GEN-2014-040
Impact Restudy for Generator Modification (Turbine Change)

April 2016
Generator Interconnection

Southwest Power Pool

Revision History

Date	Author	Change Description
4/8/2016	SPP	GEN-2014-040 Impact Restudy for Generator Modification (Turbine Change) issued.

Executive Summary

The GEN-2014-040 Interconnection Customer has requested a modification to its Generator Interconnection Request to change from one hundred sixty (160) Vestas V110 2.0 MW wind turbine generators (aggregate power of 320.0 MW) to one hundred thirty-nine (139) GE 2.3 MW wind turbine generators (aggregate power of 319.7 MW). The point of interconnection (POI) is the Southwestern Public Service Company (SPS) Castro County Substation 115kV. ABB performed the study for this modification request, and ABB's report on the study follows this summary.

The study models used were the 2016 winter, the 2017 summer, and the 2025 summer cases and included Interconnection Requests through DISIS-2015-001. The study showed that no stability problems were found with the contingencies studied during the summer and the winter peak conditions as a result of changing to the GE 2.3 MW wind turbine generators. Additionally, the project wind farm was found to stay connected during the contingencies that were studied and, therefore, will meet the Low Voltage Ride Through (LVRT) requirements of FERC Order #661A.

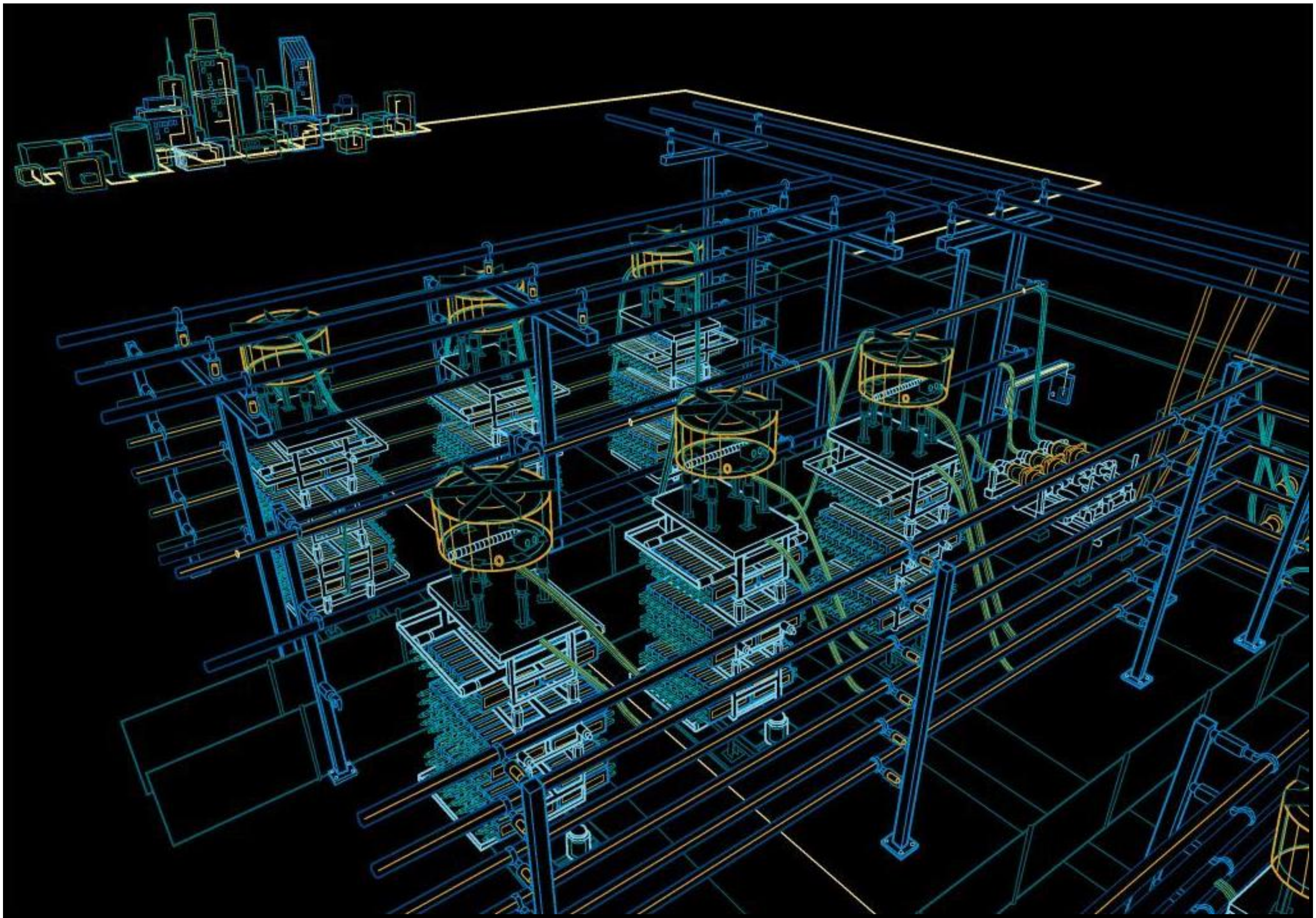
A power factor analysis was performed and GEN-2014-040 will be required to meet the 0.95 power factor lagging (providing vars) to 0.95 power factor leading (absorbing vars) at the POI. A short circuit analysis was performed and is detailed in the ABB report.

A low-wind/no-wind condition analysis was performed for this modification request. The project will be required to install a total of approximately 24 Mvars of shunt reactors on its substation 34.5kV bus(es). This is necessary to offset the capacitive effect on the transmission network caused by the project's transmission line and collector system during low-wind/no-wind conditions.

With the assumptions outlined in this report and with all required network upgrades in place, GEN-2014-040 with the GE 2.3 MW wind turbine generators should be able to reliably interconnect to the SPP transmission grid.

It should be noted that this study analyzed the requested modification to change generator technology, manufacturer, and layout. This study analyzed many of the most probable contingencies, but it is not an all-inclusive list and cannot account for every operational situation. It is likely that the customer may be required to reduce its generation output to 0 MW, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

Nothing in this study should be construed as a guarantee of transmission service. If the Customer wishes to obtain deliverability to a specific customer, a separate request for transmission service shall be requested on Southwest Power Pool's OASIS.



Southwest Power Pool

GEN-2014-040 SYSTEM IMPACT RESTUDY FOR GENERATOR MODIFICATION

Final Report

Report No. r00

6 April 2016

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SUMMARY

Southwest Power Pool (SPP) has commissioned ABB Inc., to perform a System Impact Restudy for Generator Modification for generation interconnection request GEN-2014-040 (319.7 MW wind farm connected at the Castro 115 kV bus located at Castro County, Texas).

Request	Size (MW)	Generator Model	POI
GEN-2014-040	319.7	GE 2.3 MW	Castro County 115 kV bus

The objective of this study is to re-evaluate the impact of project GEN-2014-040 on existing and future system performance based on an updated wind farm design (wind turbine-generators and collector system) as specified by the Interconnection Customer. While the previous study was based on a total of 160 Vestas V110 2.0 MW wind turbine-generators, the present study is based on a total of 139 GE 2.3 MW wind-turbine generators.

The study is performed on three system scenarios provided by SPP:

- 2016 Winter Peak Case
- 2017 Summer Peak Case
- 2025 Summer Peak Case

The scope of the study included stability analysis, short-circuit analysis, power factor evaluation and low-wind/no-wind analysis. The following is a summary of study results.

Results of the Stability Analysis show no stability problems or voltage violations for all studied disturbances on three seasons. The simulation results are summarized in Table 2-2, Table 2-3 and Table 2-4. Based on the results of the stability analysis, the conclusion is that the proposed GEN-2014-040 will not cause stability problems.

System short-circuit current levels at up to five buses away from the point of interconnection were calculated and tabulated for SPP's reference.

Power Factor Analysis was performed to check whether the studied project meets FERC and SPP power factor requirements for wind farm interconnections. The wind farm is required to meet the 95% lagging (injecting MVAr into the grid) and 95% leading (absorbing MVAr from the grid) power factor requirements at the Point of Interconnection.

The Low/No Wind analysis shows that 23.83 MVAr of shunt reactance is required at the POI to bring the MVAr flow at the POI down to approximately zero under low/no wind conditions for three

studied seasons. The reactor bank size is approximate and the final size will be determined in the final facility and collector system design.

Contents

1 INTRODUCTION

Southwest Power Pool (SPP) has commissioned ABB Inc., to perform a System Impact Restudy for Generator Modification for generation interconnection request GEN-2014-040 (319.7 MW wind farm connected at the Castro 115 kV bus located at Castro County, Texas) as shown in Table 1-1.

Table 1-1: GEN-2014-040 Generation Interconnection Request

Request	Size (MW)	Generator Model	POI
GEN-2014-040	319.7	GE 2.3 MW (wind)	Castro County 115 kV bus

The objective of this study is to re-evaluate the impact of project GEN-2014-040 on existing and future system performance based on an updated wind farm design (wind turbine-generators and collector system) as specified by the Interconnection Customer. While the previous study was based on a total of 160 Vestas V110 2.0 MW wind turbine-generators, the present study is based on a total of 139 GE 2.3 MW wind-turbine generators.

The scope of the study included stability analysis, short-circuit analysis, power factor evaluation and low-wind/no-wind analysis.

The study is performed on three system scenarios provided by SPP:

- 2016 Winter Peak Case
- 2017 Summer Peak Case
- 2025 Summer Peak Case

SPP provided the study cases for three system scenarios which include GEN-2014-040 modeled on the basis of Vestas V110 2.0 MW wind turbine-generators. The following changes were made by ABB to update the three cases.

- The proposed wind farm is modeled at 100% of nameplate, compared to 20% in the provided cases. Wind farm representation, including collector system, generator step-up transformer, and substation transformer, are updated based on the data provided by the Interconnection Customer.

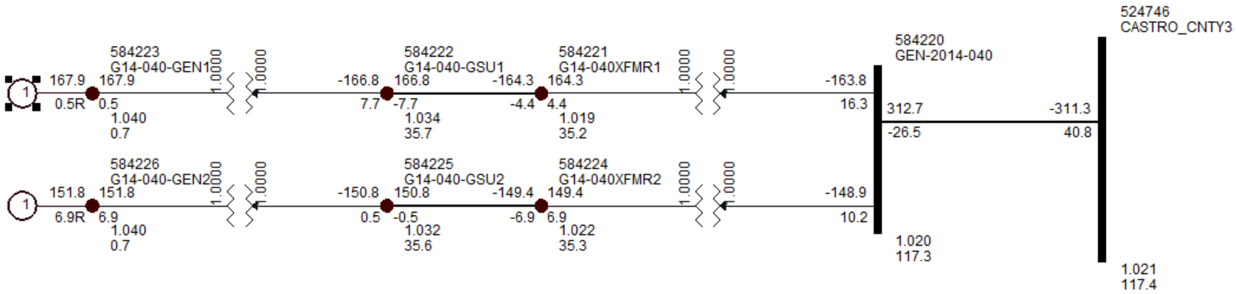
- The dynamic model of the Vestas V110 2.0 MW wind turbine-generator in the provided cases is replaced by the GE 2.3 MW wind-turbine generator model.
- The dispatches of prior-queued projects summarized in Table 1-2 are increased from 20% of nameplate as in the provided cases to 100% by using the automation files provided by SPP.
- The generators in SPP footprint, defined by the automation file ("2015_MDWG_DIS1501_Scale_Subsystem.idv") provided by SPP, are re-dispatched down by incremental dispatch amounts of the proposed wind farm and prior-queued projects in Table 1-2.

Table 1-2: Prior-Queued Projects

Request	Size (MW)	Generator Model	Point of Interconnection
GEN-2002-022	240	Siemens 2.3 MW	Bushland 230 kV (524267)
GEN-2008-051	322	Siemens 2.3 MW	Potter 345 kV (523961)
GEN-2003-020	159	GE 1.5 MW (523941, 523942)	Carson Co. 115 kV (523924)
GEN-2001-036	80	Mitsubishi 1000	Norton 115 kV (524502)
GEN-2001-033	180	Mitsubishi 1000	San Juan Mesa 230 kV (524885)
GEN-2008-022	300	Vestas	Tap on Eddy County – Tolk 345 kV line (G08-022-POI, 560007)
GEN-2014-033	70	SC 500HE/CP 0.5 MVA inverter	Chaves County 115 kV
GEN-2014-034	70	SC 500HE/CP 0.5 MVA inverter	Chaves County 115 kV
GEN-2014-035	30	SC 500HE/CP 0.5 MVA inverter	Chaves County 115 kV
GEN-2014-047	40	AE 500NX 0.5 MW PV inverters	Tap Tolk - Eddy County (Crossroads) 345 kV

The one line diagram for the study project is shown in Figure 1-1.

Figure 1-1: One Line Diagram for the Study Project



2 STABILITY ANALYSIS

In this study, ABB investigated the stability of the system for faults in the vicinity of the proposed plant as defined by SPP. The studied faults involve three-phase transformer faults with normal clearing, three-phase line faults with normal clearing and re-closing, and single-line-to-ground faults with stuck breaker (SB-1PH).

2.1 Stability Analysis Methodology

Stability analysis is performed to determine whether the electric system would meet stability criteria following the addition of the GEN-2014-040 project. Stability analysis was performed using Siemens-PTI's PSS/E dynamics program V32.2.2. All the faults listed in Table 2-1 were simulated for 20 seconds.

Table 2-1: List of Faults for Stability Analysis

Cont. No.	Cont. Name	Description
1	FLT_01_3PH	3 phase fault on the Castro County (524746) to Deaf Smith #21 (524734) 115kV line circuit 1, near Castro County. a. Apply fault at the Castro County 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
2	FLT_02_3PH	3 phase fault on the Castro County (524746) to BC-Kelley (525050) 115kV line circuit 1, near Castro County. a. Apply fault at the Castro County 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
3	FLT_03_3PH	3 phase fault on the Castro County (524746) to Newhart (525460) 115kV line circuit 1, near Castro County. a. Apply fault at the Castro County 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
4	FLT_04_3PH	3 phase fault on the DS #21 (524734) to Deaf Smith (524622) 115kV line circuit 1, near DS #21. a. Apply fault at the DS #21 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
5	FLT_05_3PH	3 phase fault on the Deaf Smith (524622) to NE_Hereford (524567) 115kV line circuit 1, near Deaf Smith. a. Apply fault at the Deaf Smith 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Cont. No.	Cont. Name	Description
6	FLT_06_3PH	3 phase fault on the Deaf Smith (524622) to Panda (524597) 115kV line circuit 1, near Deaf Smith. a. Apply fault at the Deaf Smith 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
7	FLT_07_3PH	3 phase fault on the Deaf Smith (524622) to Hereford (524606) 115kV line circuit 1, near Deaf Smith. a. Apply fault at the Deaf Smith 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
8	FLT_08_3PH	3 phase fault on the Castro County 115 (524746) /69 (524745) kV autotransformer circuit 1, near Castro County 115kV (524746). a. Apply fault at the Castro County 115kV bus. b. Clear fault after 5 cycles and trip the faulted TX.
9	FLT_09_3PH	3 phase fault on the BC-Earth (525056) to Plant X (525480) 115kV line circuit 1, near BC-Earth. a. Apply fault at the BC-Earth 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
10	FLT_10_3PH	3 phase fault on the Plant X (525480) to EMU&VLY_TP (525019) 115kV line circuit 1, near Plant X. a. Apply fault at the Plant X 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
11	FLT_11_3PH	3 phase fault on the Plant X (525480) to LC-S_Olton (525440) 115kV line circuit 1, near Plant X. a. Apply fault at the Plant X 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
12	FLT_12_3PH	3 phase fault on the Plant X (525480) to Hale County (525454) 115kV line circuit 1, near Plant X. a. Apply fault at the Plant X 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
13	FLT_13_3PH (Case 25SP only)	3 phase fault on the Plant X (525480) to W_LITLFLD (525614) 115kV line circuit 1, near Plant X. a. Apply fault at the Plant X 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Cont. No.	Cont. Name	Description
14	FLT_14_3PH	3 phase fault on the New Hart (525460) to Hart Industrial (525124) 115kV line circuit 1, near New Hart. a. Apply fault at the New Hart 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
15	FLT_15_3PH	3 phase fault on the Newhart (525460) to Kress (525192) 115kV line circuit 1, near Newhart. a. Apply fault at the Newhart 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
16	FLT_16_3PH	3 phase fault on the Deaf Smith (524623) 230/(524622) 115/(524620) 13.2kV Transformer circuit 1, near the 230kV bus. a. Apply fault at the Deaf Smith 230kV bus. b. Clear fault after 5 cycles and trip the faulted line.
17	FLT_17_3PH	3 phase fault on the Newhart 230/(525461) 115/(525460) 13.2kV Transformer circuit 1, near the 230kV bus. a. Apply fault at the Newhart Smith 230kV bus. b. Clear fault after 5 cycles and trip the faulted line.
18	FLT_18_SB_1PH	**Castro stuck breaker** a. Apply single phase fault at Castro County on the Castro (524746) – BC-Kelley (525050) 115kV line b. After 20 cycles, trip the Castro 115kV (524746)/69kV (524745)/ 13.2kV (524743) transformer c. Remove the fault and trip the faulted line
19	FLT_19_SB_1PH	**Castro stuck breaker** a. Apply single phase fault at Castro County on the Castro (524746) – Newhart (525460) 115kV line b. After 20 cycles, trip the Castro 115kV (524746)/69kV (524745)/ 13.2kV (524744) transformer c. Remove the fault and trip the faulted line
20	FLT_20_SB_1PH	**Castro stuck breaker** a. Apply single phase fault at Castro County on the Castro (524746) – Newhart (525460) 115kV line b. After 20 cycles, trip the Castro 115kV (524746) – DS-21 (524734) 115kV line c. Remove the fault and trip the faulted line
21	FLT_21_PO	**Prior outage on the Castro – Newhart 115kV line** 3 phase fault on the Castro County (524746) to BC-Kelley (525050) 115kV line circuit 1, near Castro County. a. Apply fault at the Castro County 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Cont. No.	Cont. Name	Description
22	FLT_22_PO	**Prior outage on the Castro – DS-21 115kV line** 3 phase fault on the Castro County (524746) to BC-Kelley (525050) 115kV line circuit 1, near Castro County. a. Apply fault at the Castro County 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
24	FLT_24_3PH	3 phase fault on the Plant X (525481) - Newhart (525461) 230kV line circuit 1, near Plant X. a. Apply fault at the Plant X 230 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
25	FLT_25_3PH	3 phase fault on the Plant X (525481) - Deaf Smith (524623) 230kV line circuit 1, near Plant X. a. Apply fault at the Plant X 230 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
26	FLT_26_3PH	3 phase fault on the Tuco (525830) - Tolk East (525524) 230kV line circuit 1 near Tuco 230 kV. a. Apply fault at the Tuco 230 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
27	FLT_27_3PH	3 phase fault on the Plant X (525481) - Tolk East (525524) 230kV line circuit 1, near Plant X. a. Apply fault at the Plant X 230 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
28	FLT_28_3PH	3 phase fault on the Tuco (525832) to GEN-2014-074 Tap (560027) 345kV line near Tuco 345 kV. a. Apply fault at the Tuco 345 kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
29	FLT_29_3PH	3 phase fault on the Plant X (525481) 230/(525480) 115/(525479) 13.2kV Transformer circuit 1, near the 230 kV bus. a. Apply fault at the Plant X 230 kV bus. b. Clear fault after 5 cycles and trip the faulted line.
30	FLT_30_3PH	3 phase fault on the Plant X (525480) to Lamb County (525636) 115kV line circuit 1, near Plant X 115 kV. a. Apply fault at the Plant X 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Cont. No.	Cont. Name	Description
31	FLT_31_3PH	3 phase fault on the Deaf Smith (524623) to Bushland (524267) 230kV line circuit 1, near Deaf Smith. a. Apply fault at the Deaf Smith 230kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
32	FLT_32_3PH	3 phase fault on the Plant X (525481) to Sundown (526435) 230kV line circuit 1, near Plant X. a. Apply fault at the Plant X 230kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
33	FLT_33_3PH	3 phase fault on the Newhart (525461) to Potter (523959) 230kV line circuit 1, near Newhart. a. Apply fault at the Newhart 230kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
34	FLT_34_3PH	3 phase fault on the Castro County (524746) to Deaf Smith #22 (524694) 115kV line circuit 1, near Castro County. a. Apply fault at the Castro County 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
35	FLT_35_SB_1PH	**Castro stuck breaker** a. Apply single phase fault at Castro County on the Castro County (524746) – Deaf Smith #22 (524694) 115kV line b. After 20 cycles, trip the faulted line
36	FLT_36_SB_1PH	**Plant X stuck breaker** a. Apply single phase fault at Plant X on the Plant X (525480) - BC-Earth (525056) 115kV line b. After 20 cycles, trip the faulted line
37	FLT_37_PO	**Prior outage on the Castro – Deaf Smith #22 115kV line** 3 phase fault on the Castro County (524746) to BC-Kelley (525050) 115kV line circuit 1, near Castro County. a. Apply fault at the Castro County 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
38	FLT_38_PO	**Prior outage on the Castro 115/69/13.2 kV transformer #1** 3 phase fault on the Castro County (524746) to BC-Kelley (525050) 115kV line circuit 1, near Castro County. a. Apply fault at the Castro County 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Cont. No.	Cont. Name	Description
39	FLT_39_PO	**Prior outage on the Castro – Deaf Smith #22 115kV line** 3 phase fault on the Castro County (524746) to Newhart (525460) 115kV line circuit 1, near Castro County. a. Apply fault at the Castro County 115kV bus. b. Clear fault after 5 cycles and trip the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Single-line-to-ground faults were simulated with the standard method of applying fault impedance to the positive sequence network to represent the effect of the negative and zero sequence networks on the positive sequence network.

The Southwest Pool Disturbance Performance Criteria Requirements in Appendix A were used to evaluate system response during the initial transient period following a disturbance on the system. Generator responses and bus voltages (115 kV and above) in Areas 520 (AEPW), 524 (OKGE), 525 (WFEC), 526 (SPS), 531 (MIDW), 534 (SUNC), and 536 (WERE) were monitored to ensure that the system performance meets criteria. Rotor angles of nearby synchronous generators were plotted to verify whether the generators maintained synchronism and had adequate damping following system disturbances.

SPP requires wind farms to comply with low voltage ride through requirements for wind farms as stipulated in FERC Order 661A. See Appendix G of the "Southwest Power Pool - Open Access Transmission Tariff, Sixth Revised Volume No. 1 - Attachment V Generator Interconnection Procedures (GIP)"[1]. According to these requirements, wind-turbine generators should not be tripped off line for faults by under voltage relay actuation. Generator speeds of pre-queued projects were also monitored to ensure they stay online under system contingencies. For contingencies that result in a prior queued project tripping off-line, SPP requires those contingencies to be re-run with the prior queued project's voltage and frequency tripping disabled.

[1] http://sppoasis.spp.org/documents/swpp/transmission/studies/Attachment_V_GIP.pdf

2.2 Study Results

No disturbances (including all n-1 and stuck breaker disturbances) showed instability problems or voltage violations for three seasons. Table 2-2, Table 2-3, and Table 2-4 show results for the 2016 Winter Peak case, the 2017 Summer Peak case, and the 2025 Summer Peak case, respectively. The “Volt CI Violation” in the table refers to bus voltages exceeding the range of 0.7 pu. or 1.2 pu, 2.5 second after fault clearing, and the “Volt CII Violation” refers to end bus voltages exceeding the range of 0.9 pu. or 1.1 pu at the end of the simulation.

Table 2-2 Study Results Summary, 2016 Winter Peak

Index	Fault File Name	16WP Case		
		Stable?	Volt CI Violation	Volt CII Violation
1	FLT_01_3PH	stable	no	no
2	FLT_02_3PH	stable	no	no
3	FLT_03_3PH	stable	no	no
4	FLT_04_3PH	stable	no	no
5	FLT_05_3PH	stable	no	no
6	FLT_06_3PH	stable	no	no
7	FLT_07_3PH	stable	no	no
8	FLT_08_3PH	stable	no	no
9	FLT_09_3PH	stable	no	no
10	FLT_10_3PH	stable	no	no
11	FLT_11_3PH	stable	no	no
12	FLT_12_3PH	stable	no	no
14	FLT_14_3PH	stable	no	no
15	FLT_15_3PH	stable	no	no
16	FLT_16_3PH	stable	no	no
17	FLT_17_3PH	stable	no	no
18	FLT_18_SB_1PH	stable	no	no
19	FLT_19_SB_1PH	stable	no	no
20	FLT_20_SB_1PH	stable	no	no
21	FLT_21_PO	stable	no	no
22	FLT_22_PO	stable	no	no
24	FLT_24_3PH	stable	no	no
25	FLT_25_3PH	stable	no	no
26	FLT_26_3PH	stable	no	no
27	FLT_27_3PH	stable	no	no
28	FLT_28_3PH	stable	no	no
29	FLT_29_3PH	stable	no	no
30	FLT_30_3PH	stable	no	no
31	FLT_31_3PH	stable	no	no
32	FLT_32_3PH	stable	no	no
33	FLT_33_3PH	stable	no	no
34	FLT_34_3PH	stable	no	no
35	FLT_35_SB_1PH	stable	no	no
36	FLT_36_SB_1PH	stable	no	no
37	FLT_37_PO	stable	no	no
38	FLT_38_PO	stable	no	no
39	FLT_39_PO	stable	no	no

Table 2-3 Study Results Summary, 2017 Summer Peak

Index	Fault File Name	17SP Case		
		Stable?	Volt CI Violation	Volt CII Violation
1	FLT_01_3PH	stable	no	no
2	FLT_02_3PH	stable	no	no
3	FLT_03_3PH	stable	no	no
4	FLT_04_3PH	stable	no	no
5	FLT_05_3PH	stable	no	no
6	FLT_06_3PH	stable	no	no
7	FLT_07_3PH	stable	no	no
8	FLT_08_3PH	stable	no	no
9	FLT_09_3PH	stable	no	no
10	FLT_10_3PH	stable	no	no
11	FLT_11_3PH	stable	no	no
12	FLT_12_3PH	stable	no	no
14	FLT_14_3PH	stable	no	no
15	FLT_15_3PH	stable	no	no
16	FLT_16_3PH	stable	no	no
17	FLT_17_3PH	stable	no	no
18	FLT_18_SB_1PH	stable	no	no
19	FLT_19_SB_1PH	stable	no	no
20	FLT_20_SB_1PH	stable	no	no
21	FLT_21_PO	stable	no	no
22	FLT_22_PO	stable	no	no
24	FLT_24_3PH	stable	no	no
25	FLT_25_3PH	stable	no	no
26	FLT_26_3PH	stable	no	no
27	FLT_27_3PH	stable	no	no
28	FLT_28_3PH	stable	no	no
29	FLT_29_3PH	stable	no	no
30	FLT_30_3PH	stable	no	no
31	FLT_31_3PH	stable	no	no
32	FLT_32_3PH	stable	no	no
33	FLT_33_3PH	stable	no	no
34	FLT_34_3PH	stable	no	no
35	FLT_35_SB_1PH	stable	no	no
36	FLT_36_SB_1PH	stable	no	no
37	FLT_37_PO	stable	no	no
38	FLT_38_PO	stable	no	no
39	FLT_39_PO	stable	no	no

Table 2-4 Study Results Summary, 2025 Summer Peak

Index	Fault File Name	25SP Case		
		Stable?	Volt CI Violation	Volt CII Violation
1	FLT_01_3PH	stable	no	no
2	FLT_02_3PH	stable	no	no
3	FLT_03_3PH	stable	no	no
4	FLT_04_3PH	stable	no	no
5	FLT_05_3PH	stable	no	no
6	FLT_06_3PH	stable	no	no
7	FLT_07_3PH	stable	no	no
8	FLT_08_3PH	stable	no	no
9	FLT_09_3PH	stable	no	no
10	FLT_10_3PH	stable	no	no
11	FLT_11_3PH	stable	no	no
12	FLT_12_3PH	stable	no	no
13	FLT_13_3PH	stable	no	no
14	FLT_14_3PH	stable	no	no
15	FLT_15_3PH	stable	no	no
16	FLT_16_3PH	stable	no	no
17	FLT_17_3PH	stable	no	no
18	FLT_18_SB_1PH	stable	no	no
19	FLT_19_SB_1PH	stable	no	no
20	FLT_20_SB_1PH	stable	no	no
21	FLT_21_PO	stable	no	no
22	FLT_22_PO	stable	no	no
24	FLT_24_3PH	stable	no	no
25	FLT_25_3PH	stable	no	no
26	FLT_26_3PH	stable	no	no
27	FLT_27_3PH	stable	no	no
28	FLT_28_3PH	stable	no	no
29	FLT_29_3PH	stable	no	no
30	FLT_30_3PH	stable	no	no
31	FLT_31_3PH	stable	no	no
32	FLT_32_3PH	stable	no	no
33	FLT_33_3PH	stable	no	no
34	FLT_34_3PH	stable	no	no
35	FLT_35_SB_1PH	stable	no	no
36	FLT_36_SB_1PH	stable	no	no
37	FLT_37_PO	stable	no	no
38	FLT_38_PO	stable	no	no
39	FLT_39_PO	stable	no	no

Figure 2-1 shows the response of the studied generator following fault FLT_01_3PH on the 2016 Winter Peak case. The generator speed, active and reactive power output and terminal voltage are plotted to show the generator response.

All simulation plots are included in Appendix B.

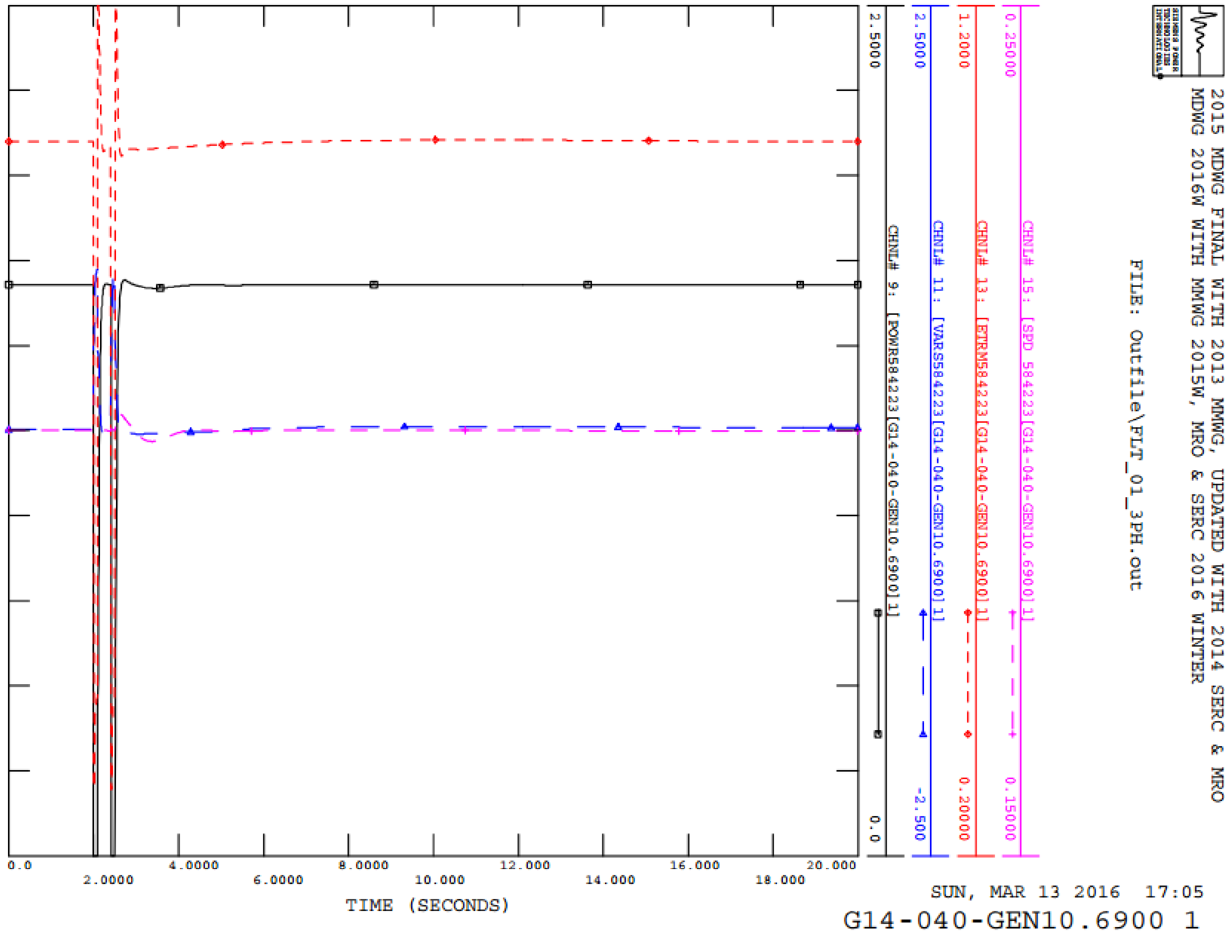


Figure 2-1: GEN-2014-040 Response Following Fault FLT-01-3PH for 2016 Winter Peak Case

3 SHORT CIRCUIT ANALYSIS

Short circuit analysis was performed on the 2017 Summer Peak and 2025 Summer Peak power flow cases using the PSS/E program. Three-phase symmetrical fault current levels were calculated at up to five buses away from the point of interconnection. Table 3-1 tabulates the calculated three-phase fault current levels at buses rated 69 kV and above.

Table 3-1: Three-Phase Fault Currents

2017 SP			2025 SP		
Number	**Name**	**3PH(Amp)**	**Number**	**Name**	**3PH(Amp)**
522800	MU-TULIA 3115.00	5065.3	522800	MU-TULIA 3115.00	5076.0
523095	HITCHLAND 6230.00	15509.2	523095	HITCHLAND 6230.00	15679.1
523221	XIT_INTG 6230.00	2599.2	523221	XIT_INTG 6230.00	2570.5
523267	PRINGLE 6230.00	4279.0	523267	PRINGLE 6230.00	4296.9
523308	MOORE_E 3115.00	10715.8	523308	MOORE_E 3115.00	10809.2
523309	MOORE_CNTY 6230.00	6751.3	523309	MOORE_CNTY 6230.00	6758.7
523869	CHAN/TASCOS6230.00	3836.8	523869	CHAN/TASCOS6230.00	3818.7
523959	POTTER_CO 6230.00	20197.7	523959	POTTER_CO 6230.00	20369.6
523961	POTTER_CO 7345.00	7541.9	523961	POTTER_CO 7345.00	7582.5
523977	HARRNG_WST 6230.00	25918.8	523977	HARRNG_WST 6230.00	26318.5
523978	HARRNG_MID 6230.00	25918.8	523978	HARRNG_MID 6230.00	26318.5
523979	HARRNG_EST 6230.00	25918.8	523979	HARRNG_EST 6230.00	26318.5
524007	ROLLHILLS 3115.00	18991.1	524007	ROLLHILLS 3115.00	19113.9
524010	ROLLHILLS 6230.00	19233.3	524010	ROLLHILLS 6230.00	19426.8
524044	NICHOLS 6230.00	25145.1	524044	NICHOLS 6230.00	25538.8
524266	BUSHLAND 3115.00	9149.2	524266	BUSHLAND 3115.00	9226.2
524267	BUSHLAND 6230.00	9519.4	524267	BUSHLAND 6230.00	9558.0
524290	WILDOR2_JUS6230.00	6527.2	524290	WILDOR2_JUS6230.00	6539.5
524296	SPNSPUR_WND7345.00	4475.4	524296	SPNSPUR_WND7345.00	4483.0
524365	RANDALL 6230.00	14146.0	524365	RANDALL 6230.00	14352.7
524414	AMA_SOUTH 3115.00	16575.3	524414	AMA_SOUTH 3115.00	16563.9
524415	AMA_SOUTH 6230.00	13314.5	524415	AMA_SOUTH 6230.00	13451.5
524516	CANYON_WEST3115.00	4914.2	524516	CANYON_WEST3115.00	5414.9
524530	PALO_DURO 3115.00	6548.6	524530	PALO_DURO 3115.00	6604.3
524554	CENTRE_ST 269.000	3853.7	524554	CENTRE_ST 269.000	3903.9
524561	DS-MTR 269.000	6135.0	524556	CENTRE_ST 3115.00	6113.8
524567	NE_HEREFORD3115.00	9480.8	524561	DS-MTR 269.000	6221.7
524573	NE_HEREFORD269.000	6833.8	524567	NE_HEREFORD3115.00	9495.3
524580	DS-#9 269.000	3227.5	524573	NE_HEREFORD269.000	6914.5
524590	DAWN 3115.00	5194.9	524580	DS-#9 269.000	3319.3
524597	PANDAHFD 3115.00	8266.1	524590	DAWN 3115.00	6202.4
524605	HEREFORD 269.000	4432.3	524597	PANDAHFD 3115.00	8943.5
524606	HEREFORD 3115.00	10590.8	524605	HEREFORD 269.000	4601.9
524622	DEAFSMITH 3115.00	11767.0	524606	HEREFORD 3115.00	10581.0
524623	DEAFSMITH 6230.00	7783.6	524622	DEAFSMITH 3115.00	11715.2
524629	DS-#6 3115.00	6121.5	524623	DEAFSMITH 6230.00	7939.2
524633	DS-#4 269.000	3260.1	524629	DS-#6 3115.00	6181.3
524640	DS-#8 269.000	1937.2	524633	DS-#4 269.000	3352.1

2017 SP			2025 SP		
Number	Name	3PH(Amp)	Number	Name	3PH(Amp)
524655	FRIONA 3115.00	3931.2	524640	DS-#8 269.000	1970.3
524681	DIMMIT_E&S 269.000	2977.5	524655	FRIONA 3115.00	3967.5
524688	DS-#3 269.000	3158.9	524681	DIMMIT_E&S 269.000	2988.3
524694	DS-#22 3115.00	5110.9	524688	DS-#3 269.000	3170.2
524714	CASTRO_TP 269.000	3787.9	524694	DS-#22 3115.00	5137.4
524721	DS-#15&#19 269.000	3829.4	524714	CASTRO_TP 269.000	3800.2
524728	DS-CASTRO 269.000	4615.6	524721	DS-#15&#19 269.000	3843.9
524734	DS-#21 3115.00	11263.1	524728	DS-CASTRO 269.000	4628.2
524745	CASTRO_CNTY269.000	9928.6	524734	DS-#21 3115.00	11382.8
524746	CASTRO_CNTY3115.00	12211.1	524745	CASTRO_CNTY269.000	9938.0
524909	ROSEVELT_N 6230.00	8924.5	524746	CASTRO_CNTY3115.00	12356.6
524911	ROSEVELT_S 6230.00	8924.5	524909	ROSEVELT_N 6230.00	9108.0
525018	EMULESH&VLY3115.00	4860.5	524911	ROSEVELT_S 6230.00	9108.0
525019	EMU&VLY_TP 3115.00	5253.1	525018	EMULESH&VLY3115.00	5929.0
525028	BAILEYCO 3115.00	5047.5	525019	EMU&VLY_TP 3115.00	6531.1
525050	BC-KELLEY 3115.00	8512.3	525028	BAILEYCO 3115.00	6502.5
525056	BC-EARTH 3115.00	8899.5	525050	BC-KELLEY 3115.00	8753.8
525116	DS-#12 269.000	2507.3	525056	BC-EARTH 3115.00	9284.7
525119	BC-SUNYSIDE269.000	1328.4	525116	DS-#12 269.000	2515.2
525122	HART_INDUST269.000	1961.4	525119	BC-SUNYSIDE269.000	1330.0
525124	HART_INDUST3115.00	7539.4	525122	HART_INDUST269.000	1955.7
525132	LC-N_OLTON 269.000	3045.4	525124	HART_INDUST3115.00	7571.9
525153	HAPPY_INT 269.000	3360.0	525132	LC-N_OLTON 269.000	3014.1
525154	HAPPY_INT 3115.00	5357.8	525153	HAPPY_INT 269.000	3316.2
525179	TULIA_TP 3115.00	6268.8	525154	HAPPY_INT 3115.00	5383.2
525191	KRESS_INT 269.000	4351.1	525179	TULIA_TP 3115.00	6287.4
525192	KRESS_INT 3115.00	10886.4	525191	KRESS_INT 269.000	4224.5
525203	SW-KRESS 269.000	4351.1	525192	KRESS_INT 3115.00	10909.3
525212	SWISHER 3115.00	9911.7	525203	SW-KRESS 269.000	4224.5
525213	SWISHER 6230.00	9981.8	525212	SWISHER 3115.00	9877.9
525224	KRESS_RURL 269.000	2470.1	525213	SWISHER 6230.00	10144.6
525225	KRESS_RURAL3115.00	6169.4	525224	KRESS_RURL 269.000	2451.1
525249	LH-PLW&FNY 269.000	1583.0	525225	KRESS_RURAL3115.00	6171.0
525257	N_PLAINVEW 3115.00	5046.1	525249	LH-PLW&FNY 269.000	1587.9
525272	KISER 3115.00	5052.1	525257	N_PLAINVEW 3115.00	5046.8
525291	PLAINVW_TP 269.000	6199.6	525272	KISER 3115.00	5054.2
525298	S_PLAINVEW 269.000	2598.4	525291	PLAINVW_TP 269.000	6147.6
525325	COX 269.000	3126.9	525298	S_PLAINVEW 269.000	2587.9
525326	COX 3115.00	5848.4	525325	COX 269.000	3050.4
525393	SPRINGLAKE 3115.00	9370.7	525326	COX 3115.00	5877.4
525404	LC-OLTON 269.000	4324.8	525393	SPRINGLAKE 3115.00	10090.0
525413	LAMTON 269.000	4932.9	525404	LC-OLTON 269.000	4233.2
525414	LAMTON 3115.00	7786.9	525413	LAMTON 269.000	4804.3
525425	CORNER 269.000	3566.7	525414	LAMTON 3115.00	7932.0
525432	SP-HALFWAY 269.000	5637.4	525425	CORNER 269.000	3538.5
525440	LC-S_OLTON 3115.00	7409.8	525432	SP-HALFWAY 269.000	5590.9
525446	SPGLAKE_TP3 115.00	10534.6	525440	LC-S_OLTON 3115.00	7617.3

2017 SP			2025 SP		
Number	Name	3PH(Amp)	Number	Name	3PH(Amp)
525453	HALE_CNTY 269.000	6573.9	525446	SPGLAKE_TP3 115.00	11469.1
525454	HALE_CNTY 3115.00	10078.4	525453	HALE_CNTY 269.000	6516.5
525460	NEWHART 3115.00	14641.1	525454	HALE_CNTY 3115.00	10233.8
525461	NEWHART 6230.00	10731.9	525460	NEWHART 3115.00	14703.5
525480	PLANT_X 3115.00	20825.3	525461	NEWHART 6230.00	10848.2
525481	PLANT_X 6230.00	22360.8	525478	PLANTX_TR2 113.200	28454.0
525524	TOLK_EAST 6230.00	26007.8	525480	PLANT_X 3115.00	26772.8
525531	TOLK_WEST 6230.00	26007.8	525481	PLANT_X 6230.00	23651.2
525543	TOLK_TAP 6230.00	26007.8	525524	TOLK_EAST 6230.00	26806.3
525635	LAMB_CNTY 269.000	5813.5	525531	TOLK_WEST 6230.00	26806.3
525636	LAMB_CNTY 3115.00	8503.5	525543	TOLK_TAP 6230.00	26806.3
525637	LAMB_CNTY 6230.00	5443.7	525614	W_LITLFLDTP3115.00	8184.6
525780	FLOYD_CNTY 3115.00	5982.1	525615	W_LITTLFLD 3115.00	7645.2
525816	TUCO_INT2 269.000	4520.5	525636	LAMB_CNTY 3115.00	9627.7
525826	TUCO_INT 269.000	7679.4	525637	LAMB_CNTY 6230.00	5629.6
525828	TUCO_INT 3115.00	19101.9	525780	FLOYD_CNTY 3115.00	6008.5
525830	TUCO_INT 6230.00	18889.1	525816	TUCO_INT2 269.000	4491.6
525832	TUCO_INT 7345.00	9691.7	525826	TUCO_INT 269.000	7792.1
525840	ANTELOPE_1 6230.00	18754.9	525828	TUCO_INT 3115.00	19865.8
526020	HOCKLEY 3115.00	5452.6	525830	TUCO_INT 6230.00	22235.6
526076	STANTON_W 3115.00	9273.4	525832	TUCO_INT 7345.00	12032.5
526161	CARLISLE 6230.00	10799.2	525840	ANTELOPE_1 6230.00	22068.2
526298	LUBBCK_EST 3115.00	14672.4	526076	STANTON_W 3115.00	9443.5
526337	JONES 6230.00	19527.0	526161	CARLISLE 6230.00	13804.9
526434	SUNDOWN 3115.00	10487.5	526298	LUBBCK_EST 3115.00	14935.5
526435	SUNDOWN 6230.00	10710.4	526337	JONES 6230.00	21336.5
526460	AMOCO_SS 6230.00	9358.9	526434	SUNDOWN 3115.00	10532.5
526525	WOLFFORTH 6230.00	13072.4	526435	SUNDOWN 6230.00	11031.3
560011	G14-038-TAP 345.00	10379.0	526460	AMOCO_SS 6230.00	9661.1
562480	G13-027-TAP 230.00	9085.4	526525	WOLFFORTH 6230.00	13754.8
583340	GEN-2012-020230.00	8619.5	560011	G14-038-TAP 345.00	10478.2
584220	GEN-2014-040115.00	11004.9	562480	G13-027-TAP 230.00	9205.2
584640	GEN-2015-022115.00	9911.7	583340	GEN-2012-020230.00	9122.9
			584220	GEN-2014-040115.00	11100.2
			584640	GEN-2015-022115.00	9877.9

4 POWER FACTOR ANALYSIS

4.1 POWER FACTOR ANALYSIS METHODOLOGY

Power Factor Analysis was performed to ensure the studied project meets FERC and SPP power factor requirements for wind farm interconnections. All N-1, three phase stability faults shown in Table 2-1 were analyzed based on power flow analysis (faults are not applied in power flow; instead, post-fault steady-state performance is simulated by tripping relevant transmission facilities that operate to clear the fault). The power factor requirements for the wind farm were determined to maintain the voltage at the POI to the schedule voltage which is the higher of the POI voltage in the provided base case or 1.0 per unit.

The study project wind farm as modeled was turned off for the power factor analysis. The wind farms was replaced by a generator at the high side bus (584220) with the MW of the wind farms at the POI and no var capability. A var generator at the same bus was modeled. The MW and Mvar injections at the POI were recorded for calculating the power factors. The most lagging and most leading power factors among all the disturbances determine the minimum power factor range capability required for the studied wind farm.

Per FERC and SPP requirements, if the power factor needed to maintain the scheduled voltage is less than 0.95 lagging or leading, the requirement is determined on the basis of 0.95 lagging or leading.

If the required power factor at the POI is beyond the capability of the studied wind turbine, the approximate size of the additional capacitors were determined.

4.2 STUDY RESULTS

Table 4-1 summarizes the power factor analysis results. The detailed power factor analysis results for each studied contingency are provided in Appendix C. Per SPP and FERC requirements, the generating facility shall be designed to meet the requirement of 95% lagging (providing vars) and 95% leading (absorbing vars) at the Point of Interconnection.

Table 4-1 Power Factor Analysis Results

Request	Size (MW)	Generator Model	POI	Scenario	Final PF Requirement
GEN-2014-040	319.7	GE 2.3MW (wind)	Castro 115kV (524746)	16WP	0.991 leading
				17SP	0.991 leading
				25SP	0.988 leading

Notes:

Leading is when the generator is absorbing reactive power from the transmission grid. Lagging is when the generator is providing reactive power to the transmission grid.

5 LOW WIND/NO WIND ANALYSIS

5.1 LOW/NO WIND ANALYSIS METHODOLOGY

Low wind/No wind analysis is performed to determine the required shunt reactor size at the study project substation high side bus to bring the MVAr flow into the POI down to approximately zero.

For each studied scenario, the studied wind generator and collector system capacitor banks (none in this study) were switched out of service with the collector system as modeled remaining in service. The resulting reactive power injection into the transmission network coming from the capacitance of the project's transmission lines and collector cables was measured. Then, the required shunt reactor size was calculated to bring the MVAr flow into the POI down to approximately zero.

5.2 STUDY RESULTS

Table 5-1 summaries the Low/No Wind analysis results. It is shown that 23.83 MVAr shunt reactor at the substation high side bus (584220) is required to bring the MVAr flow in the POI down to approximately zero under low/no wind conditions for three studied seasons. This reactor bank size is approximate to be finalized during final facility and collector system design.

Table 5-1 Low/No Wind Analysis Results

Scenario	Reactive Power Injection at POI (MVAr)	Bus 584220 Volt (pu)	Required Shunt Reactor Admittance (MVAr)
16WP	25.10	1.0265	**23.83**
17SP	23.97	1.0030	**23.83**
25SP	23.82	0.9999	**23.83**

6 CONCLUSIONS

A System Impact Restudy for Generator Modification for generation interconnection request GEN-2014-040 (319.7 MW wind farm connected at the Castro County 115 kV bus) was performed.

The objective of this study is to re-evaluate the impact of project GEN-2014-040 on existing and future system performance based on an updated wind farm design (wind turbine-generators and collector system) as specified by the Interconnection Customer. While the previous study was based on a total of 160 Vestas V110 2.0 MW wind turbine-generators, the present study is based on a total of 139 GE 2.3 MW wind-turbine generators.

The study is performed on three system scenarios provided by SPP:

- 2016 Winter Peak Case
- 2017 Summer Peak Case
- 2025 Summer Peak Case

The scope of the study included stability analysis, short-circuit analysis, power factor evaluation and low-wind/no-wind analysis. The following is a summary of study results.

Results of the Stability Analysis show no stability problems or voltage violations for all studied disturbances on all three seasons. All the simulation results are summarized in Table 2-2, Table 2-3 and Table 2-4. Based on the results of the stability analysis, the conclusion is that the proposed GEN-2014-040 will not cause stability problems.

System short-circuit current levels at up to five buses away from the point of interconnection were calculated and tabulated for SPP's reference.

Power Factor Analysis was performed to check whether the studied project meets FERC and SPP power factor requirements for wind farm interconnections. The wind farm will be required to meet the 95% lagging (injecting MVAr into the grid) and 95% leading (absorbing MVAr from the grid) power factor requirements at the Point of Interconnection.

The Low/No Wind analysis shows that 23.83 MVAr of shunt reactance is required at the POI to bring the MVAr flow at the POI down to approximately zero under low/no wind conditions for all three studied seasons. The reactor bank size is approximate and the final size will be determined in the final facility and collector system design.

The results of this analysis are based on available data and assumptions made at the time of conducting this study. If any of the data and/or assumptions made in developing the study model change, the results provided in this report may not apply.

APPENDIX A SOUTHWEST POWER POOL DISTURBANCE PERFORMANCE CRITERIA REQUIREMENTS

OVERVIEW

These Disturbance Performance Requirements ("Requirements") shall be applicable to the Bulk Electric System within the Southwest Power Pool Planning Area. Utilization of these Requirements applies to all registered entities within the Southwest Power Pool Planning Area. These Requirements shall not be applicable to facilities that are not part of Bulk Electric System. More stringent Requirements are at the sole discretion of each Transmission Owner.

Transient and dynamic stability assessments are generally performed to assure adequate avoidance of loss of generator synchronism and prevention of system voltage collapse within the first 20 seconds after a system disturbance. These Requirements provide a basis for evaluating the system response during the initial transient period following a disturbance on the Bulk Electric System by establishing minimum requirements for machine rotor angle damping and transient voltage recovery.

ROTOR ANGLE DAMPING REQUIREMENT

Machine Rotor Angles shall exhibit well damped angular oscillations [as defined below] and acceptable power swings following a disturbance on the Bulk Electric System for all NERC Category A, B and C events.

Well damped angular oscillations shall meet one of the following two requirements when calculated directly from the rotor angle:

1. Successive Positive Peak Ratio (SPPR) must be less than or equal to 0.95 where SPPR is calculated as follows:

$$\text{SPPR} = \frac{\text{Peak Rotor Angle of } 2^{nd} \text{ Positive Swing Peak}}{\text{Peak Rotor Angle of } 1^{st} \text{ Positive Swing Peak}} \leq 0.95$$

   -or- Damping Factor % = (1 – SPPR) x 100% ≥ 5%

   The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

   Damping Ratio ≥ 0.0081633

2. Successive Positive Peak Ratio Five (SPPR5) must be less than or equal to 0.774 where SPPR5 is calculated as follows:

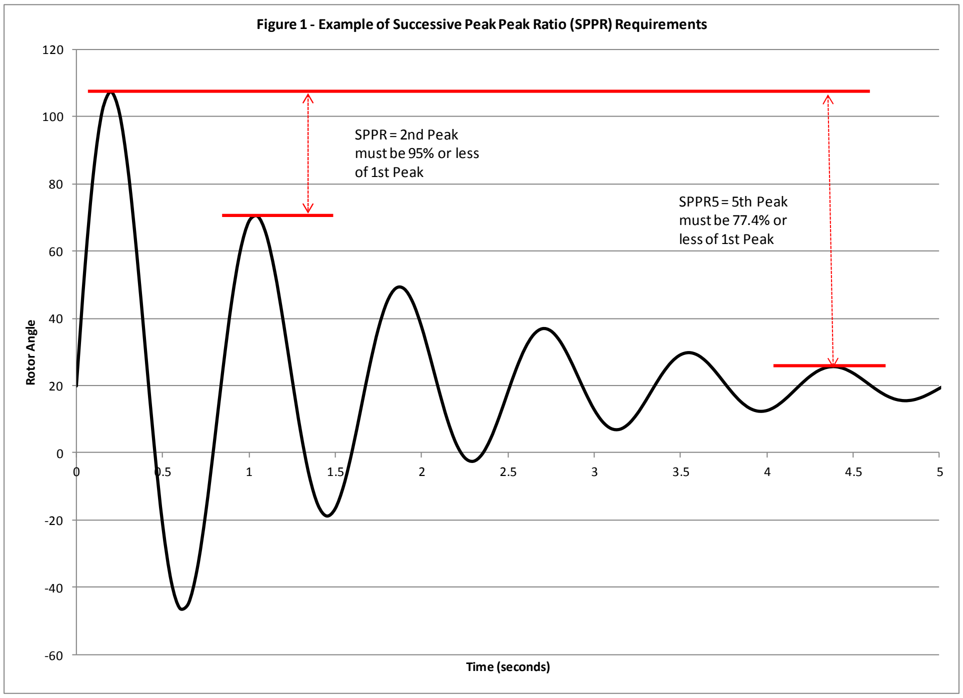
$$\text{SPPR5} = \frac{\text{Peak Rotor Angle of } 5^{th} \text{ Positive Swing Peak}}{\text{Peak Rotor Angle of } 1^{st} \text{ Positive Swing Peak}} \leq 0.774$$

   -or- Damping Factor % = (1 – SPPR5) x 100% ≥ 22.6%

   The machine rotor angle damping ratio may be determined by appropriate modal analysis (i.e. Prony Analysis) where the following equivalent requirement must be met:

Damping Ratio ≥ 0.0081633

Qualitatively, these Requirements are shown in Figure 1 below.



TRANSIENT VOLTAGE RECOVERY REQUIREMENT

Any time after a disturbance is cleared; bus voltages on the Bulk Electric System shall not swing outside of the bandwidth of 0.70 per unit to 1.20 per unit 2.5 sec after the fault is cleared. All post-transient voltages must fall between the 0.90 pu and 1.1 pu range at the end of the simulations.

Qualitatively, this Requirement is shown in Figure 2 below.

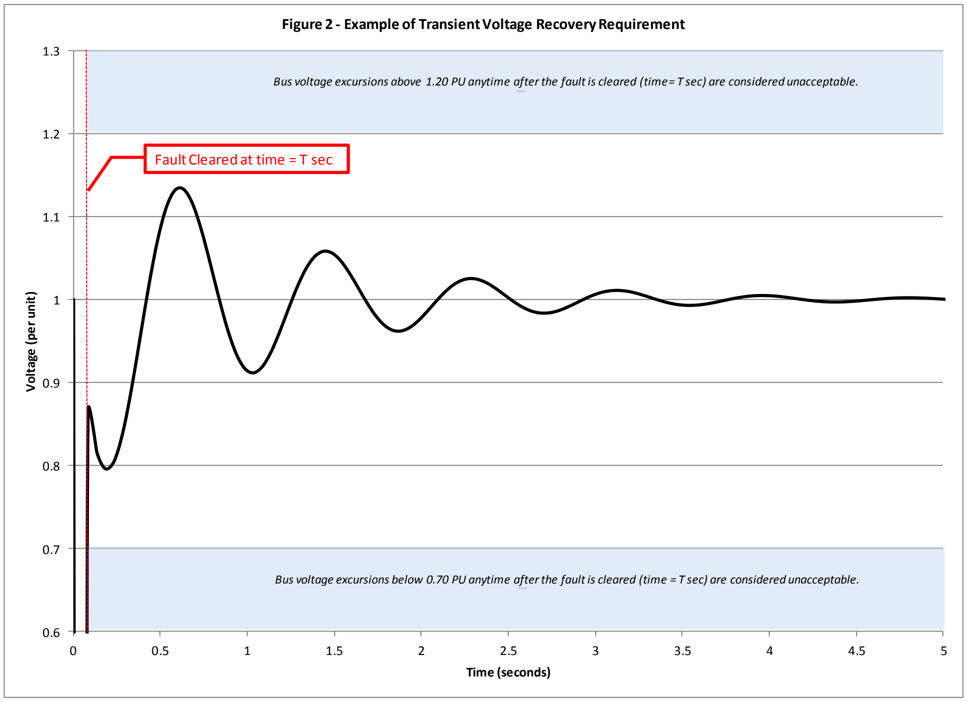


Figure 2 - Example of Transient Voltage Recovery Requirement
Bus voltage excursions above 1.20 PU anytime after the fault is cleared (time= T sec) are considered unacceptable.
Fault Cleared at time = T sec
Bus voltage excursions below 0.70 PU anytime after the fault is cleared (time = T sec) are considered unacceptable.
Voltage (per unit)
Time (seconds)

APPENDIX B SIMULATION PLOTS FOR STABILITY ANALYSIS

APPENDIX C POWER FACTOR ANALYSIS RESULTS

All the contingency numbers shown in this appendix match the fault numbers shown in Table 4-1.

C.1 GEN-2014-040 2016 Winter Peak Case

The GEN-2014-040 POI voltage is 1.0209 pu in the provided 2016 winter peak case. Therefore, the power factor requirements for the wind farm were determined to maintain the voltage at the POI to this value. The lowest lagging and leading power factors are highlighted in red in the table below.

Outage No.		MW	Mvar	PF	
System Intact	0	-311.3	40.8	0.992	leading
Contingency	1	-311.4	38.6	0.992	leading
Contingency	2	-311.4	32.7	0.995	leading
Contingency	3	-311.5	38.3	0.993	leading
Contingency	4	-311.3	37.8	0.993	leading
Contingency	5	-311.3	40.7	0.992	leading
Contingency	6	-311.3	40.6	0.992	leading
Contingency	7	-311.3	40.7	0.992	leading
Contingency	8	-311.3	40.6	0.992	leading
Contingency	9	-311.4	29.9	0.995	leading
Contingency	10	-311.3	40.6	0.992	leading
Contingency	11	-311.3	39.3	0.992	leading
Contingency	12	-311.3	39.7	0.992	leading
Contingency	14	-311.3	40.7	0.992	leading
Contingency	15	-311.3	38.3	0.993	leading
Contingency	16	-311.3	40.2	0.992	leading
Contingency	17	-311.3	40.2	0.992	leading
Contingency	21	-311.4	32.7	0.995	leading
Contingency	22	-311.4	32.7	0.995	leading
Contingency	24	-311.3	37.9	0.993	leading
Contingency	25	-311.3	36.7	0.993	leading
Contingency	26	-311.4	36.7	0.993	leading
Contingency	27	-311.3	40.7	0.992	leading
Contingency	28	-311.3	40.2	0.992	leading
Contingency	29	-311.3	40.3	0.992	leading
Contingency	30	-311.3	39.6	0.992	leading
Contingency	31	-311.3	42.3	**0.991**	leading
Contingency	32	-311.3	39.8	0.992	leading
Contingency	33	-311.3	40.2	0.992	leading
Contingency	34	-311.3	42.7	**0.991**	leading
Contingency	37	-311.4	32.7	0.995	leading

Outage No.		MW	Mvar	PF	
Contingency	38	-311.4	32.7	0.995	leading
Contingency	39	-311.5	38.3	0.993	leading

C.2 GEN-2014-040 2017 Summer Peak Case

The GEN-2014-040 POI voltage is 1.0121 pu in the provided 2017 summer peak case. Therefore, the power factor requirements for the wind farm were determined to maintain the voltage at the POI to this value. The lowest lagging and leading power factors are highlighted in red in the table below.

Outage No.		MW	Mvar	PF	
System Intact	0	-311.3	29.5	0.996	leading
Contingency	1	-311.3	30.8	0.995	leading
Contingency	2	-311.2	38.4	0.992	leading
Contingency	3	-311.4	13.4	0.999	leading
Contingency	4	-311.3	23.9	0.997	leading
Contingency	5	-311.3	29.3	0.996	leading
Contingency	6	-311.3	31.7	0.995	leading
Contingency	7	-311.3	29.4	0.996	leading
Contingency	8	-311.3	27.6	0.996	leading
Contingency	9	-311.4	10.7	0.999	leading
Contingency	10	-311.3	28.2	0.996	leading
Contingency	11	-311.3	24.2	0.997	leading
Contingency	12	-311.3	27.6	0.996	leading
Contingency	14	-311.2	35.1	0.994	leading
Contingency	15	-311.3	29.8	0.995	leading
Contingency	16	-311.3	22.8	0.997	leading
Contingency	17	-311.3	24.5	0.997	leading
Contingency	21	-311.2	38.4	0.992	leading
Contingency	22	-311.2	38.4	0.992	leading
Contingency	24	-311.3	23.8	0.997	leading
Contingency	25	-311.4	18.8	0.998	leading
Contingency	26	-311.3	26	0.997	leading
Contingency	27	-311.3	29.4	0.996	leading
Contingency	28	-311.3	27.8	0.996	leading
Contingency	29	-311.3	31	0.995	leading
Contingency	30	-311.3	28.7	0.996	leading
Contingency	31	-311.4	17.9	0.998	leading
Contingency	32	-311.3	28.1	0.996	leading
Contingency	33	-311.3	26.7	0.996	leading
Contingency	34	-311.2	43.1	**0.991**	leading
Contingency	37	-311.2	38.4	0.992	leading
Contingency	38	-311.2	38.4	0.992	leading
Contingency	39	-311.4	13.4	0.999	leading

C.3 GEN-2014-040 2025 Summer Peak Case

The GEN-2014-040 POI voltage is 1.0114 pu in the provided 2025 summer peak case. Therefore, the power factor requirements for the wind farm were determined to maintain the voltage at the POI to this value. The lowest lagging and leading power factors are highlighted in red in the table below.

Outage No.		MW	Mvar	PF	
System Intact	0	-311.3	28.6	0.996	leading
Contingency	1	-311.4	14	0.999	leading
Contingency	2	-311.2	47.9	**0.988**	leading
Contingency	3	-311.4	14.4	0.999	leading
Contingency	4	-311.4	5.8	1	leading
Contingency	5	-311.3	28.4	0.996	leading
Contingency	6	-311.2	34.2	0.994	leading
Contingency	7	-311.3	28.5	0.996	leading
Contingency	8	-311.2	26.2	0.996	leading
Contingency	9	-311.5	13.2	0.999	leading
Contingency	10	-311.3	27.9	0.996	leading
Contingency	11	-311.3	22.7	0.997	leading
Contingency	12	-311.3	26.8	0.996	leading
Contingency	13	-311.3	28	0.996	leading
Contingency	14	-311.2	36.3	0.993	leading
Contingency	15	-311.3	29.3	0.996	leading
Contingency	16	-311.4	18.5	0.998	leading
Contingency	17	-311.3	22.9	0.997	leading
Contingency	21	-311.2	47.9	**0.988**	leading
Contingency	22	-311.2	47.9	**0.988**	leading
Contingency	24	-311.4	21.6	0.998	leading
Contingency	25	-311.5	13.8	0.999	leading
Contingency	26	-311.3	26.9	0.996	leading
Contingency	27	-311.3	28.6	0.996	leading
Contingency	28	-311.3	28.3	0.996	leading
Contingency	29	-311.3	29.2	0.996	leading
Contingency	30	-311.3	28	0.996	leading
Contingency	31	-311.5	11.4	0.999	leading
Contingency	32	-311.3	27.1	0.996	leading
Contingency	33	-311.3	24.8	0.997	leading
Contingency	34	-311	44.9	0.99	leading
Contingency	37	-311.2	47.9	**0.988**	leading
Contingency	38	-311.2	47.9	**0.988**	leading
Contingency	39	-311.4	14.4	0.999	leading

APPENDIX D PARAMETERS FOR GENERATORS IN THE PROPOSED PROJECT