04          46000
  0.5        0.5          0.001        0.001        0.204         0.67
  0.               1            5000.          100000.        0.2           0.4
  0.60       0.80         1.00           1.00           1.00          1.00
  1.0        0.00               0.1041         0.2083         0.3           0.4
  0.1        0.2                0.3            0.4            0.008         0.05
  -1000      1000         1000           1000             0             0
  0          0            0            4600           4600          2.0
  10000.0/
//******************** End of PPC&MSU and Statcom *********************************************
/
599143,'USRMDL','1','VS170952500', 101 1 7 31 10 50, 57201709 86 21 0 5 25 12
5      25     -12345        1      2000   1      1
0.85   1.15   0.8           1.2    0.001  0      20
0      1      24201         24296  22845  24273  24298
24293  24064  24301         24301  24298  22796  24292
24553  -12345 -12345/
/
599144,'USRMDL','1','VS170952500', 101 1 7 31 10 50, 57201709 86 21 0 5 25 12
5      25     -12345        1      2000   1      1
0.85   1.15   0.8           1.2    0.001  0      20
0      1      24201         24296  22845  24273  24298
24293  24064  24301         24301  24298  22796  24292
24553  -12345 -12345/
//******************** End of WTG *********************************************
```

Appendix D List of Faults for Stability Analysis

No	Cont. Name	Description
1	FLT_01_CARTRCO4_RATLIFF4_138kV_3PH	3 phase fault on the Carter Co (515561) to Ratliff (515129) 138kV CKT 1, near Carter Co. a. Apply fault at the Carter Co 138kV bus. b. Clear fault after 7 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 7 cycles, then trip the line in (b) and remove fault.
2	FLT_02_CARTRCO4_POOLVIL4_138kV_3PH	3 phase fault on the Carter Co (515561) to Pooleville (515130) 138kV CKT 1, near Carter Co. a. Apply fault at the Carter Co 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line and all sections between Pooleville (515130) to Healdton Tap (515141). c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
3	FLT_03_CARTRCO4_SUNNYSD4_138kV_3PH	3 phase fault on the Carter Co (515561) to Sunnyside (515135) 138kV CKT 1, near Carter Co. a. Apply fault at the Carter Co 138kV bus. b. Clear fault after 7 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 7 cycles, then trip the line in (b) and remove fault.
4	FLT_04_RATLIFF4_PRARPNT4_138kV_3PH	3 phase fault on the Ratliff (515129) to Prairie Pt. (515134) 138kV CKT 1, near Ratliff. a. Apply fault at the Ratliff 138kV bus. b. Clear fault after 7 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 7 cycles, then trip the line in (b) and remove fault.
5	FLT_05_RATLIFF4_XF_138_69kV_3PH	3 phase fault on the Ratliff 138kV (515129) to 69kV (515128) to 13.2kV (515752) CKT 1, near Ratliff 138kV. a. Apply fault at the Ratliff 138kV bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
6	FLT_06_POOLVIL4_FOX4_138kV_3PH	3 phase fault on the Pooleville (515130) to Fox (515131) 138kV CKT 1, near Pooleville. a. Apply fault at the Pooleville 138kV bus. b. Clear fault after 7 cycles by tripping all sections between Carter Co (515561) to Healdton Tap (515141). c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
7	FLT_07_FOX4_DUNDEE4_138kV_3PH	3 phase fault on the Fox (515131) to Dundee (515132) 138kV CKT 1, near Fox. a. Apply fault at the Fox 138kV bus. b. Clear fault after 7 cycles by tripping all sections between Carter Co (515561) to Healdton Tap (515141). c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
8	FLT_08_DUNDEE4_HLTNTAP4_138kV_3PH	3 phase fault on the Dundee (515132) to Healdton Tap (515141) 138kV CKT 1, near Dundee. a. Apply fault at the Dundee 138kV bus. b. Clear fault after 7 cycles by tripping all sections between Carter Co (515561) to Healdton Tap (515141). c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
9	FLT_09_HLTNTAP4_DILLARD4_138kV_3PH	3 phase fault on the Healdton Tap (515141) to Dillard (515142) 138kV CKT 1, near Healdton Tap. a. Apply fault at the Healdton Tap 138kV bus. b. Clear fault after 7 cycles by tripping all sections between Lone Grove (515144) to Healdton Tap (515141).

No	Cont. Name	Description
		c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
10	FLT_10_HLTNTAP4_XF_138_69kV_3PH	3 phase fault on the Healdton Tap (515141) to 69kV (515140) to 13.2kV (515129) CKT 1, near Healdton Tap 138kV. a. Apply fault at the Healdton Tap 138kV bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
11	FLT_11_DILLARD4_WOLFCRK4_138kV_3PH	3 phase fault on the Dillard (515142) to Wolf Creek (515143) to 138kV CKT 1, near Dillard. a. Apply fault at the Dillard 138kV bus. b. Clear fault after 7 cycles by tripping all sections between Lone Grove (515144) to Healdton Tap (515141). c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
12	FLT_12_WOLFCRK4_CHEEKTP4_138kV_3PH	3 phase fault on the Wolf Creek (515143) to Cheek Tap (515415) 138kV CKT 1, near Wolf Creek. a. Apply fault at the Wolf Creek 138kV bus. b. Clear fault after 7 cycles by tripping all sections between Lone Grove (515144) to Healdton Tap (515141). c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
13	FLT_13_CHEEKTP4_LONEGRV4_138kV_3PH	3 phase fault on the Cheek Tap (515415) to Love Grove (515144) 138kV CKT 1, near Cheek Tap. a. Apply fault at the Cheek Tap 138kV bus. b. Clear fault after 7 cycles by tripping all sections between Lone Grove (515144) to Healdton Tap (515141). c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
14	FLT_14_SUNNYSD4_LONEGRV4_138kV_3PH	3 phase fault on the Sunnyside (515135) to Love Grove (515144) to 138kV CKT 1, near Sunnyside. a. Apply fault at the Sunnyside 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line and all sections between Lone Grove (515144) to Healdton Tap (515141). c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
15	FLT_15_SUNNYSD4_UNIROY4_138kV_3PH	3 phase fault on the Sunnyside (515135) to Uniroyal (515137) 138kV CKT 1, near Sunnyside. a. Apply fault at the Sunnyside 138kV bus. b. Clear fault after 7 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 7 cycles, then trip the line in (b) and remove fault.
16	FLT_16_SUNNYSD4_ROCKYPT4_138kV_3PH	3 phase fault on the Sunnyside (515135) to Rocky Point (515164) 138kV CKT 1, near Sunnyside. a. Apply fault at the Sunnyside 138kV bus. b. Clear fault after 7 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 7 cycles, then trip the line in (b) and remove fault.
17	FLT_17_SUNNYSD7_XF2_345_138kV_3PH	3 phase fault on the Sunnyside 345kV (515136) to 138kV (515135) to 13.8kV (515405) CKT 1 (XF2), near Sunnyside 345kV. a. Apply fault at the Sunnyside 345kV bus. b. Clear fault after 6 cycles by tripping the faulted transformer.
18	FLT_18_SUNNYSD7_XF3_345_138kV_3PH	3 phase fault on the Sunnyside 345kV (515136) to 138kV (515135) to 13.8kV (515762) CKT 1 (XF3), near Sunnyside 345kV. a. Apply fault at the Sunnyside 345kV bus. b. Clear fault after 6 cycles by tripping the faulted transformer.

No	Cont. Name	Description
19	FLT_19_SUNNYSD7_TERRYRD7_345kV_3PH	3 phase fault on the Sunnyside (515136) to Terry Road (511568) 345kV line CKT 1, near Sunnyside. a. Apply fault at the Sunnyside 345kV 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.
20	FLT_20_SUNNYSD7_JOHNCO7_345kV_3PH	3 phase fault on the Sunnyside (515136) to Johnson Co. (514809) 345kV CKT 1, near Sunnyside. a. Apply fault at the Sunnyside 345kV 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.
21	FLT_21_SUNNYSD7_G1663TAP_345kV_3PH	3 phase fault on the Sunnyside (515136) 345kV to G16-063-TAP (560088) 345 kV CKT 1, near Sunnyside. a. Apply fault at the Sunnyside 345kV 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.
22	FLT_22_PAOLI-4_SEMINOL4_138kV_3PH	3 phase Paoli on the Paoli (515100) to Seminole (515044) 138kV CKT 1, near Paoli. a. Apply fault at the Paoli 138kV bus. b. Clear fault after 7 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 7 cycles, then trip the line in (b) and remove fault.
23	FLT_23_PAOLI-4_CHIGLEY4_138kV_3PH	3 phase fault on the Paoli (515100) to Chigley (515114) 138kV CKT 1, near Paoli. a. Apply fault at the Paoli 138kV bus. b. Clear fault after 7 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 7 cycles, then trip the line in (b) and remove fault.
24	FLT_24_PAOLI-4_WLNUTCK4_138kV_3PH	3 phase fault on the Paoli (515100) to Walnut Creek (515097) 138kV CKT 1, near Paoli. a. Apply fault at the Paoli 138kV bus. b. Clear fault after 7 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 7 cycles, then trip the line in (b) and remove fault.
25	FLT_25_PAOLI-4_XF_138_69kV_3PH	3 phase fault on the Paoli 138kV (515100) to 69kV (515099) to 13.2kV (515746) CKT 1, near Paoli 138kV. a. Apply fault at the Paoli 138kV bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
26	FLT_26_CARTER4_HONEYCK4_13kV_3PH	3 phase fault on the Carter Tap (515138) to Honey Creek (515643) 138kV CKT 1, near Carter Tap. a. Apply fault at the Carter Tap 138kV bus. b. Clear fault after 7 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 7 cycles, then trip the line in (b) and remove fault.
27	FLT_27_CARTER4_CHIKSAW4_138kV_3PH	3 phase fault on the Carter Tap (515138) to Chickasaw (515171) 138kV CKT 1, near Carter Tap. a. Apply fault at the Carter Tap 138kV bus. b. Clear fault after 7 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 7 cycles, then trip the line in (b) and remove fault.

No	Cont. Name	Description
28	FLT_28_CARTER4_ARDWEST4_138kV_3PH	3 phase fault on the Carter Tap (515138) to Ardmore West (515372) 138kV CKT 1, near Carter Tap. a. Apply fault at the Carter Tap 138kV bus. b. Clear fault after 7 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 7 cycles, then trip the line in (b) and remove fault.
29	FLT_29_ROCKYPT4_SPRNDAL4_138kV_3PH	3 phase fault on the Rocky Point (515164) to Springdale (515172) 138kV CKT 1, near Rocky Point. a. Apply fault at the Rocky Point 138kV bus. b. Clear fault after 7 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 7 cycles, then trip the line in (b) and remove fault.
30	FLT_30_ROCKYPT4_XF_138_69kV_3PH	3 phase fault on the Rocky Point 138kV (515164) to 69kV (515163) to 13.2kV (515754) CKT 1, near Rocky Point 138kV. a. Apply fault at the Rocky Point 138kV bus. b. Clear fault after 7 cycles by tripping the faulted transformer.
31	FLT_31_JOHNCO7_PITTSB-7_345kV_3PH	3 phase fault on the Johnson Co. (514809) to Pittsburg (510907) to 345kV CKT 1, near Johnson Co. a. Apply fault at the Johnson Co. 345kV 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.
32	FLT_32_JOHNCO7_XF_345_138kV_3PH	3 phase fault on the Johnson Co. 345kV (514809) to 138kV (514808) to 13.2kV (514810) CKT 1, near Johnson Co. 345kV. a. Apply fault at the Johnson Co. 345kV bus. b. Clear fault after 6 cycles by tripping the faulted transformer.
33	FLT_33_TERRYRD7_LES7_345kV_3PH	3 phase fault on the Terry Road (511568) to Lawton Eastside (511468) 345kV line CKT 1, near Terry Road. a. Apply fault at the Terry Road 345kV 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.
34	FLT_34_LES7_OKU7_345kV_3PH	3 phase fault on the Lawton Eastside (511468) to Oklaunion (511456) 345kV line CKT 1, near Lawton Eastside. a. Apply fault at the Lawton Eastside 345kV 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.
35	FLT_35_LES7_G1691TAP_345kV_3PH	3 phase fault on the Lawton Eastside (511468) to G16-091-TAP (587744) 345kV line CKT 1, near Lawton Eastside. a. Apply fault at the Lawton Eastside 345kV 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.
36	FLT_36_LES7_XF4_345_138kV_3PH	3 phase fault on the Lawton Eastside 345kV (511468) to 138kV (511467) to 13.8kV (511414) CKT 1 (XF4), near Lawton Eastside 345kV. a. Apply fault at the Lawton Eastside 345kV bus. b. Clear fault after 6 cycles by tripping the faulted transformer.
37	FLT_37_LES7_XF5_345_138kV_3PH	3 phase fault on the Lawton Eastside 345kV (511468) to 138kV (511467) to 13.8kV (511411) CKT 1 (XF5), near Lawton Eastside 345kV. a. Apply fault at the Lawton Eastside 345kV bus. b. Clear fault after 6 cycles by tripping the faulted transformer.

No	Cont. Name	Description
38	FLT_38_HUGO7_VALIANT7_345kV_3PH	3 phase fault on the Hugo (521157) to Valiant (587744) 345kV line CKT 1, near Hugo. a. Apply fault at the Hugo 345kV 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.
39	FLT_39_HUGO7_G1663TAP_345kV_3PH	3 phase fault on the Hugo (521157) to G16-063 Tap (560088) 345kV line CKT 1, near Hugo. a. Apply fault at the Hugo 345kV 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.
40	FLT_40_HUGO7_XF_345_138kV_3PH	3 phase fault on the Hugo (521157) to 138kV (520948) to 13.8kV (521189) CKT 1, near Hugo 345kV. a. Apply fault at the Hugo 345kV bus. b. Clear fault after 6 cycles by tripping the faulted transformer.
41	FLT_41_CARTRCO4_138kV_SB	**Stuck Breaker at Carter Co. 138kV (515561)** a. Apply single phase fault at the Carter Co 138kV bus. b. Clear fault after 16 cycles by tripping the following elements: - Carter Co (515561) to Ratliff (515129) 138kV CKT 1 - Carter Co (515561) to Pooleville (515130) 138kV CKT 1 and all sections between Pooleville (515130) to Healdton Tap (515141).
43	FLT_43_RATLIFF4_138kV_SB	**Stuck Breaker at Ratliff 138kV (515129)** a. Apply single phase fault at the Ratliff 138kV bus. b. Clear fault after 16 cycles by tripping the faulted bus
44	FLT_44_HLTNTAP4_138kV_SB	**Stuck Breaker at Healdton Tap 138kV (515141)** a. Apply single phase fault at the Healdton Tap 138kV bus. b. Clear fault after 16 cycles by tripping the faulted bus
45	FLT_45_SUNNYSD4_138kV_SB	**Stuck Breaker at Sunnyside 138kV (515135)** a. Apply single phase fault at the Sunnyside 138kV bus. b. Clear fault after 16 cycles by tripping the following elements: - Sunnyside (515135) to Carter Co. (515561) 138kV CKT 1 - Sunnyside (515135) to Lone Grove (515144) 138kV CKT 1 - all sections between Lone Grove (515144) to Healdton Tap (515141)
46	FLT_46_SUNNYSD4_138kV_SB	**Stuck Breaker at Sunnyside 138kV (515135)** a. Apply single phase fault at the Sunnyside 138kV bus. b. Clear fault after 16 cycles by tripping the following elements: - Sunnyside (515135) to Uniroyal (515137) 138kV CKT 1 - Sunnyside 345kV (515136) to 138kV (515135) to 13.8kV (515405) CKT 1 (XF2)
47	FLT_47_SUNNYSD4_138kV_SB	**Stuck Breaker at Sunnyside 138kV (515135)** a. Apply single phase fault at the Sunnyside 138kV bus. b. Clear fault after 16 cycles by tripping the following elements: - Sunnyside (515135) to Rocky Point (515164) 138kV CKT 1 - Sunnyside 345kV (515136) to 138kV (515135) to 13.8kV (515762) CKT 1 (XF3)
48	FLT_48_SUNNYSD7_345KV_SB	**Stuck Breaker at Sunnyside 345kV (515136)** a. Apply single phase fault at the Sunnyside 345kV bus. b. Clear fault after 16 cycles by tripping the following elements: - Sunnyside (515136) to G16-063 Tap (560088) 345kV CKT 1. - Sunnyside 345kV (515136) to 138kV (515135) to 13.8kV (515405) CKT 1 (XF2)

No	Cont. Name	Description
49	FLT_49_SUNNYSD7_345KV_SB	**Stuck Breaker at Sunnyside 345kV (515136)** a. Apply single phase fault at the Sunnyside 345kV bus. b. Clear fault after 16 cycles by tripping the following elements: - Sunnyside (515136) to Johnson Co. (514809) 345kV CKT 1 - Sunnyside 345kV (515136) to 138kV (515135) to 13.8kV (515762) CKT 1 (XF3)
50	FLT_50_SUNNYSD7_345KV_SB	**Stuck Breaker at Sunnyside 345kV (515136)** a. Apply single phase fault at the Sunnyside 345kV bus. b. Clear fault after 16 cycles by tripping the following elements: - Sunnyside (515136) to Terry Rd (511568) 345kV CKT 1. - Sunnyside (515136) to Johnson Co. (514809) 345kV CKT 1
51	FLT_51_SUNNYSD7_345KV_SB	**Stuck Breaker at Sunnyside 345kV (515136)** a. Apply single phase fault at the Sunnyside 345kV bus. b. Clear fault after 16 cycles by tripping the following elements: - Sunnyside (515136) to Terry Rd (511568) 345kV CKT 1. - Sunnyside (515136) to G16-063-TAP (560088) 345kV CKT 1
52	FLT_52_SUNNYSD7_345KV_SB	**Stuck Breaker at Sunnyside 345kV (515136)** a. Apply single phase fault at the Sunnyside 345kV bus. b. Clear fault after 16 cycles by tripping the following elements: - Sunnyside (515136) to Johnson Co. (514809) 345kV CKT 1. - Sunnyside (515136) to G16-063-TAP (560088) 345kV CKT 1
53	FLT_53_JOHNCO7_345KV_SB	**Stuck Breaker at Johnson County 345kV (514809)** a. Apply single phase fault at the Johnson County 345kV bus. b. Clear fault after 16 cycles by tripping the following elements: - Johnson Co. 345kV (514809) to 138kV (514808) to 13.2kV (514810) CKT 1 - Johnson Co. (514809) to Pittsburg (510907) 345kV CKT 1
54	FLT_54_JOHNCO7_345KV_SB	**Stuck Breaker at Johnson County 345kV (514809)** a. Apply single phase fault at the Johnson County 345kV bus. b. Clear fault after 16 cycles by tripping the following elements: - Johnson Co. (514809) to Sunnyside (515136) 345kV CKT 1 - Johnson Co. (514809) to Pittsburg (510907) 345kV CKT 1
55	FLT_55_JOHNCO7_345KV_SB	**Stuck Breaker at Johnson County 345kV (514809)** a. Apply single phase fault at the Johnson County 345kV bus. b. Clear fault after 16 cycles by tripping the following elements: - Johnson Co. 345kV (514809) to 138kV (514808) to 13.2kV (514810) CKT 1 - Johnson Co. (514809) to Sunnyside (515136) 345kV CKT 1
56	FLT_56_LES7_345KV_SB	**Stuck Breaker at Lawton Eastside 345kV (511468)** a. Apply single phase fault at the Lawton Eastside 345kV bus. b. Clear fault after 16 cycles by tripping the following elements: - Lawton Eastside 345kV (511468) to 138kV (511467) to 13.8kV (511414) CKT 1 (XF4) - Lawton Eastside 345kV (511468) to Terry Road (511568) 345kV CKT 1
57	FLT_57_LES7_345KV_SB	**Stuck Breaker at Lawton Eastside 345kV (511468)** a. Apply single phase fault at the Lawton Eastside 345kV bus. b. Clear fault after 16 cycles by tripping the following elements: - Lawton Eastside 345kV (511468) to Terry Road (511568) 345kV CKT 1 - Lawton Eastside 345kV (511468) to Oklaunion (511456) 345kV CKT 1
58	FLT_58_LES7_345KV_SB	**Stuck Breaker at Lawton Eastside 345kV (511468)** a. Apply single phase fault at the Lawton Eastside 345kV bus. b. Clear fault after 16 cycles by tripping the following elements: - Lawton Eastside 345kV (511468) to G16-091-TAP (587744) 345kV CKT 1 - Lawton Eastside 345kV (511468) to Terry Road (511568) 345kV CKT 1

No	Cont. Name	Description
59	FLT_59_LES7_345KV_SB	**Stuck Breaker at Lawton Eastside 345kV (511468)** a. Apply single phase fault at the Lawton Eastside 345kV bus. b. Clear fault after 16 cycles by tripping the following elements: - Lawton Eastside 345kV (511468) to G16-091-TAP (587744) 345kV CKT 1 - Lawton Eastside 345kV (511468) to Oklaunion (511456) 345kV CKT 1
60	FLT_60_CARTRCO4_RATLIFF4_138kV_3PH_PO1	**PO1: Prior Outage of the Carter Co – Sunnyside 138kV CKT 1.** 3 phase fault on the Carter Co (515561) to Ratliff (515129) 138kV CKT 1, near Carter Co. a. Apply fault at the Carter Co 138kV bus. b. Clear fault after 7 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 7 cycles, then trip the line in (b) and remove fault.
61	FLT_61_CARTRCO4_POOLVIL4_138kV_3PH_PO1	**PO1: Prior Outage of the Carter Co – Sunnyside 138kV CKT 1.** 3 phase fault on the Carter Co (515561) to Pooleville (515130) 138kV CKT 1, near Carter Co. a. Apply fault at the Carter Co 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line and all sections between Pooleville (515130) to Healdton Tap (515141). c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
62	FLT_62_SUNNYSD4_LONEGRV4_138kV_3PH_PO1	**PO1: Prior Outage of the Carter Co – Sunnyside 138kV CKT 1.** 3 phase fault on the Sunnyside (515135) to Love Grove (515144) to 138kV CKT 1, near Sunnyside. a. Apply fault at the Sunnyside 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line and all sections between Lone Grove (515144) to Healdton Tap (515141). c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
63	FLT_63_CARTRCO4_RATLIFF4_138kV_3PH_PO2	**PO2: Prior Outage of the Carter Co – Pooleville 138kV CKT 1.** 3 phase fault on the Carter Co (515561) to Ratliff (515129) 138kV CKT 1, near Carter Co. a. Apply fault at the Carter Co 138kV bus. b. Clear fault after 7 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 7 cycles, then trip the line in (b) and remove fault.
64	FLT_64_CARTRCO4_SUNNYSD4_138kV_3PH_PO2	**PO2: Prior Outage of the Carter Co – Pooleville 138kV CKT 1.** 3 phase fault on the Carter Co (515561) to Sunnyside (515135) 138kV CKT 1, near Carter Co. a. Apply fault at the Carter Co 138kV bus. b. Clear fault after 7 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 7 cycles, then trip the line in (b) and remove fault.
65	FLT_65_CARTRCO4_POOLVIL4_138kV_3PH_PO3	**PO3: Prior Outage of the Carter Co – Ratliff 138kV CKT 1.** 3 phase fault on the Carter Co (515561) to Pooleville (515130) 138kV CKT 1, near Carter Co. a. Apply fault at the Carter Co 138kV bus. b. Clear fault after 7 cycles by tripping the faulted line and all sections between Pooleville (515130) to Healdton Tap (515141). c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 7 cycles, then trip the line in (b) and remove fault.
66	FLT_66_CARTRCO4_SUNNYSD4_138kV_3PH_PO3	**PO3: Prior Outage of the Carter Co – Ratliff 138kV CKT 1.** 3 phase fault on the Carter Co (515561) to Sunnyside (515135) 138kV CKT 1, near Carter Co. a. Apply fault at the Carter Co 138kV bus. b. Clear fault after 7 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 7 cycles, then trip the line in (b) and remove fault.

No	Cont. Name	Description
67	FLT_67_SUNNYSD7_JOHNCO7_345kV_3PH_PO4	**PO4: Prior Outage of the Sunnyside – Terry Road 345kV CKT 1.** 3 phase fault on the Sunnyside (515136) to Johnson Co. (514809) 345kV CKT 1, near Sunnyside. a. Apply fault at the Sunnyside 345kV 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.
68	FLT_68_SUNNYSD7_G1663TAP_345kV_3PH_PO4	**PO4: Prior Outage of the Sunnyside – Terry Road 345kV CKT 1.** 3 phase fault on the Sunnyside (515136) to G16-063-TAP (560088) 345kV CKT 1, near Sunnyside. a. Apply fault at the Sunnyside 345kV 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.
69	FLT_69_SUNNYSD7_TERRYRD7_345kV_3PH_PO4	**PO4: Prior Outage of the Sunnyside – Terry Road 345kV CKT 1.** 3 phase fault on the Sunnyside (515136) to Terry Road (511568) 345kV line CKT 1, near Sunnyside. a. Apply fault at the Sunnyside 345kV 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.
70	FLT_70_LES7_OKU7_345kV_3PH_PO5	**PO5: Prior Outage of the LES – Terry Road 345kV CKT 1.** 3 phase fault on the Lawton Eastside (511468) to Oklaunion (511456) 345kV line CKT 1, near Lawton Eastside. a. Apply fault at the Lawton Eastside 345kV 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.
71	FLT_71_LES7_G16091TAP_345kV_3PH_PO5	**PO5: Prior Outage of the LES – Terry Road 345kV CKT 1.** 3 phase fault on the Lawton Eastside (511468) to G16-091-TAP (587744) 345kV line CKT 1, near Lawton Eastside. a. Apply fault at the Lawton Eastside 345kV 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.
72	FLT_72_LES7_XF4_345_138kV_3PH_PO5	**PO5: Prior Outage of the LES – Terry Road 345kV CKT 1.** 3 phase fault on the Lawton Eastside 345kV (511468) to 138kV (511467) to 13.8kV (511414) CKT 1 (XF4), near Lawton Eastside 345kV. a. Apply fault at the Lawton Eastside 345kV bus. b. Clear fault after 6 cycles by tripping the faulted transformer.
73	FLT_73_HUGO7_VALIANT7_345kV_3PH_PO6	**PO6: Prior Outage of the Hugo – GEN-2016-063 Tap 345kV CKT 1.** 3 phase fault on the Hugo (521157) to Valiant (587744) 345kV line CKT 1, near Hugo. a. Apply fault at the Hugo 345kV 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.
74	FLT_74_HUGO7_XF_345_138kV_3PH_PO6	**PO6: Prior Outage of the Hugo – GEN-2016-063 Tap 345kV CKT 1.** 3 phase fault on the Hugo (521157) to 138kV (520948) to 13.8kV (521189) CKT 1, near Hugo 345kV. a. Apply fault at the Hugo 345kV bus. b. Clear fault after 6 cycles by tripping the faulted transformer.

No	Cont. Name	Description
75	FLT_75_JOHNCO7_SUNNYSD7_345kV_3PH_PO7	**PO7: Prior Outage of the Johnson Co. – Pittsburg 345kV CKT 1.** 3 phase fault on the Johnson Co. (514809) to Sunnyside (515136) 345kV CKT 1, near Johnson Co. a. Apply fault at the Johnson Co. 345kV 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.
76	FLT_76_JOHNCO7_XF_345_138kV_3PH_PO7	**PO7: Prior Outage of the Johnson Co. – Pittsburg 345kV CKT 1.** 3 phase fault on the Johnson Co. 345kV (514809) to 138kV (514808) to 13.2kV (514810) CKT 1, near Johnson Co. 345kV. a. Apply fault at the Johnson Co. 345kV bus. b. Clear fault after 7 cycles by tripping the faulted transformer.

Appendix E Short Circuit Analysis Results

E.1 Pre-Project Results

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2016 MDWG FINAL WITH 2015 SERIES MMWG FINAL
 MDWG 2026S WITH MMWG 2026S WITHOUT G17-027

 OPTIONS USED:
     - SET PRE-FAULT VOLTAGE ON ALL BUSES TO  1.00 PU AT 0 PHASE SHIFT ANGLE
     - SET SYNCHRONOUS/ASYNCHRONOUS MACHINE POWER OUTPUTS TO P=0.0, Q=0.0
     - SET GENERATOR POSITIVE SEQUENCE REACTANCES TO SUBTRANSIENT
     - SET TRANSFORMER TAP RATIOS=1.0 PU AND PHASE SHIFT ANGLES=0.0
     - SET LINE CHARGING=0.0 IN +/-/0 SEQUENCES
     - SET LINE/FIXED/SWITCHED SHUNTS=0.0 AND TRANSFORMER MAGNETIZING ADMITTANCE=0.0
IN +/-/0 SEQUENCES
     - SET LOAD=0.0 IN +/- SEQUENCES
     - DC LINES AND FACTS DEVICES BLOCKED
     - IMPEDANCE CORRECTIONS NOT APPLIED TO TRANSFORMER ZERO SEQUENCE IMPEDANCES

                                            THREE PHASE FAULT
 X---------- BUS ----------X                  /I+/     AN(I+)
 510907 [PITTSB-7    345.00] AMP           13567.0    -84.59
 510911 [VALIANT7    345.00] AMP           13113.1    -85.34
 511467 [L.E.S.-4    138.00] AMP           24443.7    -84.44
 511468 [L.E.S.-7    345.00] AMP           13027.3    -84.76
 511568 [TERRYRD7    345.00] AMP            9882.1    -85.06
 511571 [RUSHSPR7    345.00] AMP            6341.7    -85.01
 515044 [SEMINOL4    138.00] AMP           40005.1    -85.65
 515097 [WLNUTCK4    138.00] AMP            9203.5    -80.43
 515099 [PALIOGE2    69.000] AMP            8051.4    -81.13
 515100 [PAOLI- 4    138.00] AMP           10213.7    -79.31
 515114 [CHIGLEY4    138.00] AMP            8081.7    -79.95
 515124 [MAYSVIL4    138.00] AMP            6095.4    -74.54
 515127 [WLDHRST2    69.000] AMP            4913.1    -79.45
 515128 [RATLIFF2    69.000] AMP            5002.8    -79.89
 515129 [RATLIFF4    138.00] AMP            6352.9    -76.30
 515130 [POOLVIL4    138.00] AMP            7975.0    -79.99
 515131 [FOX     4   138.00] AMP            6599.7    -78.74
 515132 [DUNDEE 4    138.00] AMP            6138.8    -77.97
 515134 [PRARPNT4    138.00] AMP            5329.0    -74.19
 515135 [SUNNYSD4    138.00] AMP           17780.5    -84.15
 515136 [SUNNYSD7    345.00] AMP           10765.8    -84.68
 515137 [UNIROY 4    138.00] AMP           12271.4    -80.18
 515138 [CARTER 4    138.00] AMP           12326.5    -79.50
 515139 [HEALDTN2    69.000] AMP            4264.5    -76.81
 515140 [HLTNTAP2    69.000] AMP            5013.7    -80.25
 515141 [HLTNTAP4    138.00] AMP            6457.0    -78.01
 515142 [DILLARD4    138.00] AMP            7474.9    -78.63
 515143 [WOLFCRK4    138.00] AMP            9342.9    -79.78
 515144 [LONEGRV4    138.00] AMP           12863.2    -81.97
 515145 [SINCPLT2    69.000] AMP            5008.6    -80.23
 515146 [SINCLAR2    69.000] AMP            3822.2    -73.73
 515372 [ARDWEST4    138.00] AMP           12124.5    -79.99
 515561 [CARTRCO4    138.00] AMP            8148.4    -80.03
 515563 [ORIGINW4    138.00] AMP            5049.5    -83.20
 515570 [MAYSVLT4    138.00] AMP            5724.9    -74.15
 515643 [HONEYCK4    138.00] AMP            8995.6    -81.03
 515805 [COUTYTP2    69.000] AMP            4754.7    -78.66
 520948 [HUGO PP4    138.00] AMP           22242.1    -86.96
 521157 [HUGO    7   345.00] AMP           11053.3    -86.01
 560088 [G16-063-TAP 345.00] AMP            7471.0    -86.04
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E.2 Post-Project Results

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2016 MDWG FINAL WITH 2015 SERIES MMWG FINAL
 MDWG 2026S WITH MMWG 2026S

 OPTIONS USED:
     - SET PRE-FAULT VOLTAGE ON ALL BUSES TO  1.00 PU AT 0 PHASE SHIFT ANGLE
     - SET SYNCHRONOUS/ASYNCHRONOUS MACHINE POWER OUTPUTS TO P=0.0, Q=0.0
     - SET GENERATOR POSITIVE SEQUENCE REACTANCES TO SUBTRANSIENT
     - SET TRANSFORMER TAP RATIOS=1.0 PU AND PHASE SHIFT ANGLES=0.0
     - SET LINE CHARGING=0.0 IN +/-/0 SEQUENCES
     - SET LINE/FIXED/SWITCHED SHUNTS=0.0 AND TRANSFORMER MAGNETIZING ADMITTANCE=0.0 IN
+/-/0 SEQUENCES
     - SET LOAD=0.0 IN +/- SEQUENCES
     - DC LINES AND FACTS DEVICES BLOCKED
     - IMPEDANCE CORRECTIONS NOT APPLIED TO TRANSFORMER ZERO SEQUENCE IMPEDANCES

                                          THREE PHASE FAULT
 X---------- BUS ----------X                 /I+/     AN(I+)
 510907 [PITTSB-7    345.00] AMP    13588.7    -84.58
 510911 [VALIANT7    345.00] AMP    13125.3    -85.33
 511467 [L.E.S.-4    138.00] AMP    24458.6    -84.44
 511468 [L.E.S.-7    345.00] AMP    13045.4    -84.74
 511568 [TERRYRD7    345.00] AMP     9913.3    -85.04
 511571 [RUSHSPR7    345.00] AMP     6353.0    -84.99
 515044 [SEMINOL4    138.00] AMP    40047.8    -85.62
 515097 [WLNUTCK4    138.00] AMP     9218.8    -80.40
 515099 [PALIOGE2    69.000] AMP     8066.4    -81.10
 515100 [PAOLI- 4    138.00] AMP    10272.1    -79.19
 515114 [CHIGLEY4    138.00] AMP     8106.2    -79.89
 515124 [MAYSVIL4    138.00] AMP     6167.3    -74.34
 515127 [WLDHRST2    69.000] AMP     5009.2    -79.37
 515128 [RATLIFF2    69.000] AMP     5103.0    -79.82
 515129 [RATLIFF4    138.00] AMP     6718.5    -75.80
 515130 [POOLVIL4    138.00] AMP     8762.1    -79.58
 515131 [FOX     4   138.00] AMP     7025.8    -78.35
 515132 [DUNDEE 4    138.00] AMP     6372.9    -77.66
 515134 [PRARPNT4    138.00] AMP     5486.0    -73.83
 515135 [SUNNYSD4    138.00] AMP    18216.7    -83.93
 515136 [SUNNYSD7    345.00] AMP    10888.0    -84.62
 515137 [UNIROY 4    138.00] AMP    12424.5    -80.01
 515138 [CARTER 4    138.00] AMP    12444.3    -79.36
 515139 [HEALDTN2    69.000] AMP     4318.3    -76.66
 515140 [HLTNTAP2    69.000] AMP     5085.0    -80.13
 515141 [HLTNTAP4    138.00] AMP     6669.5    -77.71
 515142 [DILLARD4    138.00] AMP     7666.6    -78.37
 515143 [WOLFCRK4    138.00] AMP     9555.1    -79.54
 515144 [LONEGRV4    138.00] AMP    13151.7    -81.75
 515145 [SINCPLT2    69.000] AMP     5079.7    -80.11
 515146 [SINCLAR2    69.000] AMP     3862.5    -73.57
 515372 [ARDWEST4    138.00] AMP    12269.2    -79.83
 515561 [CARTRCO4    138.00] AMP     8985.4    -79.60
 515563 [ORIGINW4    138.00] AMP     5237.9    -83.12
 515570 [MAYSVLT4    138.00] AMP     5804.8    -73.93
 515643 [HONEYCK4    138.00] AMP     9031.8    -80.97
 515805 [COUTYTP2    69.000] AMP     4843.8    -78.57
 520948 [HUGO PP4    138.00] AMP    22255.8    -86.95
 521157 [HUGO    7   345.00] AMP    11066.0    -86.00
 560088 [G16-063-TAP 345.00] AMP     7498.0    -86.03
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Appendix F Simulation Plots

F.1 Plots for 2017WP Post-Project Case

See separate file “AppF-1_2017W_plots_post-case.PDF”

F.2 Plots for 2017WP Pre-Project Case

See separate file "AppF-2_2017W_plots_pre-case.PDF"

F.3 Plots for 2018SP Post-Project Case

See separate file “AppF-3_2018S_plots_post-case.PDF”

F.4 Plots for 2026SP Post-Project Case

See separate file "AppF-4_2026S_plots_post-case.PDF"