Southwest Power Pool

GEN-2010-001 Impact Restudy for Generator Modification (Turbine Change)

SPP Generator Interconnection Studies

GEN-2010-001

December 2013

Executive Summary

The GEN-2010-001 interconnection customer has requested a system impact restudy to determine the effects of changing wind turbine generators from the previously studied Vestas V100 VCSS 2.0 MW wind turbine generators to the GE 1.85-87 (1.85MW, 87meter diameter rotor) wind turbine generators. Mitsubishi Electric Power Products, Inc. (MEPPI) was commissioned to perform this restudy and its report of the results is attached.

In this restudy the project uses one hundred sixty-two (162) GE 1.85-87 wind turbine generators for an aggregate power of 299.7MW. The point of interconnection (POI) for GEN-2010-001 is at the proposed Beaver County 345 kV Substation in Beaver County, OK. The interconnection customer has provided documentation that shows the GE 1.85-87 wind turbine generators will have a reactive capability of 0.95 lagging (providing VARS) and 0.95 leading (absorbing VARS) power factor.

The restudy showed that no stability problems were found during the summer and the winter peak conditions as a result of changing to the GE 1.85MW 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 in this study. The facility will be required to maintain a 95% lagging (providing VARs) and 95% leading (absorbing VARs) power factor at the point of interconnection. Since the wind generators are capable of 0.95 lagging/0.95 leading at the generator terminal, additional capacitor banks will be required to meet the capacitive requirement. Approximately 12.7 MVAR of additional inductive reactive support is required in order to compensate for the collector system and transmission line charging effects at the POI when GEN-2010-001 is at low wind or no wind conditions. As an option to its wind turbine generators GE provides a Windfree Reactive Power System that provides reactive power even with no wind. This option may eliminate the need for external reactor banks.

With the assumptions outlined in this report and with all the required network upgrades from the GEN-2010-001 GIA in place, GEN-2010-001 with the GE 1.85-87 wind turbine generators should be able to reliably interconnect to the SPP transmission grid.

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 by the Customer.

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Southwest Power Pool, Inc. (SPP)

GEN-2010-001 System Impact Restudy

Final Report

PXE-0761
Revision #00

December 2013

Submitted By:
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Title: **GEN-2010-001 System Impact Restudy: Final Report for PXE-0761**
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EXECUTIVE SUMMARY

SPP requested a Definitive Interconnection System Impact Study (DISIS). The DISIS required a Stability Analysis and Power Factor Analysis detailing the impacts of the interconnecting projects as shown in Table ES-1.

Table ES-1: Interconnection Projects Evaluated

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2010-001	300	GE 1.85MW (162 machines for a total of 299.7MW)	Tap on Hitchland to Woodward 345kV line (Beaver County 580500)

SUMMARY OF STABILITY ANALYSIS

For the 2014 Winter Peak case, the Stability Analysis determined that there was no wind turbine tripping that occurs from interconnecting GEN-2010-001 at 100% output. There were no low voltage recovery or stability issues observed for the winter peak conditions.

For the 2015 Summer Peak case, the Stability Analysis determined that there was no wind turbine tripping that occurs from interconnecting GEN-2010-001 at 100% output. There were no low voltage recovery or stability issues observed for the summer peak conditions.

For the 2024 Future Summer Peak case, the Stability Analysis determined that there was no wind turbine tripping that occurs from interconnecting GEN-2010-001 at 100% output. There were no low voltage recovery or stability issues observed for the future summer peak conditions.

SUMMARY OF POWER FACTOR ANALYSIS

The Power Factor Analysis shows that GEN-2010-001 has a power factor range of 0.860 lagging (supplying) to 0.928 leading (consuming). A total of 12.7 MVAR of additional inductive support would be required in order to compensate for the collector system and lead line charging when GEN-2010-001 is off-line such that the VAR flow at the POI is zero.

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SECTION 1: OBJECTIVES

The objective of this report is to provide Southwest Power Pool, Inc. (SPP) with the deliverables for the "GEN-2010-001 System Impact Restudy." SPP requested an Interconnection System Impact Study for GEN-2010-001, which requires a Stability Analysis, a Power Factor Analysis and an Impact Study Report.

SECTION 2: BACKGROUND

The Siemens Power Technologies, Inc. PSS/E power system simulation program Version 32.2.0 was used for this study. SPP provided the stability database cases for summer peak and winter peak seasons and a list of contingencies to be examined. The model includes the study project and the previously queued projects as listed in Table 2-1 and Table 2-2, respectively. Refer to Appendix A for the steady state and dynamic model data for the study projects. A power flow one-line diagram of GEN-2010-001 interconnection project is shown in Figure 2-1.

The Stability Analysis will determine the impacts of the new interconnecting project on the stability and voltage recovery of the nearby system and the ability of the interconnecting project to meet FERC Order 661A. If problems with stability or voltage recovery are identified, the need for reactive compensation or system upgrades will be investigated. Three-phase and single-phase faults will be examined as listed in Table 2-3.

The Power Factor Analysis will determine the power factor at the point of interconnection for the wind interconnection project for pre-contingency and post-contingency conditions. Table 2-3 lists the contingencies developed from the three-phase fault definitions provided in the Group's interconnection impact study request. Additionally, an analysis of the amount of reactive compensation such that the VAR flow at the POI was zero when GEN-2010-001 is off-line was performed.

Table 2-1
Interconnection Project Evaluated

Request	Size (MW)	Turbine Model	Point of Interconnection (POI)
GEN-2010-001	300	GE 1.85MW (162 machines for a total of 299.7MW)	Tap on Hitchland to Woodward 345kV line (Beaver County 580500)

Table 2-2
Previously Queued Nearby Interconnection Projects Included

Request	Size (MW)	Turbine Model	Point of Interconnection (POI)
GEN-2002-008	240	GE 1.5MW	Hitchland 345kV (523097)
GEN-2002-009	80	Suzlon S88 2.1MW	Hansford 115kV (523195)
GEN-2003-020	160	GE 1.5 MW	Carson Co. 115kV (523924)
GEN-2006-020S	20	DeWind 2.0MW	Hitchland – Sherman Tap 115kV (560200)
GEN-2006-044	370	DeWind 2.0MW	Hitchland 345kV (523097)
GEN-2007-046	199.5	GE 1.5MW	Hitchland 115kV (523093)
GEN-2008-047	300	GE 1.5MW	Tap (580500) on Hitchland to Woodward 345kV line
GEN-2008-124T	42	GE1.5MW	TC-Keyes 69kV (523032)
GEN-2010-014	358.8	Siemens SWT 2.3MW	Hitchland 345kV (523097)

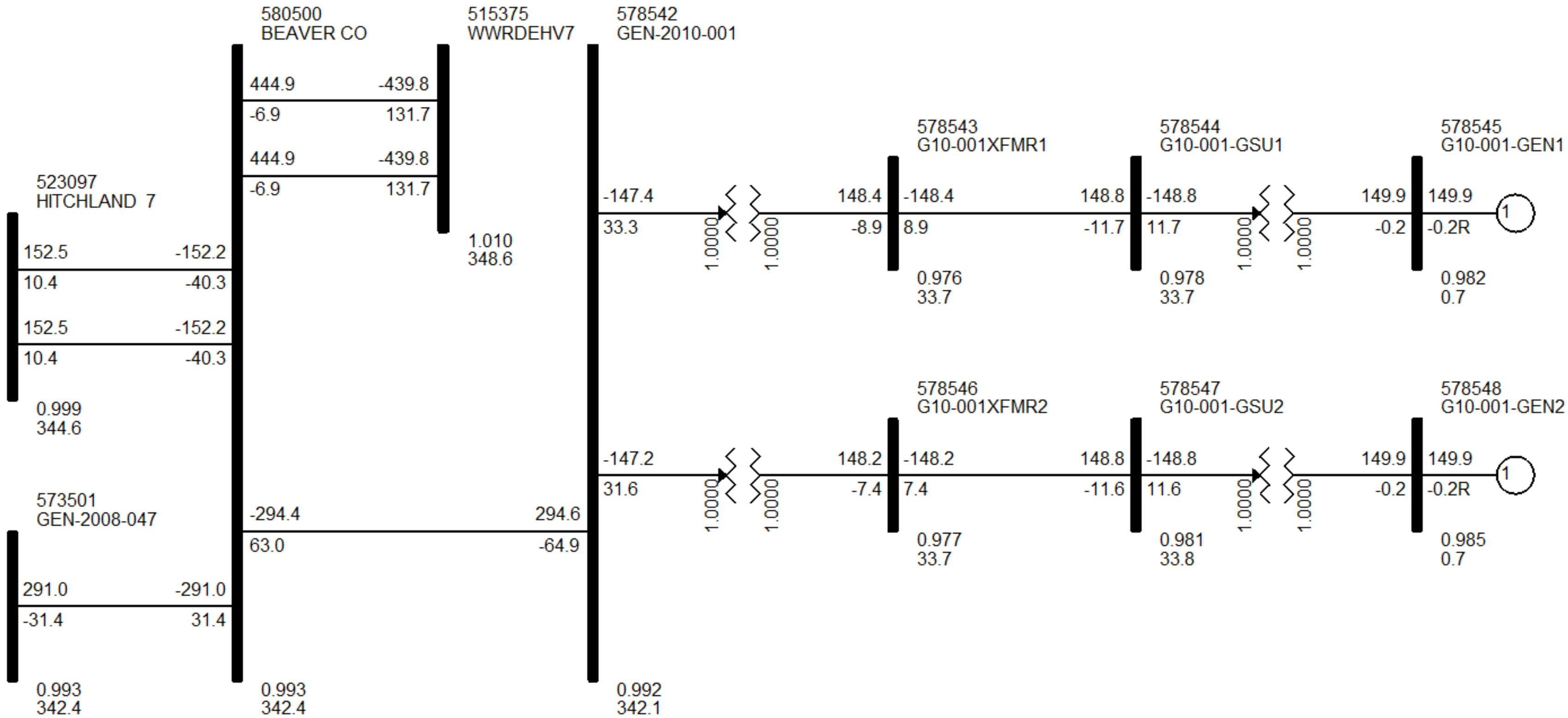

Figure 2-1. Power flow one-line diagram for interconnection project GEN-2010-001 (299.7 MW).

Table 2-3
Case List with Contingency Description

Cont. No.	Cont. Name	Description
1	FLT01-3PH	3 phase fault on the Beaver County (580500) to Hitchland (523097) 345kV, ckt 1, near Beaver County. a. Apply fault at the Beaver County 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
2	FLT02-1PH	*Single phase fault and sequence like previous*
3	FLT03-3PH	3 phase fault on the Beaver County (580500) to Woodward (515375) 345kV, ckt 1, near Beaver County. a. Apply fault at the Beaver County 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
4	FLT04-1PH	*Single phase fault and sequence like previous*
5	FLT05-3PH	3 phase fault on the Hitchland (523097) to Finney (523853) 345kV, ckt 1, near Hitchland. a. Apply fault at the Hitchland 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
6	FLT06-1PH	*Single phase fault and sequence like previous*
7	FLT07-3PH	3 phase fault on the Hitchland (523097) to Potter County (523961) 345kV, ckt 1, near Hitchland. a. Apply fault at the Hitchland 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
8	FLT08-3PH	*Single phase fault and sequence like previous*
9	FLT09-3PH	3 phase fault on the Woodward (515375) to Tatonga (515407) 345kV, ckt 1, near Woodward. a. Apply fault at the Woodward 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
10	FLT10-1PH	*Single phase fault and sequence like previous*
11	FLT11-3PH	3 phase fault on the Woodward (515375) to Border (515458) 345kV, ckt 1, near Woodward. a. Apply fault at the Woodward 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
12	FLT12-1PH	*Single phase fault and sequence like previous*
13	FLT13-3PH (2014 Winter/2015 Summer only)	3 phase fault on the Woodward (515375) to Thistle (539801) 345kV, ckt 1, near Woodward. a. Apply fault at the Woodward 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
14	FLT14-1PH	*Single phase fault and sequence like previous*
15	FLT15-3PH	3 phase fault on the Border (515458) to Tuco Int (525832) 345kV, ckt 1, near Border. a. Apply fault at the Border 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 2-3 (Continued)
Case List with Contingency Description

Cont. No.	Cont. Name	Description
16	FLT16-1PH	*Single phase fault and sequence like previous*
17	FLT17-3PH	3 phase fault on the Finney (523853) to Holcomb (531449) 345kV, ckt 1, near Finney. a. Apply fault at the Finney 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
18	FLT18-1PH	*Single phase fault and sequence like previous*
19	FLT19-3PH	3 phase fault on the Finney (523853) to Lamar (599950) 345kV, ckt 1, near Finney. a. Apply fault at the Finney 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
20	FLT20-1PH	*Single phase fault and sequence like previous*
21	FLT21-3PH	3 phase fault on the Hitchland (523095) to Ochiltree (523155) 230kV, ckt 1, near Hitchland. a. Apply fault at the Hitchland 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
22	FLT22-1PH	*Single phase fault and sequence like previous*
23	FLT23-3PH	3 phase fault on the Hitchland (523095) to Moore County (523309) 230kV, ckt 1, near Hitchland. a. Apply fault at the Hitchland 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
24	FLT24-1PH	*Single phase fault and sequence like previous*
25	FLT25-3PH	3 phase fault on the Moore County (523309) to Potter County (523959) 230kV, ckt 1, near Moore County. a. Apply fault at the Moore County 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
26	FLT26-1PH	*Single phase fault and sequence like previous*
27	FLT27-3PH	3 phase fault on the Woodward (515376) to Woodward (514785) 138kV, ckt 1, near Woodward (515376). a. Apply fault at the Woodward (515376) 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
28	FLT28-1PH	*Single phase fault and sequence like previous*
29	FLT29-3PH	3 phase fault on the Woodward (515376) to Iodine (514796) 138kV, ckt 1, near Woodward. a. Apply fault at the Woodward 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
30	FLT30-1PH	*Single phase fault and sequence like previous*
31	FLT31-3PH	3 phase fault on the Woodward (515376) to Keenan (514000) 138kV, ckt 1, near Woodward. a. Apply fault at the Woodward 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

Table 2-3 (Continued)
Case List with Contingency Description

Cont. No.	Cont. Name	Description
32	FLT32-1PH	*Single phase fault and sequence like previous*
33	FLT33-3PH	3 phase fault on the Woodward (515376) to OU Spirit (515398) 138kV, ckt 1, near Woodward. a. Apply fault at the Woodward 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
34	FLT34-1PH	*Single phase fault and sequence like previous*
35	FLT35-3PH	3 phase fault on the Hitchland (523093) to Texas County (523090) 115kV, ckt 1, near Hitchland. a. Apply fault at the Hitchland 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
36	FLT36-1PH	*Single phase fault and sequence like previous*
37	FLT37-3PH	3 phase fault on the Hitchland (523093) to DWS Frisco (523160) 115kV, ckt 1, near Hitchland. a. Apply fault at the Hitchland 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
38	FLT38-1PH	*Single phase fault and sequence like previous*
39	FLT39-3PH	3 phase fault on the Hitchland (523093) to Hansford (523195) 115kV, ckt 1, near Hitchland. a. Apply fault at the Hitchland 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
40	FLT40-1PH	*Single phase fault and sequence like previous*
41	FLT41-3PH	3 phase fault on the Hitchland 345kV (523097) to the Hitchland 230kV (523095)/13.2kV (523091) transformer near the 345kV bus. a. Apply fault at the Hitchland 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
42	FLT42-3PH	3 phase fault on the Woodward 345kV (515375) to the Woodward 138kV (515376)/13.8kV (515799) transformer near the 345kV bus. a. Apply fault at the Woodward 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
43	FLT43-3PH	3 phase fault on the Potter County 345kV (523961) to the Potter County 230kV (523959)/13.2kV (523957) transformer near the 345kV bus. a. Apply fault at the Potter County 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
44	FLT44-3PH	3 phase fault on the Ochiltree 230kV (523155) to the Ochiltree 115kV (523154)/13.2kV (523151) transformer near the 230kV bus. a. Apply fault at the Ochiltree 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
45	FLT45-3PH	3 phase fault on the Moore County 230kV (523309) to the Moore County 115kV (523308)/13.2kV (523302) transformer near the 230kV bus. a. Apply fault at the Moore County 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.

Table 2-3 (Continued)
Case List with Contingency Description

Cont. No.	Cont. Name	Description
46	FLT46-3PH	3 phase **double circuit** fault on Beaver County (580500) to Hitchland (523097) 345kV line, ckt1&2, near Beaver County. a. Apply fault at the Beaver County 345kV bus. b. Clear fault after 5 cycles by tripping the faulted lines. 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.
47	FLT47-3PH	3 phase **double circuit** fault on Beaver County (580500) to Woodward (515375) 345kV line, ckt1&2, near Beaver County. a. Apply fault at the Beaver County 345kV bus. b. Clear fault after 5 cycles by tripping the faulted lines. 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.
48	FLT48-3PH (2014 Winter/2015 Summer only)	3 phase **double circuit** fault on Woodward (515375) to Thistle (539801) 345kV line, ckt1&2, near Woodward. a. Apply fault at the Woodward 345kV bus. b. Clear fault after 5 cycles by tripping the faulted lines. 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.

SECTION 3: STABILITY ANALYSIS

The objective of the stability analysis was to determine the impacts of the new wind farms on the stability and voltage recovery on the SPP transmission system. If problems with stability or voltage recovery were identified the need for reactive compensation or system upgrades were investigated.

Approach

The 2014 winter peak, 2015 summer peak, and the 2024 summer peak power flows provided by SPP were examined prior to the Stability Analysis to ensure they contained the proposed study project (GEN-2010-001) modeled at 100% of the nameplate rating and any previously queued projects listed in Table 2-2. There was no suspect power flow data in the study area. The dynamic datasets were also verified and stable initial system conditions (i.e., “flat lines”) were achieved. Three-phase and single line-to-ground faults listed in Table 2-3 were examined. Single-phase fault impedances were calculated to result in a voltage of approximately 60% of the pre-fault voltage. Refer to Table 3-1 for a list of the calculated single-phase fault impedances used for this analysis.

Table 3-1
Calculated Single-Phase Fault Impedances

Ref. No.	Casename	Single-Phase Fault Impedance (MVA)		
		2014 Winter Peak	2015 Summer Peak	2024 Future Summer Peak
2	FLT02-1PH	4437.5	4437.5	4640.6
4	FLT04-1PH	4437.5	4437.5	4640.6
6	FLT06-1PH	4843.8	4843.8	5046.9
8	FLT08-1PH	4843.8	4843.8	5046.9
10	FLT10-1PH	6062.5	6025.5	8093.8
12	FLT12-1PH	6062.5	6025.5	8093.8
14	FLT14-1PH	6062.5	6025.5	8093.8
16	FLT16-1PH	1750.0	1750.0	1875.0
18	FLT18-1PH	4031.3	4031.3	4234.4
20	FLT20-1PH	4031.3	4031.3	4234.4
22	FLT22-1PH	3218.8	3218.8	3218.8
24	FLT24-1PH	3218.8	3218.8	3218.8
26	FLT26-1PH	1750.0	1625.0	1625.0
28	FLT28-1PH	3828.1	4031.3	4234.4
30	FLT30-1PH	3828.1	4031.3	4234.4
32	FLT32-1PH	3828.1	4031.3	4234.4
34	FLT34-1PH	3828.1	4031.3	4234.4
36	FLT36-1PH	1750.0	1750.0	1625.0
38	FLT38-1PH	1750.0	1750.0	1625.0
40	FLT40-1PH	1750.0	1750.0	1625.0

Bus voltages and previously queued generation in the study area were monitored in addition to the bus voltages in the following areas:

- 520 AEPW
- 524 OKGE
- 525 WFEC
- 526 SPS
- 531 MIDW
- 534 SUNC
- 536 WERE

The results of the analysis determined if reactive compensation or system upgrades were required to obtain acceptable system performance. If additional reactive compensation was required, the size, type, and location were determined. The proposed reactive reinforcements would ensure the wind farm meets FERC Order 661A low voltage requirements and return the wind farm to its pre-disturbance operating voltage. If the results indicated the need for fast responding reactive support, dynamic support such as an SVC or STATCOM was investigated. If tripping of the prior queued projects was observed during the stability analysis (for under/over voltage or under/over frequency) the simulations were re-ran with the prior queued project's voltage and frequency tripping disabled.

Results

The Stability Analysis determined that there was no wind turbine tripping that occurs from interconnecting GEN-2010-001 at 100% output. Refer to Table 3-2 for a summary of the Stability Analysis results for the cases listed in Table 2-3.

2014 Winter Peak Summary

For the winter peak case, the Stability Analysis determined that there was no wind turbine tripping that occurs from interconnecting GEN-2010-001 at 100% output. There were no low voltage recovery or stability issues observed for the winter peak conditions.

Refer to Figure 3-1 for a representative response plot of select bus voltages during Contingency #5 (FLT5-3PH) for winter peak conditions without mitigation.

2015 Summer Peak Summary

For the summer peak case, the Stability Analysis determined that there was no wind turbine tripping that occurs from interconnecting GEN-2010-001 at 100% output. There were no low voltage recovery or stability issues observed for the summer peak conditions.

Refer to Figure 3-2 for a representative response plot of select bus voltages during Contingency #5 (FLT5-3PH) for summer peak conditions without mitigation

2024 Future Summer Peak Summary

For the future summer peak case, the Stability Analysis determined that there was no wind turbine tripping that occurs from interconnecting GEN-2010-001 at 100% output. There were no low voltage recovery or stability issues observed for the future summer peak conditions.

Refer to Figure 3-3 for a representative response plot of select bus voltages during Contingency #5 (FLT5-3PH) for future summer peak conditions without mitigation.

Refer to Appendix B, C, and D for a complete list of plots for all contingencies for 2014 winter peak, 2015 summer peak, and 2024 summer peak conditions, respectively.

Table 3-2
Stability Analysis Summary of Results

Ref. No.	Casename	2014 Winter Peak		2015 Summer Peak		2024 Future Summer Peak	
		Stable?	Acceptable Voltages?	Stable?	Acceptable Voltages?	Stable?	Acceptable Voltages?
1	FLT01-3PH	YES	YES	YES	YES	YES	YES
2	FLT02-1PH	YES	YES	YES	YES	YES	YES
3	FLT03-3PH	YES	YES	YES	YES	YES	YES
4	FLT04-1PH	YES	YES	YES	YES	YES	YES
5	FLT05-3PH	YES	YES	YES	YES	YES	YES
6	FLT06-1PH	YES	YES	YES	YES	YES	YES
7	FLT07-3PH	YES	YES	YES	YES	YES	YES
8	FLT08-1PH	YES	YES	YES	YES	YES	YES
9	FLT09-3PH	YES	YES	YES	YES	YES	YES
10	FLT10-1PH	YES	YES	YES	YES	YES	YES
11	FLT11-3PH	YES	YES	YES	YES	YES	YES
12	FLT12-3PH	YES	YES	YES	YES	YES	YES
13	FLT13-1PH	YES	YES	YES	YES	YES	YES
14	FLT14-3PH	YES	YES	YES	YES	YES	YES
15	FLT15-1PH	YES	YES	YES	YES	YES	YES
16	FLT16-3PH	YES	YES	YES	YES	YES	YES
17	FLT17-1PH	YES	YES	YES	YES	YES	YES
18	FLT18-3PH	YES	YES	YES	YES	YES	YES
19	FLT19-1PH	YES	YES	YES	YES	YES	YES
20	FLT20-3PH	YES	YES	YES	YES	YES	YES
21	FLT21-3PH	YES	YES	YES	YES	YES	YES
22	FLT22-1PH	YES	YES	YES	YES	YES	YES
23	FLT23-3PH	YES	YES	YES	YES	YES	YES
24	FLT24-1PH	YES	YES	YES	YES	YES	YES
25	FLT25-3PH	YES	YES	YES	YES	YES	YES
26	FLT26-1PH	YES	YES	YES	YES	YES	YES

Table 3-2 (Continued)
Stability Analysis Summary of Results

Ref. No.	Casename	2014 Winter Peak		2015 Summer Peak		2024 Future Summer Peak	
		Stable?	Acceptable Voltages?	Stable?	Acceptable Voltages?	Stable?	Acceptable Voltages?
27	FLT27-3PH	YES	YES	YES	YES	YES	YES
28	FLT28-1PH	YES	YES	YES	YES	YES	YES
29	FLT29-3PH	YES	YES	YES	YES	YES	YES
30	FLT30-1PH	YES	YES	YES	YES	YES	YES
31	FLT31-3PH	YES	YES	YES	YES	YES	YES
32	FLT32-1PH	YES	YES	YES	YES	YES	YES
33	FLT33-3PH	YES	YES	YES	YES	YES	YES
34	FLT34-1PH	YES	YES	YES	YES	YES	YES
35	FLT35-3PH	YES	YES	YES	YES	YES	YES
36	FLT36-1PH	YES	YES	YES	YES	YES	YES
37	FLT37-3PH	YES	YES	YES	YES	YES	YES
38	FLT38-1PH	YES	YES	YES	YES	YES	YES
39	FLT39-3PH	YES	YES	YES	YES	YES	YES
40	FLT40-1PH	YES	YES	YES	YES	YES	YES
41	FLT41-3PH	YES	YES	YES	YES	YES	YES
42	FLT42-3PH	YES	YES	YES	YES	YES	YES
43	FLT43-3PH	YES	YES	YES	YES	YES	YES
44	FLT44-3PH	YES	YES	YES	YES	YES	YES
45	FLT45-3PH	YES	YES	YES	YES	YES	YES
46	FLT46-3PH	YES	YES	YES	YES	YES	YES
47	FLT47-3PH	YES	YES	YES	YES	YES	YES
48	FLT48-3PH	YES	YES	YES	YES	N/A	N/A

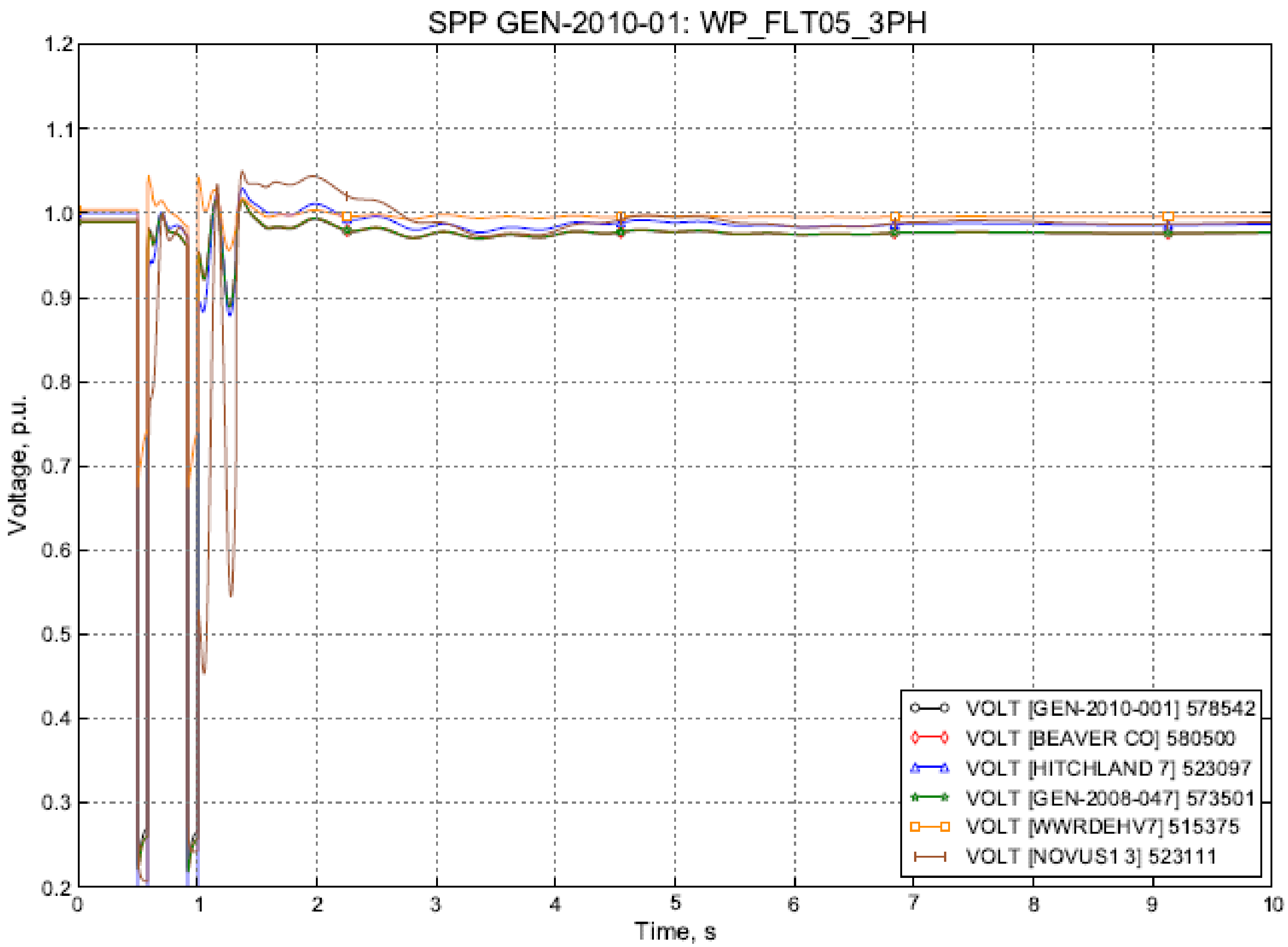

Figure 3-1. Response of select bus voltages during Contingency #5 (FLT05-3PH) for winter peak conditions.

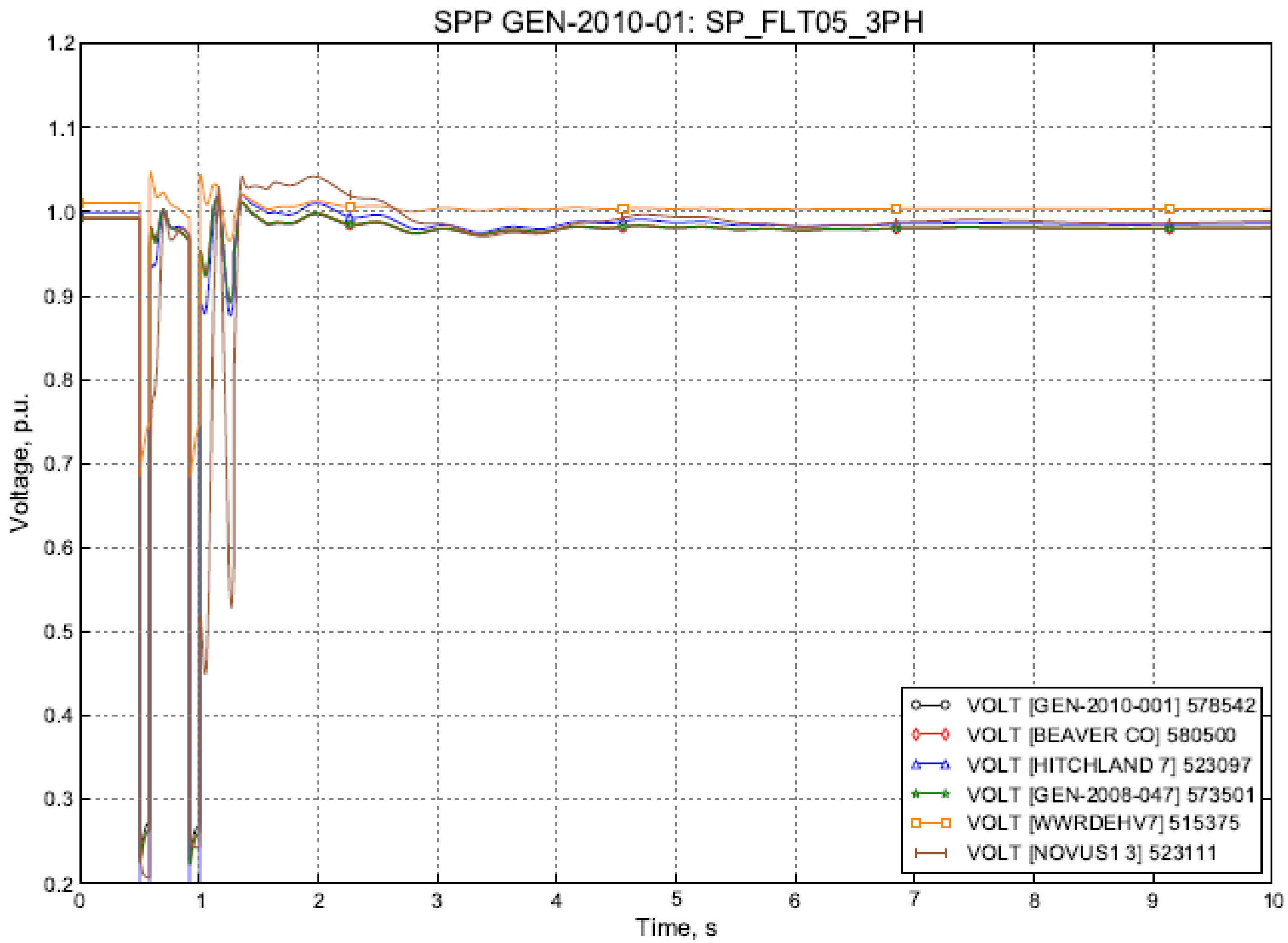

Figure 3-2. Response of select bus voltages during Contingency #5 (FLT05-3PH) for summer peak conditions.

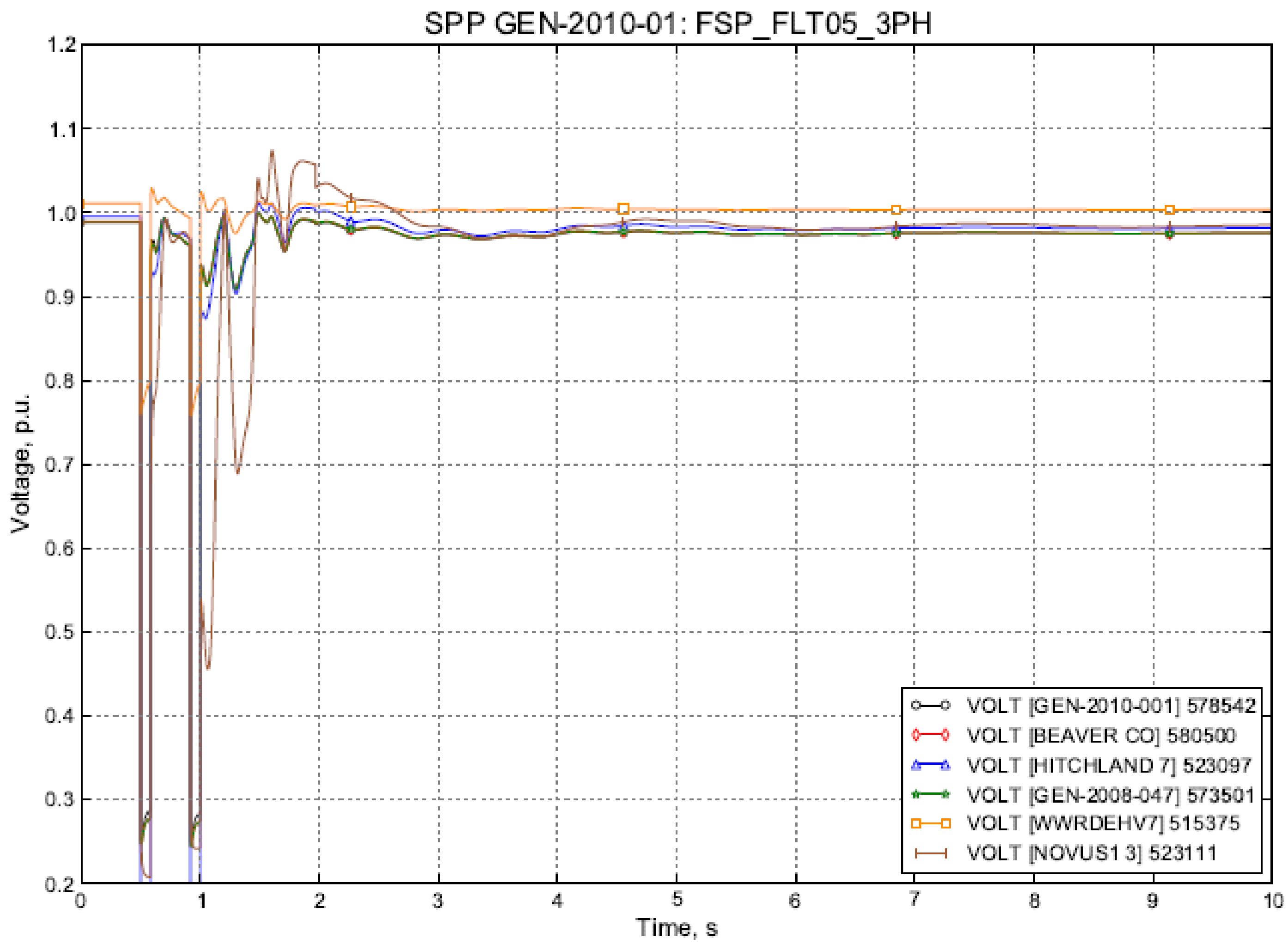

Figure 3-3. Response of select bus voltages during Contingency #5 (FLT05-3PH) for future summer peak conditions.

SECTION 4: POWER FACTOR ANALYSIS

The objective of this task is to quantify the power factor at the point of interconnection for the wind farms during base case and system contingencies. SPP transmission planning practice requires interconnecting generation projects to maintain the power factor (pf) at the Point of Interconnection (POI) near unity for system intact conditions and within +/- 0.95 pf for post-contingency conditions. This is analyzed by having the wind farm maintain a prescribed voltage schedule at the point of interconnection of 1.0 p.u. voltage, or if the pre-project voltage is higher than 1.0 p.u., to maintain the pre-project voltage schedule.

The three winter peak and summer peak power flows provided by SPP were examined prior to the Power Factor Analysis to ensure they contained the proposed study project modeled at 100% of the nameplate rating and any previously queued projects listed in Table 2-2. There was no suspect power flow data in the study area. The proposed study project was turned off during the power factor analysis. The wind farm was then replaced by a generator modeled at the high side bus with the same real power (MW) capability as the wind farm and open limits for the reactive power set point (Mvar). The generator was set to hold the POI scheduled bus voltage. Contingencies from the three-phase fault definitions provided in Table 2-3 were then applied and the reactive power required to maintain the bus voltage was recorded.

Approach

The study project (GEN-2010-001) was disabled and a generator was placed at the study project's point of interconnect bus. The generator was modeled with PGEN = 299.7 MW, QMin = -9999 Mvar, and QMax = 9999 Mvar. All buses and transformers connected from the study project's POI bus to the GEN-2010-001 generator were disabled. The pre-project voltage at the POI (Beaver County 345 kV - Bus 580500) for summer and winter peak conditions was 1.0 p.u. Therefore, the scheduled voltage for the POI was set to 1.0 p.u. for the summer peak conditions and 1.0 p.u. for winter peak condition.

The reactive compensation required to off-set the charging of the collector system and lead line was calculated by modeling GEN-2010-001 off-line and calculating the size of reactors placed at the 34.5kV collector buses which would result in zero VAR flow at the 345kV POI. This reactive compensation was not included, that is it was modeled off-line, in the calculation of reactive requirements for the base case or contingency conditions studied.

Results

The power factor was calculated for 2014 winter peak, 2015 summer peak, and 2015 future summer peak conditions. Table 4-1 shows the power factor results for GEN-2010-001. Note that a positive Q (Mvar) output illustrates that the generator is absorbing reactive power from the system, implying a leading power factor; a negative Q (Mvar) illustrates that the generator is supplying reactive power to the system, implying a lagging power factor. The Power Factor Analysis shows that GEN-2010-001 as a power factor range of 0.860 lagging (supplying) to 0.928 leading (consuming).

The reactive compensation required to off-set the charging of the collector system and lead line was calculated by modeling GEN-2010-001 off-line and calculating the amount of inductive capacity required at the 34.5kV collector buses which would result in zero VAR flow at the 345kV POI. The results are shown in Figure 4-1. A total of 12.7 MVAR of inductive support would be needed to off-set the line charging of the 34.5kV collector system and the 345kV lead line. This reactive compensation was not included, modeled off-line, in the calculation of reactive requirements for the base case or contingency conditions studied.

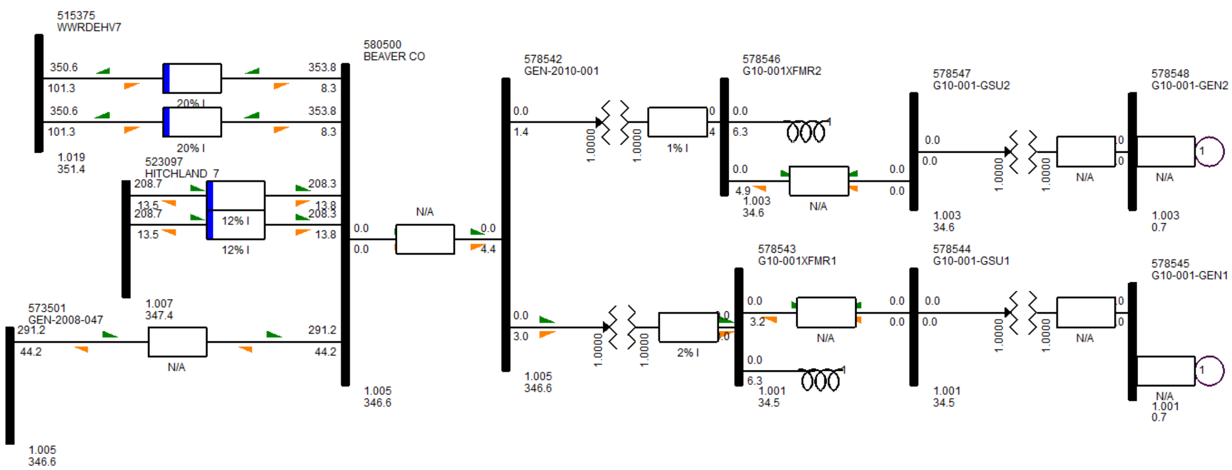

Figure 4-1. Power flow one-line diagram for illustrating the amount of reactive compensation required to off-set the charging of the collector system

Table 4-1
Power Factor Analysis: GEN-2010-001 (P_{GEN}=299.7 MW)*

Power Factor Analysis									
Power Factor Analysis: GEN-2010-001 (P_{GEN} = 299.7 MW)									
Case	Summer 2015 Peak			Winter 2014 Peak			Summer 2024 Peak		
	Power Factor		Q** (MVAR)	Power Factor		Q** (MVAR)	Power Factor		Q** (MVAR)
Base	0.9999	Leading	3.78	0.9986	Lagging	-16.00	0.9960	Lagging	-27.01
C1	0.9950	Lagging	-30.10	0.9821	Lagging	-57.44	0.9819	Lagging	-57.78
C3	0.9915	Lagging	-39.28	0.9837	Lagging	-54.77	0.9680	Lagging	-77.70
C5	0.9101	Lagging	-136.43	0.8659	Lagging	-173.12	0.8603	Lagging	-177.62
C7	0.9876	Lagging	-47.70	0.9779	Lagging	-64.11	0.9794	Lagging	-61.83
C9	0.9991	Lagging	-12.42	0.9937	Lagging	-33.83	0.9922	Lagging	-37.72
C11	0.9999	Lagging	-3.67	0.9990	Lagging	-13.17	0.9893	Lagging	-44.18
C13	0.9996	Leading	8.79	0.9997	Lagging	-7.56	N/A	N/A	N/A
C15	1.0000	Lagging	-0.47	0.9995	Lagging	-9.70	0.9905	Lagging	-41.71
C17	0.9267	Lagging	-121.50	0.9274	Lagging	-120.85	0.8788	Lagging	-162.75
C19	0.9999	Leading	3.78	0.9997	Lagging	-7.43	0.9986	Lagging	-16.08
C21	0.9999	Lagging	-5.15	0.9965	Lagging	-25.02	0.9945	Lagging	-31.57
C23	1.0000	Lagging	-0.96	0.9953	Lagging	-29.27	0.9931	Lagging	-35.38
C25	0.9994	Lagging	-10.39	0.9977	Lagging	-20.18	0.9940	Lagging	-32.98
C27	1.0000	Leading	1.41	0.9981	Lagging	-18.42	0.9957	Lagging	-27.83
C29	0.9999	Leading	3.74	0.9985	Lagging	-16.41	0.9958	Lagging	-27.55
C31	0.9999	Leading	3.78	0.9997	Lagging	-7.43	0.9986	Lagging	-16.08
C33	0.9999	Leading	3.78	0.9997	Lagging	-7.43	0.9986	Lagging	-16.08
C35	0.9999	Lagging	-3.12	0.9975	Lagging	-21.19	0.9932	Lagging	-35.01
C37	1.0000	Lagging	-1.99	0.9973	Lagging	-21.87	0.9943	Lagging	-32.01
C39	0.9999	Leading	3.82	0.9982	Lagging	-17.97	0.9965	Lagging	-25.01
C41	0.9999	Leading	3.78	0.9986	Lagging	-16.00	0.9960	Lagging	-27.01
C42	1.0000	Leading	0.00	0.9979	Lagging	-19.68	0.9959	Lagging	-27.18
C43	0.9969	Lagging	-23.56	0.9908	Lagging	-40.91	0.9933	Lagging	-34.93
C44	1.0000	Leading	0.98	0.9980	Lagging	-18.82	0.9964	Lagging	-25.43
C45	0.9984	Leading	17.05	0.9987	Lagging	-15.45	0.9956	Lagging	-28.24
C46	0.9998	Lagging	-6.05	0.9997	Leading	6.94	0.9997	Lagging	-7.76
C47	0.9284	Leading	119.93	0.9301	Leading	118.40	0.8854	Leading	157.37
C48	0.9968	Lagging	-23.98	0.9989	Lagging	-14.10	N/A	N/A	N/A

*The scheduled voltage for the POI (Beaver Co 345 kV) was 1.00 p.u. for summer peak and winter peak conditions.
**A positive Q (Mvar) output illustrates the generator is absorbing Mvars from the system, which implies a leading power factor; negative Q (Mvar) output shows the generator is supplying Mvars to the system implying a lagging power factor.

SECTION 5: CONCLUSIONS

Stability Analysis

For the 2014 Winter Peak case, the Stability Analysis determined that there was no wind turbine tripping that occurs from interconnecting GEN-2010-001 at 100% output. There were no low voltage recovery or stability issues observed for the winter peak conditions.

For the 2015 Summer Peak case, the Stability Analysis determined that there was no wind turbine tripping that occurs from interconnecting GEN-2010-001 at 100% output. There were no low voltage recovery or stability issues observed for the summer peak conditions.

For the 2024 Future Summer Peak case, the Stability Analysis determined that there was no wind turbine tripping that occurs from interconnecting GEN-2010-001 at 100% output. There were no low voltage recovery or stability issues observed for the future summer peak conditions.

Power Factor Analysis

The Power Factor Analysis shows that GEN-2010-001 as a power factor range of 0.860 lagging (supplying) to 0.928 leading (consuming). Additionally, 12.7 Mvars of reactance are found to be required during low wind conditions.