K: Stability Study for Group 3

SPP DISIS-2009-001 Group 3 Definitive Impact Study

Draft Report for

Southwest Power Pool

Prepared by:

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0. Certification

I hereby certify that this plan, specification, or report was prepared by me or under my direct supervision and that I am a duly Licensed Professional Engineer under the Laws of the State of **Arkansas**.

William Quaintance
Arkansas Registration Number 13865

1. Background and Scope

The DISIS-2009-001 Group 3 Definitive Impact Study is a generation interconnection study performed by Excel Engineering, Inc. for its non-affiliated client, Southwest Power Pool (SPP). Its purpose is to study the impacts of interconnecting the projects shown in Table 1-1. The in-service date assumed for the generation addition was 2010.

Table 1-1. Interconnection Requests Evaluated

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2007-040	200	Siemens 2.3MW	Holcomb (531449) – Spearville (531469) 345kV. Bus # 531000
GEN-2008-079	100.5	G.E. 1.5 MW	Tap Cudahy (539659) – Judson Large (539671) 115kV. Bus # 573029
GEN-2008-124	200	Siemens 2.3MW	Spearville (531469) 345kV

The previously-queued requests shown in Table 1-2 were included in this study.

Table 1-2. Nearby Interconnection Requests Already in the Queue

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2001-039A	105	Clipper 2.5MW	Judson Large – Greensburg 115kV (103)
GEN-2002-025A	150	GE 1.5 MW	Spearville 230kV (539695)
GEN-2004-014	154.5	GE 1.5 MW	Spearville 230kV (539695)
GEN-2005-012	250	Vestas V90 3.0MW	Spearville 345kV (531469)
GEN-2006-006	205	GE 1.5 MW	Spearville 230kV (539695)
GEN-2006-021	100	Clipper 2.5MW	Tap Harper (539668) – Medicine Lodge (539674) 138kV. Bus # 539638
GEN-2006-022	150	Clipper 2.5MW	Pratt 115kV (539687)
GEN-2007-038	200	Clipper 2.5MW	Spearville 345kV (531469)
GEN-2008-018	405	GE 1.5 MW	Finney 345kV (523853)

The study included a stability analysis for each proposed interconnection request. Contingencies that resulted in a prior-queued project tripping off-line, if any, were re-run with the prior-queued project's voltage and frequency tripping disabled. Since all of the three interconnection requests in this group are wind projects, a power factor analysis was performed.

ATC (Available Transfer Capability) studies were not performed as part of this study. These studies will be required at the time transmission service is actually requested. Additional transmission upgrades may be required based on that analysis.

Study assumptions in general have been based on Excel's knowledge of the electric power system and on the specific information and data provided by SPP. The accuracy of the conclusions contained within this study is sensitive to the assumptions made with respect to other generation additions and transmission improvements being contemplated by other entities. Changes in the assumptions of the timing of other generation additions or transmission improvements will affect this study's conclusions.

2. Executive Summary

The DISIS-2009-001 Group 3 Definitive Impact Study evaluated the impacts of interconnecting projects GEN-2007-040, GEN-2008-079, and GEN-2008-124 to the SPP electric system.

No stability problems were found during summer or winter peak conditions due to the addition of these generators.

Power factor requirements were determined, and all study plants must install sufficient reactive power resources to meet these requirements listed in Table 4-2. The reactive power resources need not be dynamically controlled. However, any change in wind turbine model or controls could change the stability results, possibly resulting in a need for a dynamically controlled reactive power supply.

With the assumptions described in this report, DISIS-2009-001 Group 3 should be able to connect without causing any stability problems on the SPP transmission grid.

3. Study Development and Assumptions

3.1 Simulation Tools

The Siemens Power Technologies, Inc. PSS/E power system simulation program Version 30.3.3 was used in this study.

3.2 Models Used

SPP provided its latest stability database cases for both summer and winter peak seasons. Each plant's PSS/E model had been developed prior to this study and was included in the power flow case and the dynamics database. As a result, no additional generator modeling was required. Power flow and dynamic model data for the study plants are provided in Appendix D.

Power flow one-line diagrams of the study projects in summer peak conditions are shown in Figure 3-1, Figure 3-2, and Figure 3-3. As the figures show, each plant model includes explicit representation of the radial transmission line, if any; the substation transformer(s) from transmission voltage to 34.5 kV; and the substation reactive power device(s), if any. The remainder of each wind farm is represented by one or more lumped equivalents including a generator, a step-up transformer, and a collector system impedance.

No special modeling is required of line relays in these cases, except for the special modeling related to the wind-turbine tripping.

3.3 Monitored Facilities

All generators in Areas 520 524 525 526 531 534 536 539, and 541 were monitored.

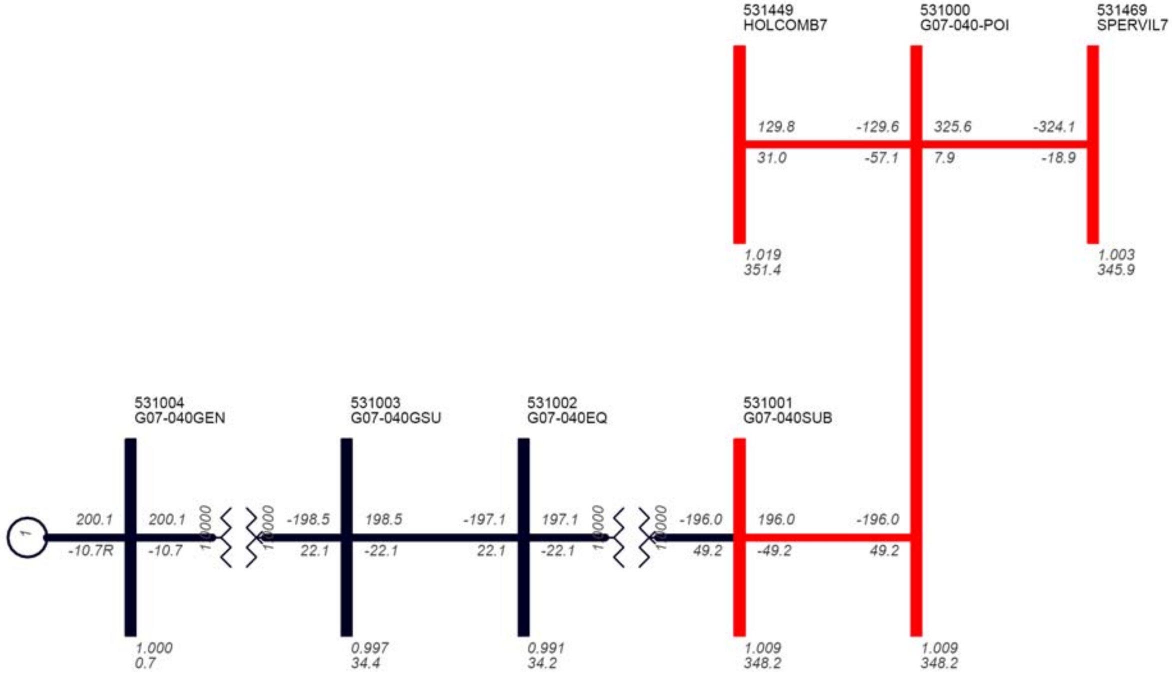

Figure 3-1. Power Flow One-line for GEN-2007-040 and adjacent equipment (SP)

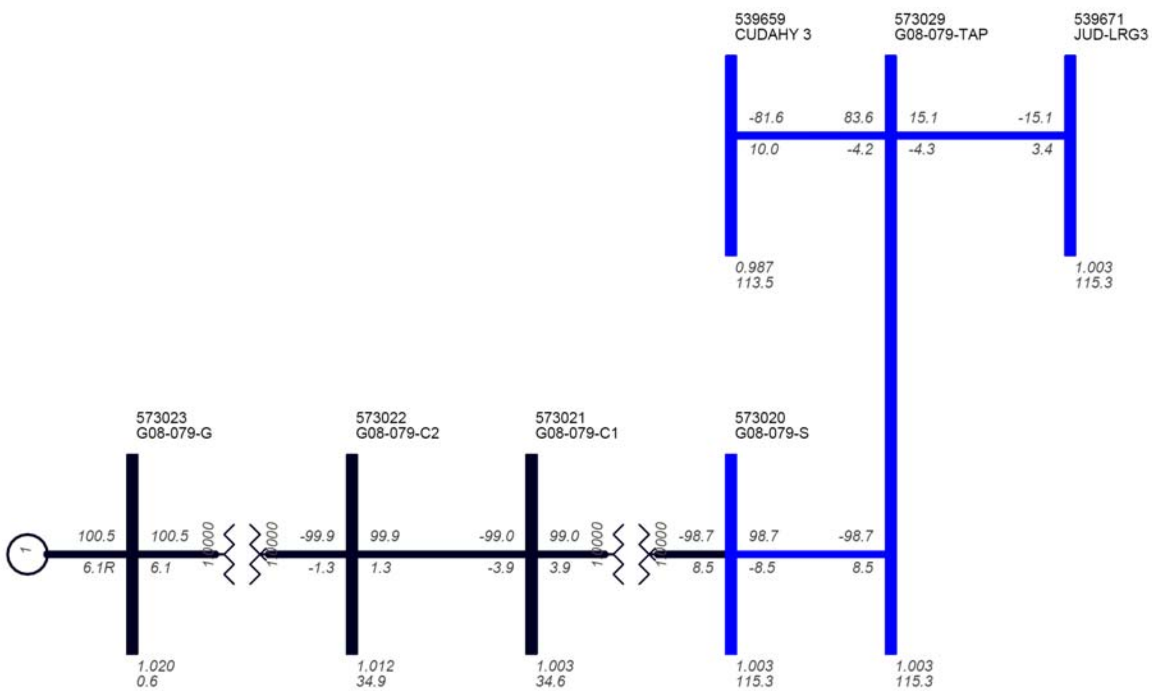

Figure 3-2. Power Flow One-line for GEN-2008-079 and adjacent equipment (SP)

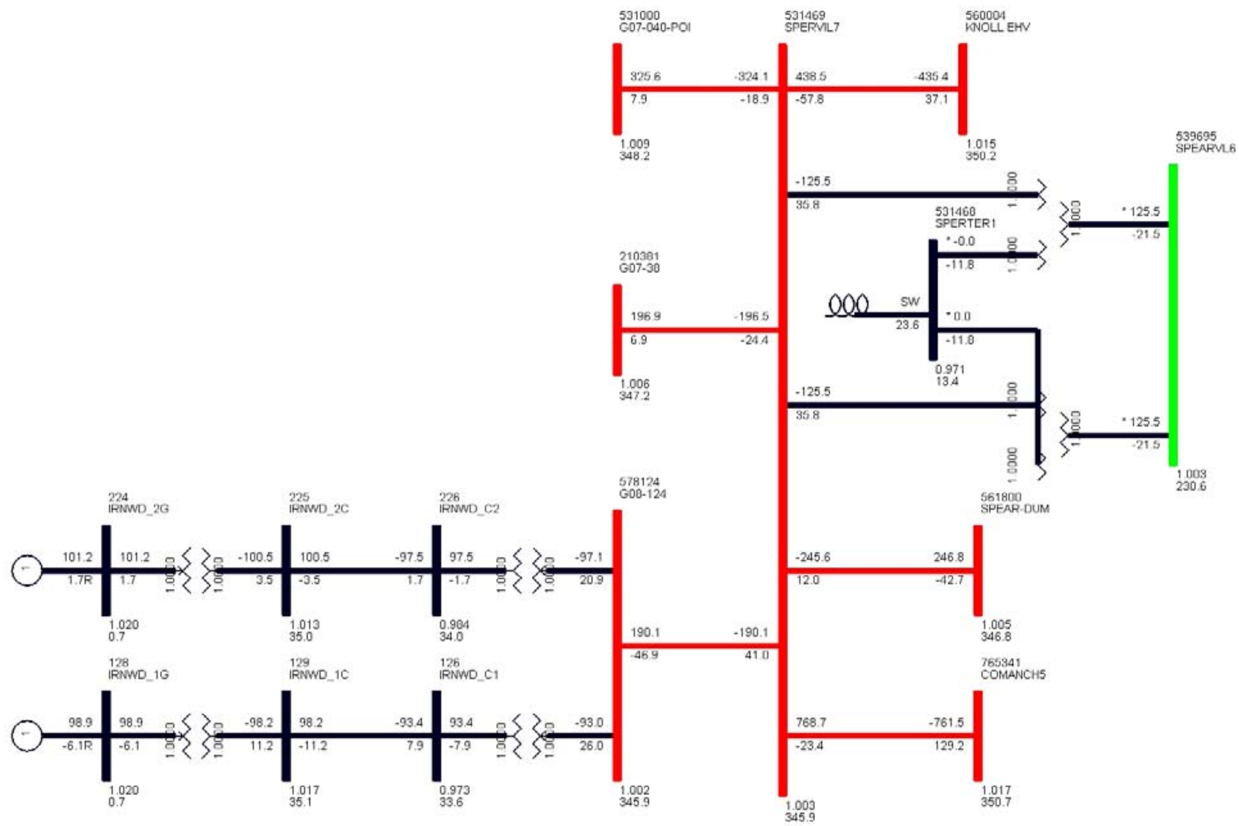

Figure 3-3. Power Flow One-line for GEN-2008-124 and adjacent equipment (SP)

3.4 Performance Criteria

The wind generators must comply with the FERC Order 661A on low voltage ride through for wind farms. Therefore, the wind generators should not trip off line for faults for under voltage relay actuation. If a wind generator trips off line, an appropriately sized SVC or STATCOM device may need to be specified to keep the wind generator on-line for the fault. SPP was consulted to determine if the addition of an SVC or STATCOM is warranted for the specific condition.

Contingencies that resulted in a prior-queued project tripping off-line, if any, were re-run with the prior-queued project's voltage and frequency tripping disabled to check for stability issues.

3.5 Performance Evaluation Methods

Since all of the interconnection requests are wind projects, a power factor analysis was performed. The power factor analysis consisted of modeling a var generator in each wind farm holding a voltage schedule at the POI. The voltage schedule was set equal to the higher of the voltage with the wind farm off-line or 1.0 per unit.

If the required power factor at the POI is beyond the capability of the studied wind turbines, then capacitor banks would be considered. Factors used in sizing capacitor banks would include two requirements of FERC Order 661A: the ability of the wind farm to ride through low voltage with and without capacitor banks and the ability of the wind farm to recover to pre-fault voltage. If a wind generator trips on high voltage, a leading power factor may be required.

ATC studies were not performed as part of this study. These studies will be required at the time transmission service is actually requested. Additional transmission facilities may be required based on subsequent ATC analysis.

Stability analysis was performed for each proposed interconnection request. Faults were simulated on transmission lines at the POIs and on other nearby transmission equipment. The faults in Table 3-1 were run for each case (three phase and single phase as noted).

Table 3-1. Fault Definitions for DISIS-2009-001 Group 3

Cont. No.	Cont. Name	Description
1	FLT01-3PH	3 phase fault on the Finney (523853) to GEN-2003-013 (560029) 345kV line, 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.
2	FLT02-1PH	*Single phase fault and sequence like previous*
3	FLT03-3PH	3 phase fault on one of the Finney (523853) to Holcomb (531449) 345kV lines, 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.
4	FLT41PH	*Single phase fault and sequence like previous*
5	FLT5-3PH	3 phase fault on the Holcomb (531449) to Setab (531465) 345kV line, near Holcomb. a. Apply fault at the Holcomb 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	FLT6-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
7	FLT7-3PH	3 phase fault on the Holcomb (531449) to GEN-2007-040 (531000) 345kV line, near GEN-2007-040. a. Apply fault at the GEN-2007-040 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	FLT8-1PH	*Single phase fault and sequence like previous*
9	FLT9-3PH	3 phase fault on the Holcomb 345kV (531449) to 115kV (531448) transformer, near the 345 kV bus. a. Apply fault at the Holcomb 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
10	FLT10-1PH	*Single phase fault and sequence like previous*
11	FLT11-3PH	3 phase fault on the Spearville (531469) to GEN-2007-040 (531000) 345kV line, near GEN-2007-040. a. Apply fault at the GEN-2007-040 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	3 phase fault on the Spearville (531469) to Comanche (765341) 345kV line, near Spearville. a. Apply fault at the Spearville 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 Spearville 345kV (531469) to 230kV (539695) transformer, near the 345 kV bus. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
16	FLT16-1PH	*Single phase fault and sequence like previous*
17	FLT17-3PH	3 phase fault on the Spearville 230kV (539695) to 345kV (531469) transformer, near the 230 kV bus. a. Apply fault at the Spearville 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
18	FLT18-1PH	*Single phase fault and sequence like previous*
19	FLT19-3PH	3 phase fault on the Spearville 230kV (539695) to 115kV (539694) transformer #2, near the 230 kV bus. a. Apply fault at the Spearville 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
20	FLT20-1PH	*Single phase fault and sequence like previous*
21	FLT21-3PH	3 phase fault on the Spearville (539695) to Mullergren (539679) 230kV line, near Spearville. a. Apply fault at the Spearville 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*

Cont. No.	Cont. Name	Description
23	FLT23-3PH	3 phase fault on the Mullergren (539679) to South Hays (530582) 230kV line, near Mullergren. a. Apply fault at the Mullergren 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 Mullergren (539679) to Circle (532871) 230kV line, near Mullergren. a. Apply fault at the Mullergren 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 Comanche (765341) to Medicine Lodge (765342) 345kV line, near Comanche. a. Apply fault at the Comanche 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.
28	FLT28-1PH	*Single phase fault and sequence like previous*
29	FLT29-3PH	3 phase fault on the Comanche (765341) to Woodward (515375) 345kV line, near Comanche. a. Apply fault at the Comanche 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.
30	FLT30-1PH	*Single phase fault and sequence like previous*
31	FLT31-3PH	3 phase fault on the GEN-2003-013 (560029) to Hitchland (523097) 345kV line, near GEN-2003-013. a. Apply fault at the GEN-2003-013 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.
32	FLT32-1PH	*Single phase fault and sequence like previous*
33	FLT33-3PH	3 phase fault on the Hitchland (523097) to Woodward (515375) 345kV line, 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.
34	FLT34-1PH	*Single phase fault and sequence like previous*
35	FLT35-3PH	3 phase fault on the Knoll (530558) to Smoky Hills (530592) 230kV line, near Knoll. a. Apply fault at the Knoll 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.
36	FLT36-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
37	FLT37-3PH	3 phase fault on the Spearville (531469) to Knoll (560004) 345kV line, near Spearville. a. Apply fault at the Spearville 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.
38	FLT38-1PH	*Single phase fault and sequence like previous*
39	FLT39-3PH	3 phase fault on the Knoll (560004) to Axtell (640065) 345kV line, near Knoll. a. Apply fault at the Knoll 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.
40	FLT40-1PH	*Single phase fault and sequence like previous*
41	FLT41-3PH	3 phase fault on the Knoll 345kV (560004) to 230kV (530558) transformer, near the 345 kV bus. a. Apply fault at the Knoll 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
42	FLT42-1PH	*Single phase fault and sequence like previous*
43	FLT43-3PH	3 phase fault on the GEN-2008-079 (573029) to Cudahy (539659) 115kV line, near GEN-2008-079. a. Apply fault at the GEN-2008-079 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.
44	FLT44-1PH	*Single phase fault and sequence like previous*
45	FLT45-3PH	3 phase fault on the GEN-2008-079 (573029) to Judson Large (539671) 115kV line, near GEN-2008-079. a. Apply fault at the GEN-2008-079 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.
46	FLT46-1PH	*Single phase fault and sequence like previous*
47	FLT47-3PH	3 phase fault on the GEN-2001-039A (103) to Judson Large (539671) 115kV line, near GEN-2001-039A. a. Apply fault at the GEN-2001-039A 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.
48	FLT48-1PH	*Single phase fault and sequence like previous*
49	FLT49-3PH	3 phase fault on the Cimarron Plant (539654) to Walkmeyer (531405) 115kV line, near Cimarron Plant. a. Apply fault at the Cimarron Plant 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.
50	FLT50-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
51	FLT51-3PH	3 phase fault on the Cimarron Plant (539654) to Hayne (539640) 115kV line, near Cimarron Plant. a. Apply fault at the Cimarron Plant 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.
52	FLT52-1PH	*Single phase fault and sequence like previous*
53	FLT53-3PH	3 phase fault on the Cimarron Plant (539654) to Seward (531467) 115kV line, near Cimarron Plant. a. Apply fault at the Cimarron Plant 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.
54	FLT54-1PH	*Single phase fault and sequence like previous*
55	FLT55-3PH	3 phase fault on the Spearville (539694) to North Judson Large (539771) 115kV line, near Spearville. a. Apply fault at the Spearville 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.
56	FLT56-1PH	*Single phase fault and sequence like previous*

4. Results and Observations

4.1 Stability Analysis Results

All faults were run for both summer and winter peak conditions. If a previously-queued generator tripped for any of these faults, the voltage and frequency tripping was disabled, and the fault was re-run to check for system stability. No tripping occurred in this study.

Table 4-1 summarizes the overall results for all faults run. Figure 4-1 through Figure 4-7 show representative summer peak season plots for faults at the POIs for each of the study projects. Complete sets of plots for both summer and winter peak seasons for each fault and each wind project are included in Appendices A and B.

The Power Factor analysis in Section 4.3 shows that GEN-2008-124 will be required to install reactive power compensation devices to achieve 0.95 power factor lagging at the POI.

The system remains stable for all simulated faults. All study projects stay on-line for all simulated faults.

Table 4-1. Summary of Stability Results

Cont. No.	Cont. Name	Description	Summer Peak Results	Winter Peak Results
1	FLT01-3PH	3 phase fault on the Finney (523853) to GEN-2003-013 (560029) 345kV line, near Finney.	OK	OK
2	FLT02-1PH	*Single phase fault and sequence like previous*	OK	OK
3	FLT03-3PH	3 phase fault on one of the Finney (523853) to Holcomb (531449) 345kV lines, near Finney.	OK	OK
4	FLT04-1PH	*Single phase fault and sequence like previous*	OK	OK
5	FLT05-3PH	3 phase fault on the Holcomb (531449) to Setab (531465) 345kV line, near Holcomb.	OK	OK
6	FLT06-1PH	*Single phase fault and sequence like previous*	OK	OK
7	FLT07-3PH	3 phase fault on the Holcomb (531449) to GEN-2007-040 (531000) 345kV line, near GEN-2007-040.	OK	OK
8	FLT08-1PH	*Single phase fault and sequence like previous*	OK	OK
9	FLT09-3PH	3 phase fault on the Holcomb 345kV (531449) to 115kV (531448) transformer, near the 345 kV bus.	OK	OK
10	FLT10-1PH	*Single phase fault and sequence like previous*	OK	OK
11	FLT11-3PH	3 phase fault on the Spearville (531469) to GEN-2007-040 (531000) 345kV line, near GEN-2007-040.	OK	OK
12	FLT12-1PH	*Single phase fault and sequence like previous*	OK	OK
13	FLT13-3PH	3 phase fault on the Spearville (531469) to Comanche (765341) 345kV line, near Spearville.	OK	OK

Cont. No.	Cont. Name	Description	Summer Peak Results	Winter Peak Results
14	FLT14-1PH	*Single phase fault and sequence like previous*	OK	OK
15	FLT15-3PH	3 phase fault on the Spearville 345kV (531469) to 230kV (539695) transformer, near the 345 kV bus.	OK	OK
16	FLT16-1PH	*Single phase fault and sequence like previous*	OK	OK
17	FLT17-3PH	3 phase fault on the Spearville 230kV (539695) to 345kV (531469) transformer, near the 230 kV bus.	OK	OK
18	FLT18-1PH	*Single phase fault and sequence like previous*	OK	OK
19	FLT19-3PH	3 phase fault on the Spearville 230kV (539695) to 115kV (539694) transformer #2, near the 230 kV bus.	OK	OK
20	FLT20-1PH	*Single phase fault and sequence like previous*	OK	OK
21	FLT21-3PH	3 phase fault on the Spearville (539695) to Mullergren (539679) 230kV line, near Spearville.	OK	OK
22	FLT22-1PH	*Single phase fault and sequence like previous*	OK	OK
23	FLT23-3PH	3 phase fault on the Mullergren (539679) to South Hays (530582) 230kV line, near Mullergren.	OK	OK
24	FLT24-1PH	*Single phase fault and sequence like previous*	OK	OK
25	FLT25-3PH	3 phase fault on the Mullergren (539679) to Circle (532871) 230kV line, near Mullergren.	OK	OK
26	FLT26-1PH	*Single phase fault and sequence like previous*	OK	OK
27	FLT27-3PH	3 phase fault on the Comanche (765341) to Medicine Lodge (765342) 345kV line, near Comanche.	OK	OK
28	FLT28-1PH	*Single phase fault and sequence like previous*	OK	OK
29	FLT29-3PH	3 phase fault on the Comanche (765341) to Woodward (515375) 345kV line, near Comanche.	OK	OK
30	FLT30-1PH	*Single phase fault and sequence like previous*	OK	OK
31	FLT31-3PH	3 phase fault on the GEN-2003-013 (560029) to Hitchland (523097) 345kV line, near GEN-2003-013.	OK	OK
32	FLT32-1PH	*Single phase fault and sequence like previous*	OK	OK
33	FLT33-3PH	3 phase fault on the Hitchland (523097) to Woodward (515375) 345kV line, near Hitchland.	OK	OK
34	FLT34-1PH	*Single phase fault and sequence like previous*	OK	OK
35	FLT35-3PH	3 phase fault on the Knoll (530558) to Smoky Hills (530592) 230kV line, near Knoll.	OK	OK
36	FLT36-1PH	*Single phase fault and sequence like previous*	OK	OK
37	FLT37-3PH	3 phase fault on the Spearville (531469) to Knoll (560004) 345kV line, near Spearville.	OK	OK
38	FLT38-1PH	*Single phase fault and sequence like previous*	OK	OK
39	FLT39-3PH	3 phase fault on the Knoll (560004) to Axtell (640065) 345kV line, near Knoll.	OK	OK
40	FLT40-1PH	*Single phase fault and sequence like previous*	OK	OK

Cont. No.	**Cont. Name**	**Description**	**Summer Peak Results**	**Winter Peak Results**
41	FLT41-3PH	3 phase fault on the Knoll 345kV (560004) to 230kV (530558) transformer, near the 345 kV bus.	OK	OK
42	FLT42-1PH	*Single phase fault and sequence like previous*	OK	OK
43	FLT43-3PH	3 phase fault on the GEN-2008-079 (573029) to Cudahy (539659) 115kV line, near GEN-2008-079.	OK	OK
44	FLT44-1PH	*Single phase fault and sequence like previous*	OK	OK
45	FLT45-3PH	3 phase fault on the GEN-2008-079 (573029) to Judson Large (539671) 115kV line, near GEN-2008-079.	OK	OK
46	FLT46-1PH	*Single phase fault and sequence like previous*	OK	OK
47	FLT47-3PH	3 phase fault on the GEN-2001-039A (103) to Judson Large (539671) 115kV line, near GEN-2001-039A.	OK	OK
48	FLT48-1PH	*Single phase fault and sequence like previous*	OK	OK
49	FLT49-3PH	3 phase fault on the Cimarron Plant (539654) to Walkmeyer (531405) 115kV line, near Cimarron Plant.	OK	OK
50	FLT50-1PH	*Single phase fault and sequence like previous*	OK	OK
51	FLT51-3PH	3 phase fault on the Cimarron Plant (539654) to Hayne (539640) 115kV line, near Cimarron Plant.	OK	OK
52	FLT52-1PH	*Single phase fault and sequence like previous*	OK	OK
53	FLT53-3PH	3 phase fault on the Cimarron Plant (539654) to Seward (531467) 115kV line, near Cimarron Plant.	OK	OK
54	FLT54-1PH	*Single phase fault and sequence like previous*	OK	OK
55	FLT55-3PH	3 phase fault on the Spearville (539694) to North Judson Large (539771) 115kV line, near Spearville.	OK	OK
56	FLT56-1PH	*Single phase fault and sequence like previous*	OK	OK

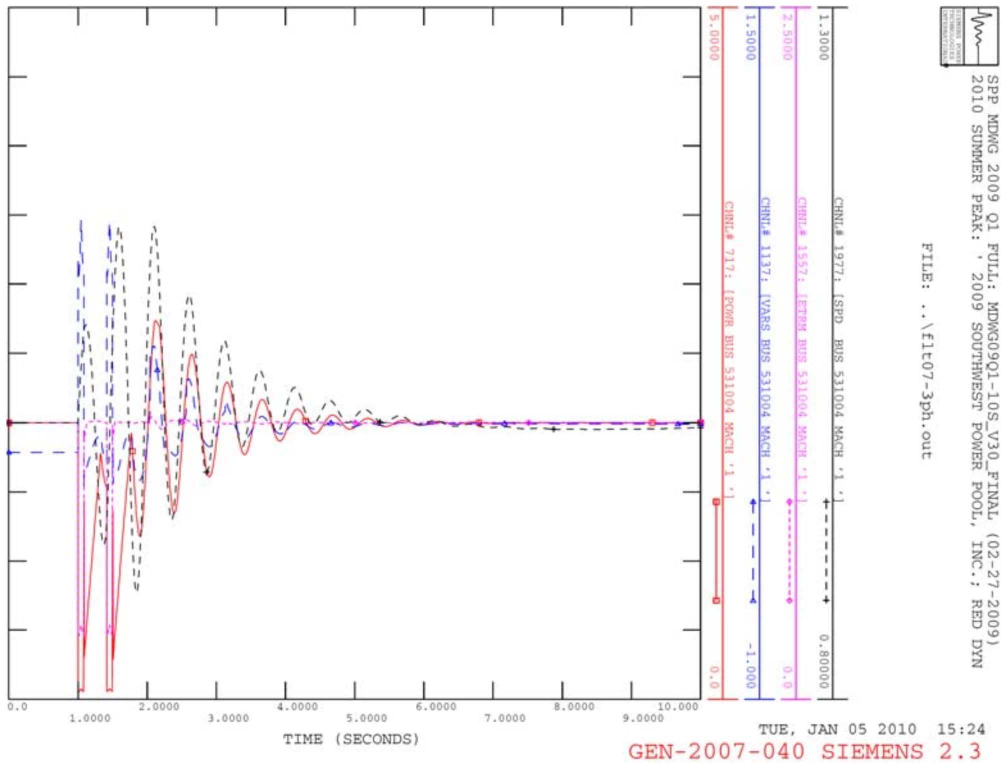

Figure 4-1. **GEN-2007-040 Plot for Fault 7 – 3-Phase Fault on the Holcomb to GEN-2007-040 345 kV line, near GEN-2007-040**

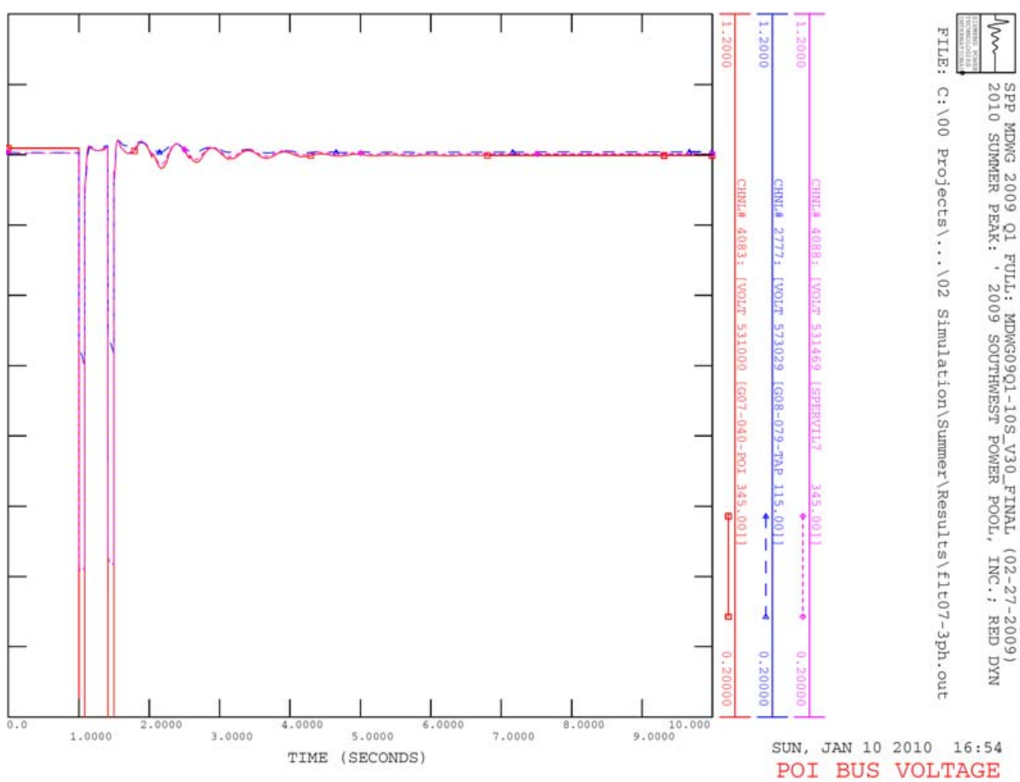

Figure 4-2. **POI Voltages Plot for Fault 7 – 3-Phase Fault on the Holcomb to GEN-2007-040 345 kV line, near GEN-2007-040**

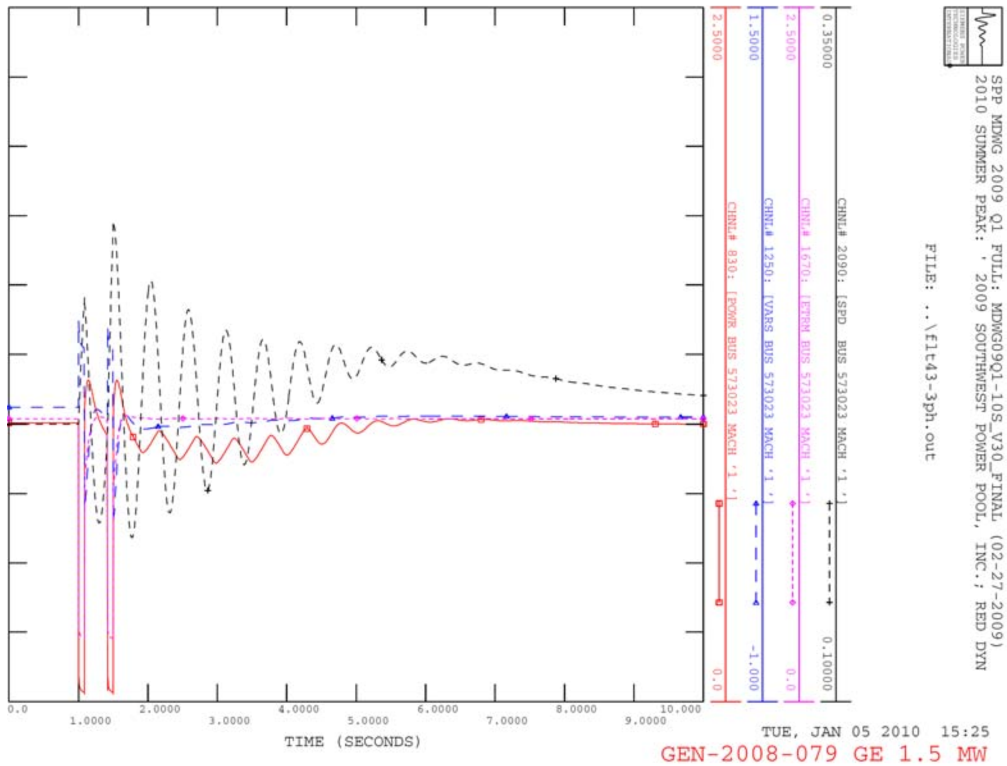

Figure 4-3. **GEN-2008-079 Plot for Fault 43 – 3-Phase Fault on the GEN-2008-079 to Cudahy 115 kV line, near GEN-2008-079**

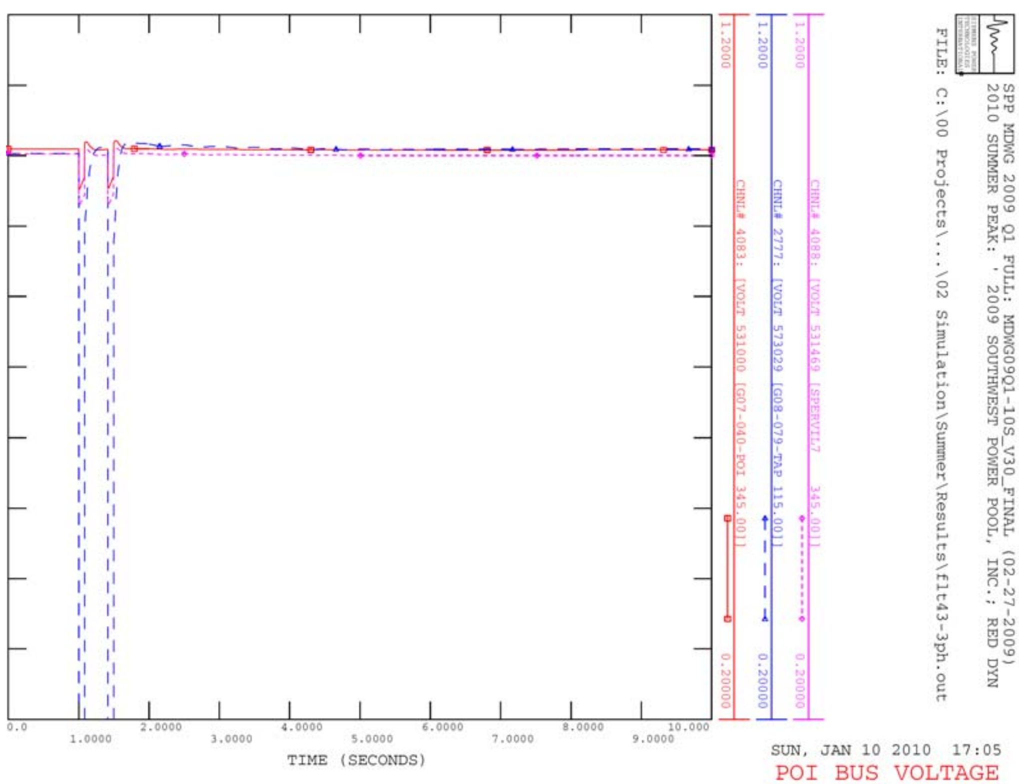

Figure 4-4. **POI Voltages Plot for Fault 43 – 3-Phase Fault on the GEN-2008-079 to Cudahy 115 kV line, near GEN-2008-079**

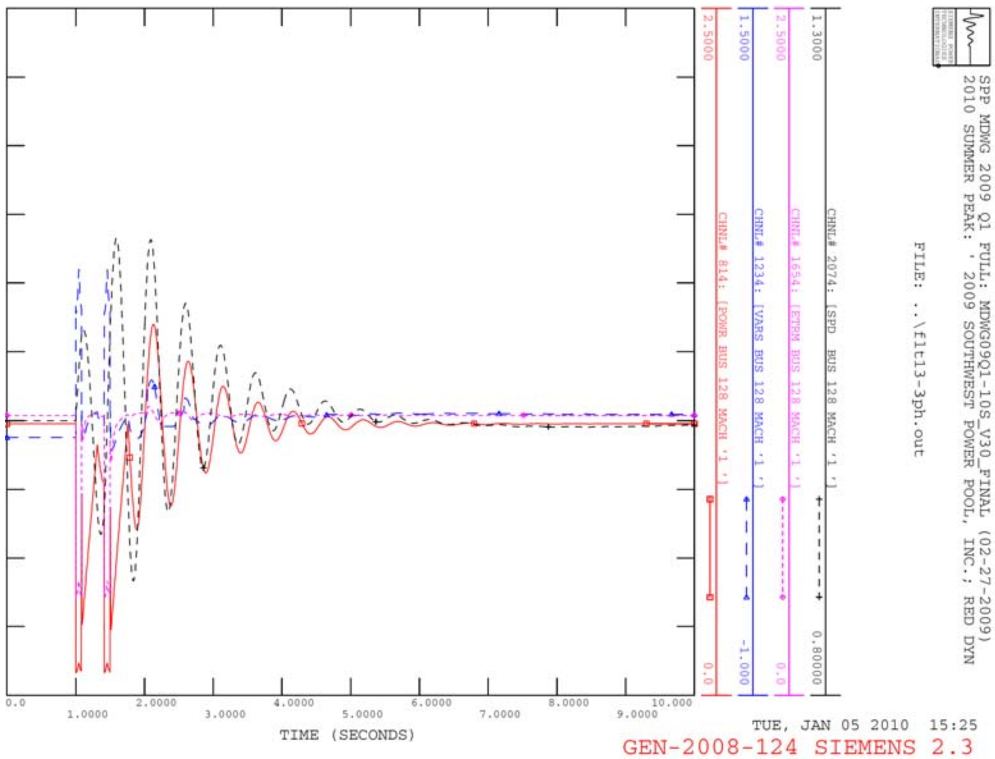

Figure 4-5. GEN-2008-124 (Unit 1) Plot for Fault 13 – 3-Phase Fault on the Spearville to Comanche 345 kV line, near Spearville

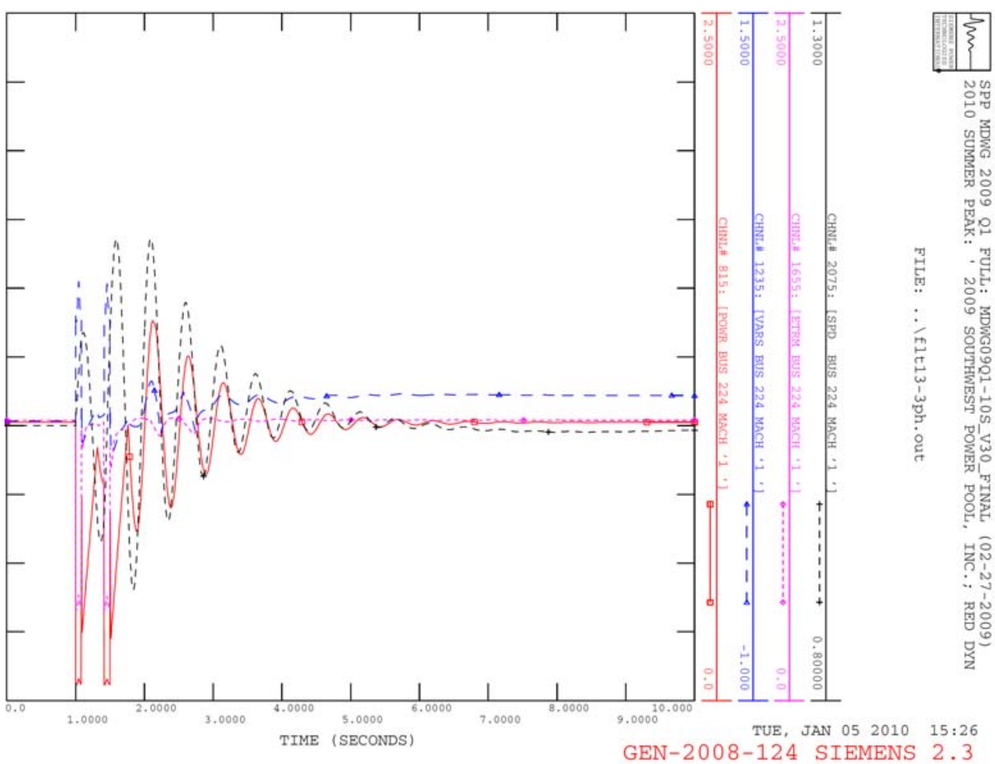

Figure 4-6. GEN-2008-124 (Unit 2) Plot for Fault 13 – 3-Phase Fault on the Spearville to Comanche 345 kV line, near Spearville

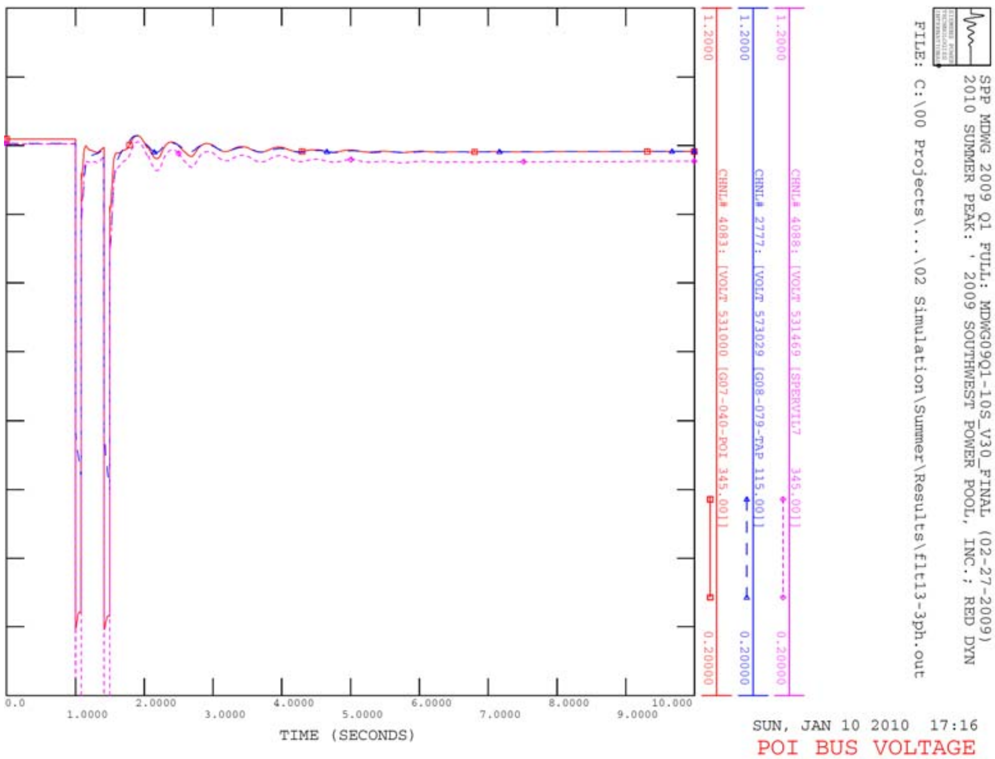

Figure 4-7. POI Voltages Plot for Fault 13 – 3-Phase Fault on the Spearville to Comanche 345 kV line, near Spearville

4.2 Generator Performance

All the study projects and prior-queued projects perform well for all faults, with no tripping evident.

4.3 Power Factor Requirements

All stability faults were tested as power flow contingencies to determine the power factor requirements for the wind farm study projects to maintain scheduled voltage at their respective points of interconnection (POI). The voltage schedules are set equal to the voltages at the POIs before the projects are added, with a minimum of 1.0 per unit. Fictitious reactive power sources were added to the study projects to maintain scheduled voltage during all studied contingencies. The MW and Mvar injections from the study projects at the POIs were recorded and the resulting power factors were calculated for all contingencies for summer peak and winter peak cases. The most leading and most lagging power factors determine the minimum power factor range capability that the study projects must install before commercial operation.

If more than one study project shared a single POI (none in this case), the projects were grouped together and a common power factor requirement was determined for those study projects. This ensures that none of the study projects is required to provide more or less than its fair share of the reactive power requirements at a single POI. *Prior-queued* projects at the same POI, if any, were not grouped with the study projects because their interconnection requirements were determined in previous studies.

Per FERC and SPP Tariff requirements, if the power factor needed to maintain scheduled voltage were less than 0.95 lagging, then the requirement would be set to 0.95 lagging. This limit was reached for GEN-2008-124. Much greater reactive power supply would be needed to meet the voltage schedules under some contingencies, but only 0.95 lagging will be required. The limit for leading power factor requirement is also 0.95, but this level was not reached for any project.

The proposed DISIS-2009-001 Group 3 projects cause heavy loading on the 345 kV line from Spearville to Comanche. This results in large reactive power consumption by this line and large reactive power injections needed by GEN-2008-124 to maintain voltage schedule, as low as 0.622 power factor during outage of the 345 kV line from Spearville to Knoll.

The final power factor requirements are shown in Table 4-2 below. These are only the minimum power factor ranges. A project developer may install more capability than this if desired.

The full details for each contingency in summer and winter peak cases are given in Appendix C.

Table 4-2. Power Factor Requirements [1]

Project	MW	Turbine	POI	Final PF Requirement	
				Lagging [2]	Leading [3]
GEN-2007-040	200	Siemens 2.3MW	Holcomb – Spearville 345kV line	0.976	0.956
GEN-2008-079	100.5	G.E. 1.5 MW	Tap Cudahy – Judson Large 115kV line	1.0	0.960
GEN-2008-124	200	Siemens 2.3MW	Spearville 345kV bus	0.950	1.0

Notes:
1. For each plant, the table shows the minimum required power factor capability at the point of interconnection that must be designed and installed with the wind farm. The power factor capability at the POI includes the net effect of the wind turbine generators, transformer and collector line impedances, and any reactive compensation devices installed on the plant side of the meter. Installing more capability than the minimum requirement is acceptable.
2. Lagging is when the generating plant is supplying reactive power to the transmission grid. In this situation, the alternating current sinusoid "lags" behind the alternating voltage sinusoid, meaning that the current peaks shortly after the voltage.
3. Leading is when the generating plant is taking reactive power from the transmission grid. In this situation, the alternating current sinusoid "leads" the alternating voltage sinusoid, meaning that the current peaks shortly before the voltage.

5. Conclusions

The DISIS-2009-001 Group 3 Definitive Impact Study evaluated the impacts of interconnecting the project shown below.

Table 5-1. Interconnection Requests Evaluated

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2007-040	200	Siemens 2.3MW	Holcomb (531449) – Spearville (531469) 345kV. Bus # 531000
GEN-2008-079	100.5	G.E. 1.5 MW	Tap Cudahy (539659) – Judson Large (539671) 115kV. Bus # 573029
GEN-2008-124	200	Siemens 2.3MW	Spearville (531469) 345kV

No stability problems were found during summer or winter peak conditions due to the addition of these generators.

Power factor requirements were determined, and all study plants must install sufficient reactive power resources to meet these requirements listed in Table 4-2. The reactive power resources need not be dynamically controlled. However, any change in wind turbine model or controls could change the stability results, possibly resulting in a need for a dynamically controlled reactive power supply.

With the assumptions described in this report, DISIS-2009-001 Group 3 should be able to connect without causing any stability problems on the SPP transmission grid.

Appendix A – Summer Peak Plots

See attachment.

Appendix B – Winter Peak Plots

See attachment.

Appendix C – Power Factor Details

See attachment.

Appendix D – Project Model Data

See attachment.

L: Stability Study for Group 4

Pterra Consulting

Technical Report R104-10

Impact Study for Generation Interconnection Request DISIS-2009-001 (Group 4)

Submitted to

Southwest Power Pool

January 2010

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Contents

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Executive Summary

This report presents the impact study comprising of power factor and stability simulation of the proposed interconnection of DISIS-2009-001 (Group 4) consisting of Gen-2008-025 (the "Project"). The Project has a nominal maximum rating of 101 MW using Siemens 2.3 MW wind turbine generators ("WTGs"). The Point of Interconnection ("POI") of the Project is Ruleton 115 kV substation.

The analysis was conducted through the Southwest Power Pool ("SPP") Tariff. Power factor analysis and transient stability simulations were conducted with the Project in service at full output of 101 MW.

Two base cases, 2010 summer and 2009 winter conditions, each comprising of a power flow and corresponding dynamics database, were provided by SPP.

The results of the Power Factor analysis showed that with the study Project must maintain a power factor range in which they are supplying or absorbing vars at the point of interconnection in accordance with the requirements in Section 2.

Forty-six (46) disturbances were considered for the transient stability simulations which included 3-phase faults, as well as, 1-phase to ground faults, at the locations defined by SPP. The Siemens WTGs were modeled with voltage and frequency ride through protection set to manufacturer default settings. The results of the simulations showed no angular or voltage instability problems for the 46 disturbances. The study finds that the interconnection of the proposed 101 MW Project does not impact stability performance of the SPP system for the contingencies tested on the supplied base cases.

Section 1. Introduction

1.1. Project Overview

This report presents the impact study comprising of power factor and stability simulation of the proposed interconnection of DISIS-2009-001 (Group 4) consisting of Gen-2008-025 (the "Project"). The Project has a nominal maximum rating of 101 MW using Siemens 2.3 MW wind turbine generators ("WTGs"). The Project's Point of Interconnection ("POI") is Ruleton 115 kV substation. Figure 1-1 shows a conceptual interconnection diagram of the Project to the 115 kV transmission network.

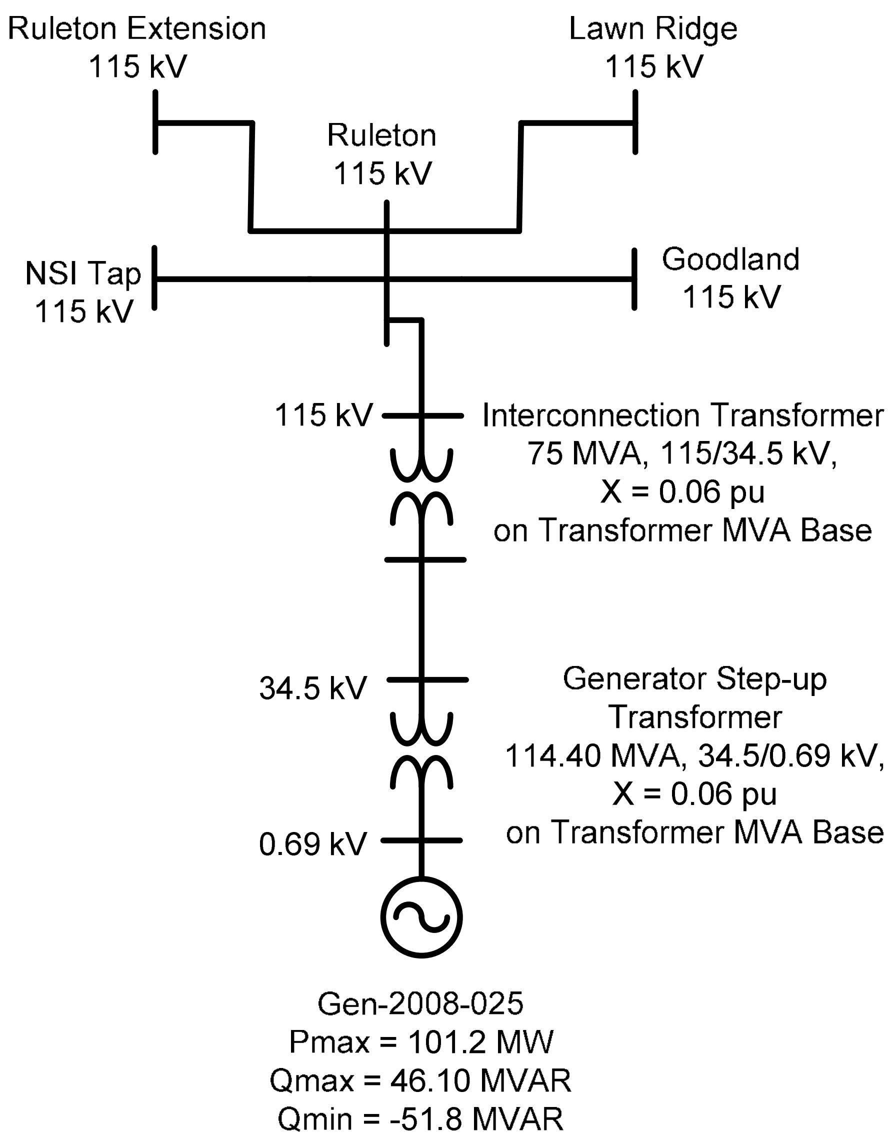

Figure 1-1 Interconnection Plan for the Project to SPP's 115 kV System

To simplify the model of the wind farm while capturing the effect of the different impedances of cables (due to change of the conductor size and length), the wind turbines connected to the same 34.5 kV feeder end points were aggregated into one equivalent unit. An equivalent impedance of that feeder was represented by taking the equivalent series impedances of the different feeders connecting the wind turbines. SPP modeled the proposed 101 MW wind farm in the provided power flow cases with one (1) equivalent unit as shown in Figure 1-1. Table 1-1 shows a list of the prior queued projects that are included in the base case.

Table 1-1 List of Prior Queued Projects

Request	Size	Wind Turbine Model	Point of Interconnection
GEN-2001-039M	99	Vestas V90 3.0MW	Leoti – City Services 115kV
GEN-2006-034	81	GE 1.5 MW	Kanardo – Sharon Springs 115kV
GEN-2006-040	108	Acciona 1.5 MW	Mingo 115kV
GEN-2007-011	135	Acciona 1.5 MW	Syracuse 115kV
GEN-2007-013	100	GE 1.5 MW	Selkirk 115kV
GEN-2008-017	300	GE 1.5 MW	Setab 345kV

1.2. Objectives

The objectives of the study are to conduct power factor analysis and to determine the impact on system stability of interconnecting a proposed 101 MW wind farm to SPP's transmission system.

Section 2. Power Factor Analysis

2.1. Methodology

Power factor analysis was conducted for the Project using a methodology which is summarized as follows:

1. Model a VAR generator at the Project's 115 kV bus. The VAR generator is set to hold a voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases for summer and winter or 1.0 pu voltage (whichever is higher).

2. Steady state contingency analysis is conducted to determine the power factor necessary at the POI for each contingency.

3. According to the contingency analysis results, determine whether capacitors are required for the Project or not.

4. If the required power factor at the POI is beyond the capability of the studied wind turbines to meet (at the POI) capacitor banks are considered. The preference is to locate the capacitance banks is on the 34.5 kV Customer side. Factors to sizing capacitor banks include:

   4.1. The ability of the wind farm to meet FERC Order 661A (low voltage ride through) with and without capacitor banks.

   4.2. The ability of the wind farm to meet FERC Order 661A (wind farm recovery to pre-fault voltage).

   4.3. If wind farms trips on high voltage, power factor lower than unity may be required.

2.2. Analysis

A VAR generator was modeled in the provided power flow cases for summer and winter at the POI. The VAR generator was set to hold a voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases for summer and winter. These values are 1.0056 pu and 1.006 pu, for summer and winter power flow cases respectively.

Contingency analysis was run for all the contingencies listed in the fault definition table (Table 3-4). A summary of the contingency analysis results, according to Table 2-1, for both summer and winter power flow cases are as follows:

- The loss of any branch in the contingency list showed that the VAR generator is either absorbing or delivering MVAR to the system to hold a voltage schedule at the POI consistent with the voltage schedule in the provided power flow cases for summer and winter.

- The results of the Power Factor analysis showed that with the study Project must maintain a power factor range in which they are supplying or absorbing vars at the point of interconnection in accordance with the requirements in Section 2.

Table 2-1 VAR Generator Output in Summer and Winter Peak Power Flow Cases

Season	Contingency Description	Power Factor		MW Injection of Project @ POI	MVAR @ POI
10SP	BASE CASE	0.9999	Lag	-99.5	-1.1
	531465 Setab 345 531449 Holcomb 345 1	0.9928	Lag	-99.5	-12.0
	531465 Setab 345 531451 Mingo 345 1	0.9991	Lag	-99.5	-4.3
	531465 Setab 345 531464 Setab 115 1	0.9937	Lag	-99.5	-8.0
	531451 Mingo 345 640325 Red Willow 345 1	0.9962	Lag	-99.5	-8.7
	531451 Mingo 345 Mingo 531429 115 1	0.9920	Lag	-99.5	-12.7
	640183 Gentleman 345 640252 Keystone 345 1	1.0000	Lag	-99.5	-0.2
	640183 Gentleman 345 640374 Sweetwater 345 1	0.9999	Lag	-99.5	-1.0
	531449 Holcomb 345 531000 GEN_2007_40 345 1	0.9897	Lag	-99.5	-14.4
	531449 Holcomb 345 531448 Holcomb 115 1	0.9958	Lag	-99.5	-9.2
	523853 Finney 345 560029 GEN-2003-013 345 1	0.9995	Lag	-99.5	-3.0
	531469 Spearville 345 560004 Knoll 345 1	0.9995	Lag	-99.5	-3.2
	531469 Spearville 345 765341 Comanche 345 1	1.0000	Lag	-99.5	-2.0
	531357 Ruleton 115 531356 NSI Tap 115 1	0.9924	Lead	-99.5	12.3
	531357 Ruleton 115 531368 Lawn Ridge 115 1	1.0000	Lead	-99.5	0.7
	531357 Ruleton 115 531443 Goodland 115 1	0.9985	Lag	-99.5	-5.5
	531438 Tribune Switch 115 531434 Selkirk 115 1	1.0000	Lag	-99.5	-0.5
	531439 Tribune Switch 115 531437 Syracuse 115 1	1.0000	Lead	-99.5	0.1
	531437 Syracuse 115 531440 Williamson 115 1	0.9864	Lag	-99.5	-16.6
	530554 Atwood 115 530555 Colby 115 1	0.9948	Lag	-99.5	-10.2
	531364 Atwood Switch 115 531367 Herndon 115 1	0.9975	Lead	-99.5	7.2
	531438 Tribune Switch 115 531431 Palmer 115 1	0.9956	Lag	-99.5	-9.4
	530555 Colby 115 530556 Hoxie 115 1	0.9994	Lag	-99.5	-3.5
	531429 Mingo 115 530559 Pheasant Run 115 1	1.0000	Lead	-99.5	0.6
09WP	BASE CASE	1.0000	Lag	-99.5	-0.8
	531465 Setab 345 531449 Holcomb 345 1	0.9897	Lag	-99.5	-14.4
	531465 Setab 345 531451 Mingo 345 1	0.9993	Lag	-99.5	-3.6
	531465 Setab 345 531464 Setab 115 1	0.9911	Lag	-99.5	-6.1
	531451 Mingo 345 640325 Red Willow 345 1	0.9974	Lag	-99.5	-7.2
	531451 Mingo 345 Mingo 531429 115 1	0.9975	Lag	-99.5	-7.0
	640183 Gentleman 345 640252 Keystone 345 1	1.0000	Lag	-99.5	0.0
	640183 Gentleman 345 640374 Sweetwater 345 1	0.9999	Lag	-99.5	-1.0
	531449 Holcomb 345 531000 GEN_2007_40 345 1	0.9924	Lag	-99.5	-12.3
	531449 Holcomb 345 531448 Holcomb 115 1	0.9948	Lag	-99.5	-10.2
	523853 Finney 345 560029 GEN-2003-013 345 1	0.9998	Lag	-99.5	-2.1
	531469 Spearville 345 560004 Knoll 345 1	0.9995	Lag	-99.5	-3.2
	531469 Spearville 345 765341 Comanche 345 1	0.9995	Lag	-99.5	-2.1
	531357 Ruleton 115 531356 NSI Tap 115 1	0.9943	Lead	-99.5	10.7
	531357 Ruleton 115 531368 Lawn Ridge 115 1	1.0000	Lag	-99.5	-0.9
	531357 Ruleton 115 531443 Goodland 115 1	0.9995	Lag	-99.5	-3.1
	531438 Tribune Switch 115 531434 Selkirk 115 1	1.0000	Lag	-99.5	-0.3
	531439 Tribune Switch 115 531437 Syracuse 115 1	1.0000	Lead	-99.5	1.7

Season	Contingency Description	Power Factor		MW Injection of Project @ POI	MVAR @ POI
	531437 Syracuse 115 531440 Williamson 115 1	0.9830	Lag	-99.5	-18.6
	530554 Atwood 115 530555 Colby 115 1	0.9964	Lag	-99.5	-8.5
	531364 Atwood Switch 115 531367 Herndon 115 1	0.9982	Lead	-99.5	7.5
	531438 Tribune Switch 115 531431 Palmer 115 1	0.9917	Lag	-99.5	-12.9
	530555 Colby 115 530556 Hoxie 115 1	0.9989	Lag	-99.5	-4.7
	531429 Mingo 115 530559 Pheasant Run 115 1	1.0000	Lead	-99.5	0.1

2.3. Conclusions

The results of the Power Factor analysis showed that with the study Project must maintain a power factor range in which they are supplying or absorbing vars at the point of interconnection in accordance with the requirements in Section 2.

3.1. Modeling of the Siemens 2.3 MW Wind Turbine Generators

For the stability simulations, the Siemens 2.3 MW wind turbine generators were modeled using the provided Siemens 2.3 MW wind turbine dynamic model set. Table 3-1 shows the data for Siemens 2.3 MW WTG.

Table 3-1 Siemens 2.3 MW Wind Turbine Generator Data

Parameter	Value
Base kV	0.69
WTG MBASE	2.30
Transformer MBASE	2.60
Transformer R on Transformer Base	0.0084
Transformer X on Transformer Base	0.0600
Transformer Tap	1.00
Pmax (MW)	2.30

The Siemens WTGs have ride-through capability for voltage and frequency. Detailed ride through relays' manufacturer settings are shown in Table 3-2 and Table 3-3.

Table 3-2 Over/Under Frequency Relay Settings for Siemens 2.3 MW

Frequency Settings in Per Unit	Time Setting (s)	Relay Activation Time (s)
0.95	10.0	0.0
0.94	0.10	0.0
1.04	0.10	0.0

Table 3-3 Over/Under Voltage Relay Settings for Siemens 2.3 MW

Voltage Settings in Per Unit	Time Setting (s)	Relay Activation Time (s)
0.90	3.00	0.10
0.70	2.40	0.10
0.15	0.10	0.050
0.85	0.075	0.00
1.10	1.00	0.00
1.20	0.20	0.00

3.2. Assumptions

The following assumptions were adopted for the dynamic simulations:

1. Constant maximum and uniform wind speed for the entire period of study.
2. Wind turbine control models with their default values.
3. Under/over voltage/frequency protection use manufacturer settings.

3.3. Faults Simulated

Forty-six (46) faults were considered for the transient stability simulations which included three phase faults, as well as single phase line faults, at the locations defined by SPP. Single-phase line faults were simulated by applying a 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's current practice. Prior queued projects shown in Table 1-1 and units in areas 520, 524, 525, 526, 531, 534, 536, 640, 645, and 650 were monitored in the simulations. Table 3-4 shows the list of simulated contingencies. The table also shows the fault clearing time and the time delay before re-closing for all the study contingencies.

Table 3-4 List of the Simulated Faults

Cont. No.	Cont. Name	Description
1	FLT01-3PH	3 phase fault on the Setab (531465) to Holcomb (531449) 345kV line, near Setab. a. Apply fault at the Setab 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 Setab (531465) to Mingo (531451) 345kV line, near Setab. a. Apply fault at the Setab 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 Setab 345kV (531465) to 115kV (531464) transformer, near the 345 kV bus. a. Apply fault at the Setab 345kV bus. 531259 b. Clear fault after 5 cycles by tripping the faulted transformer.
6	FLT06-1PH	Single phase fault and sequence like previous
7	FLT07-3PH	3 phase fault on the Mingo (531451) to Red Willow (640325) 345kV line, near Mingo. a. Apply fault at the Mingo 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	FLT08-1PH	Single phase fault and sequence like previous
9	FLT09-3PH	3 phase fault on the Mingo 345kV (531451) to 115kV (531429) transformer, near the 345 kV bus. a. Apply fault at the Mingo 345kV bus. 531452 b. Clear fault after 5 cycles by tripping the faulted transformer.
10	FLT10-1PH	Single phase fault and sequence like previous
11	FLT11-3PH	3 phase fault on the Gentleman (640183) to Keystone (640252) 345kV line, near Gentleman. a. Apply fault at the Gentleman 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.

Cont. No.	Cont. Name	Description
12	FLT12-1PH	Single phase fault and sequence like previous
13	FLT13-3PH	3 phase fault on the Gentleman (640183) to Sweetwater (640374) 345kV line, near Gentleman. a. Apply fault at the Gentleman 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 Holcomb (531449) to GEN-2007-040 (531000) 345kV line, near Holcomb. a. Apply fault at the Holcomb 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.
16	FLT16-1PH	Single phase fault and sequence like previous
17	FLT17-3PH	3 phase fault on the Holcomb 345kV (531449) to 115kV (531448) transformer, near the 345 kV bus. a. Apply fault at the Holcomb 345kV bus. 531450 b. Clear fault after 5 cycles by tripping the faulted transformer.
18	FLT18-1PH	Single phase fault and sequence like previous
19	FLT19-3PH	3 phase fault on the Finney (523853) to GEN-2003-013 (560029) 345kV line, 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 Spearville (531469) to Knoll (560004) 345kV line, near Spearville. a. Apply fault at the Spearville 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.
22	FLT22-1PH	Single phase fault and sequence like previous
23	FLT23-3PH	3 phase fault on the Spearville (531469) to Comanche (765341) 345kV line, near Spearville. a. Apply fault at the Spearville 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.
24	FLT24-1PH	Single phase fault and sequence like previous
25	FLT25-3PH	3 phase fault on the Ruleton (531357) to NSI Tap (531356) 115kV line, near Ruleton. a. Apply fault at the Ruleton 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.
26	FLT26-1PH	Single phase fault and sequence like previous

Cont. No.	Cont. Name	Description
27	FLT27-3PH	3 phase fault on the Ruleton (531357) to Lawn Ridge (531368) 115kV line, near Ruleton. a. Apply fault at the Ruleton 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.
28	FLT28-1PH	Single phase fault and sequence like previous
29	FLT29-3PH	3 phase fault on the Ruleton (531357) to Goodland (531443) 115kV line, near Ruleton. a. Apply fault at the Ruleton 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.
30	FLT30-1PH	Single phase fault and sequence like previous
31	FLT31-3PH	3 phase fault on the Tribune Switch (531438) to Selkirk (531434) 115kV line, near Tribune Switch. a. Apply fault at the Tribune Switch 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
32	FLT32-1PH	Single phase fault and sequence like previous
33	FLT33-3PH	3 phase fault on the Tribune Switch (531438) to Syracuse (531437) 115kV line, near Tribune Switch. a. Apply fault at the Tribune Switch 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
34	FLT34-1PH	Single phase fault and sequence like previous
35	FLT35-3PH	3 phase fault on the Syracuse (531437) –Williamson (531440) 115kV line, near Syracuse. a. Apply fault at the Syracuse 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
36	FLT36-1PH	Single phase fault and sequence like previous
37	FLT37-3PH	3 phase fault on the Atwood (530554) –Colby (530555) 115kV line, near Atwood. a. Apply fault at the Atwood 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 Atwood Switch (531364) – Herndon (531367) 115kV line, near Atwood Switch a. Apply fault at the Atwood Switch115kV 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

Cont. No.	Cont. Name	Description
41	FLT39-3PH	3 phase fault on the Tribune Switch (531438) – Palmer (531431) 115kV line, near Tribune a. Apply fault at the Tribune Switch 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
42	FLT40-1PH	Single phase fault and sequence like previous
43	FLT41-3PH	3 phase fault on the Colby (530555) – Hoxie (530556) 115kV line, near Colby a. Apply fault at the Colby 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.
44	FLT42-1PH	Single phase fault and sequence like previous
45	FLT43-3PH	3 phase fault on the Mingo (531429) – Pheasant Run (530559) 115kV line, near Mingo a. Apply fault at the Mingo 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.
46	FLT44-1PH	Single phase fault and sequence like previous

Simulations were performed with a 0.5-second steady-state run followed by the appropriate disturbance as described in Table 3-4. Simulations were run for a minimum 10-second duration to confirm proper machine damping.

3.4. Simulation Results

The simulations conducted in the study using the Siemens 2.3 MW WTGs did not result to any angular or voltage instability problems for the 46 disturbances. The study finds that the interconnection of the proposed 101 MW Project does not impact stability performance of the SPP system for the contingencies tested on the supplied base cases. Table 3-5 presents the results of the dynamic simulations.

Table 3-5 Results of the Simulated Faults

Cont. No.	Description	Results for 10SP and 09WP
1	3 phase fault on the Setab (531465) to Holcomb (531449) 345kV line, near Setab. a. Apply fault at the Setab 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.	Stable
2	Single phase fault and sequence like previous	Stable

Cont. No.	Description	Results for 10SP and 09WP
3	3 phase fault on the Setab (531465) to Mingo (531451) 345kV line, near Setab. a. Apply fault at the Setab 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.	Stable
4	Single phase fault and sequence like previous	Stable
5	3 phase fault on the Setab 345kV (531465) to 115kV (531464) transformer, near the 345 kV bus. a. Apply fault at the Setab 345kV bus. 531259 b. Clear fault after 5 cycles by tripping the faulted transformer.	Stable
6	Single phase fault and sequence like previous	Stable
7	3 phase fault on the Mingo (531451) to Red Willow (640325) 345kV line, near Mingo. a. Apply fault at the Mingo 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.	Stable
8	Single phase fault and sequence like previous	Stable
9	3 phase fault on the Mingo 345kV (531451) to 115kV (531429) transformer, near the 345 kV bus. a. Apply fault at the Mingo 345kV bus. 531452 b. Clear fault after 5 cycles by tripping the faulted transformer.	Stable
10	Single phase fault and sequence like previous	Stable
11	3 phase fault on the Gentleman (640183) to Keystone (640252) 345kV line, near Gentleman. a. Apply fault at the Gentleman 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.	Stable
12	Single phase fault and sequence like previous	Stable
13	3 phase fault on the Gentleman (640183) to Sweetwater (640374) 345kV line, near Gentleman. a. Apply fault at the Gentleman 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.	Stable
14	Single phase fault and sequence like previous	Stable

Cont. No.	Description	Results for 10SP and 09WP
15	3 phase fault on the Holcomb (531449) to GEN-2007-040 (531000) 345kV line, near Holcomb. a. Apply fault at the Holcomb 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.	Stable
16	Single phase fault and sequence like previous	Stable
17	3 phase fault on the Holcomb 345kV (531449) to 115kV (531448) transformer, near the 345 kV bus. a. Apply fault at the Holcomb 345kV bus. 531450 b. Clear fault after 5 cycles by tripping the faulted transformer.	Stable
18	Single phase fault and sequence like previous	Stable
19	3 phase fault on the Finney (523853) to GEN-2003-013 (560029) 345kV line, 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.	Stable
20	Single phase fault and sequence like previous	Stable
21	3 phase fault on the Spearville (531469) to Knoll (560004) 345kV line, near Spearville. a. Apply fault at the Spearville 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.	Stable
22	Single phase fault and sequence like previous	Stable
23	3 phase fault on the Spearville (531469) to Comanche (765341) 345kV line, near Spearville. a. Apply fault at the Spearville 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.	Stable
24	Single phase fault and sequence like previous	Stable
25	3 phase fault on the Ruleton (531357) to NSI Tap (531356) 115kV line, near Ruleton. a. Apply fault at the Ruleton 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.	Stable
26	Single phase fault and sequence like previous	Stable

Cont. No.	Description	Results for 10SP and 09WP
27	3 phase fault on the Ruleton (531357) to Lawn Ridge (531368) 115kV line, near Ruleton. a. Apply fault at the Ruleton 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.	Stable
28	Single phase fault and sequence like previous	Stable
29	3 phase fault on the Ruleton (531357) to Goodland (531443) 115kV line, near Ruleton. a. Apply fault at the Ruleton 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.	Stable
30	Single phase fault and sequence like previous	Stable
31	3 phase fault on the Tribune Switch (531438) to Selkirk (531434) 115kV line, near Tribune Switch. a. Apply fault at the Tribune Switch 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable
32	Single phase fault and sequence like previous	Stable
33	3 phase fault on the Tribune Switch (531438) to Syracuse (531437) 115kV line, near Tribune Switch. a. Apply fault at the Tribune Switch 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable
34	Single phase fault and sequence like previous	Stable
35	3 phase fault on the Syracuse (531437) –Williamson (531440) 115kV line, near Syracuse. a. Apply fault at the Syracuse 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable
36	Single phase fault and sequence like previous	Stable

Cont. No.	Description	Results for 10SP and 09WP
37	3 phase fault on the Atwood (530554) –Colby (530555) 115kV line, near Atwood. a. Apply fault at the Atwood 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.	Stable
38	Single phase fault and sequence like previous	Stable
39	3 phase fault on the Atwood Switch (531364) – Herndon (531367) 115kV line, near Atwood Switch a. Apply fault at the Atwood Switch115kV 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.	Stable
40	Single phase fault and sequence like previous	Stable
41	3 phase fault on the Tribune Switch (531438) – Palmer (531431) 115kV line, near Tribune a. Apply fault at the Tribune Switch 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.	Stable
42	Single phase fault and sequence like previous	Stable
43	3 phase fault on the Colby (530555) – Hoxie (530556) 115kV line, near Colby a. Apply fault at the Colby 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.	Stable
44	Single phase fault and sequence like previous	Stable
45	3 phase fault on the Mingo (531429) – Pheasant Run (530559) 115kV line, near Mingo a. Apply fault at the Mingo 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.	Stable
46	Single phase fault and sequence like previous	Stable

Section 4. Conclusions

The findings of the impact study for the proposed interconnection of DISIS-2009-001 (Group 4) consisting of project Gen-2008-025, considered 100% at the proposed 101 MW installed capacity, are:

1. The results of the Power Factor analysis showed that with the study Project must maintain a power factor range in which they are supplying or absorbing vars at the point of interconnection in accordance with the requirements in Section 2.
2. Using Siemens 2.3 MW WTGs, the stability simulations for 46 specified test disturbances did not result to any angular or voltage instability problems in the SPP system. The study finds that the interconnection of the proposed 101 MW Project does not impact stability performance of the SPP system for the contingencies tested on the supplied base cases.

M: Stability Study for Group 5

R189-09

Generator Interconnection Impact Study for DISIS-2009-001 - Group 5 - Draft

Prepared for

Southwest Power Pool, Inc.

Submitted by:
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Draft Report: January 6, 2010

Siemens PTI Project Number: P/23-115068-B-1

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Section

1

Introduction

1.1 Background

Pursuant to the tariff and at the request of the Southwest Power Pool (SPP), Siemens PTI performed the following Impact Study to satisfy the Impact Study Agreement executed by the requesting customers and SPP for SPP Generation Interconnection request. The requests for interconnection were placed with SPP in accordance to SPP's Open Access Transmission Tariff, which covers new generation interconnections on SPP's transmission system.

The purpose of this report is to present the results of the stability and power factor analysis performed to evaluate the impact of the proposed GEN-2008-051 project on the Southwest Power Pool system. Eventual indicative solutions to the identified issues are proposed based on the impact of the project on the Southwest Power Pool system. Section 2 describes the proposed wind project in detail.

Transient stability analysis was performed using the package provide by SPP. It contains the latest stability database in PSS®E version 30.3.3. The stability package also includes the dynamic data for the previously queued projects.

1.2 Purpose

The steady state and stability study was carried out to:

(a) Determine the ability of the proposed generation facility to remain in synchronism and within applicable planning standards following system faults with unsuccessful reclosing.

(b) Determine the amount of transient support required from the costumer to meet the power factor requirement at the POI.

(c) Determine the ability of the wind farm to meet FERC Order 661A (low voltage ride through and wind farm recovery to pre-fault voltage) with and without additional reactive support.

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Section

2

Model Development

The study has considered the 2010 Summer Peak and 2009 Winter Peak load flow models provided by SPP with the required interconnection generations modeled. The base cases also contain all the significant previous queued generation interconnection projects in the interconnection queue.

2.1 Power Flow Data

The Group 5 of DISIS-2009-001 contains one proposed wind generation project. Table 2-1 presents the size of the wind generation project, the Wind Turbine Generator (WTG) manufacturer, the reactive capability of the wind farm as well as the point of interconnection and the PSS®E bus number in the load flow models.

Table 2-1 – Details of the Interconnection Requests

			Reactive Capability of Wind Farm			
Request	Size (MW)	Model	Max (MVAR)	Min (MVAR)	Point of Interconnection	Bus Number
GEN-2008-051	322	Siemens 2.3MW	155.95	-155.95	Potter 345kV	523961

The analysis was carried out using the database package provided by SPP which also includes the modeling data for the previously queued projects, as shown in Table 2-2:

Table 2-2 – Details of the Prior Queued Interconnection Requests

Request	Size (MW)	Model	Point of Interconnection	Bus Number
GEN-2002-022	240	Siemens 2.3MW	Bushland 230kV	524267
GEN-2004-003	240	GE 1.5MW	Conway 115kV	524079
GEN-2005-021	85.5	GE 1.5MW	Kirby 115kV	524088
GEN-2006-039	400	Clipper 2.5MW	Buffalo Lk 230kV	560009
GEN-2006-045	240	Suzlon 2.1MW	Buffalo Lk 230kV	560009
GEN-2006-047	240	Suzlon 2.1 MW	Buffalo Lk 230kV	560009

GEN-2007-002	160	Steam Turbine	Grapevine 115kV	523770
GEN-2007-008	300	Suzlon 2.1 MW	Grapevine 230kV	523771
GEN-2007-045	171	G.E. 1.5MW	Conway 115kV	524079
GEN-2007-048	400	Furhlander	Amarillo South – Swisher 230kV line	525228

Figures 2-1 and 2-2 present the surrounding area of the Group 5 point of interconnection, showing the line flows and voltage profile for the load flow models considered in the study for summer and winter peak scenarios, respectively.

Figure 2-1 - Group 5 Point of Interconnection Surrounding Area – Summer Peak

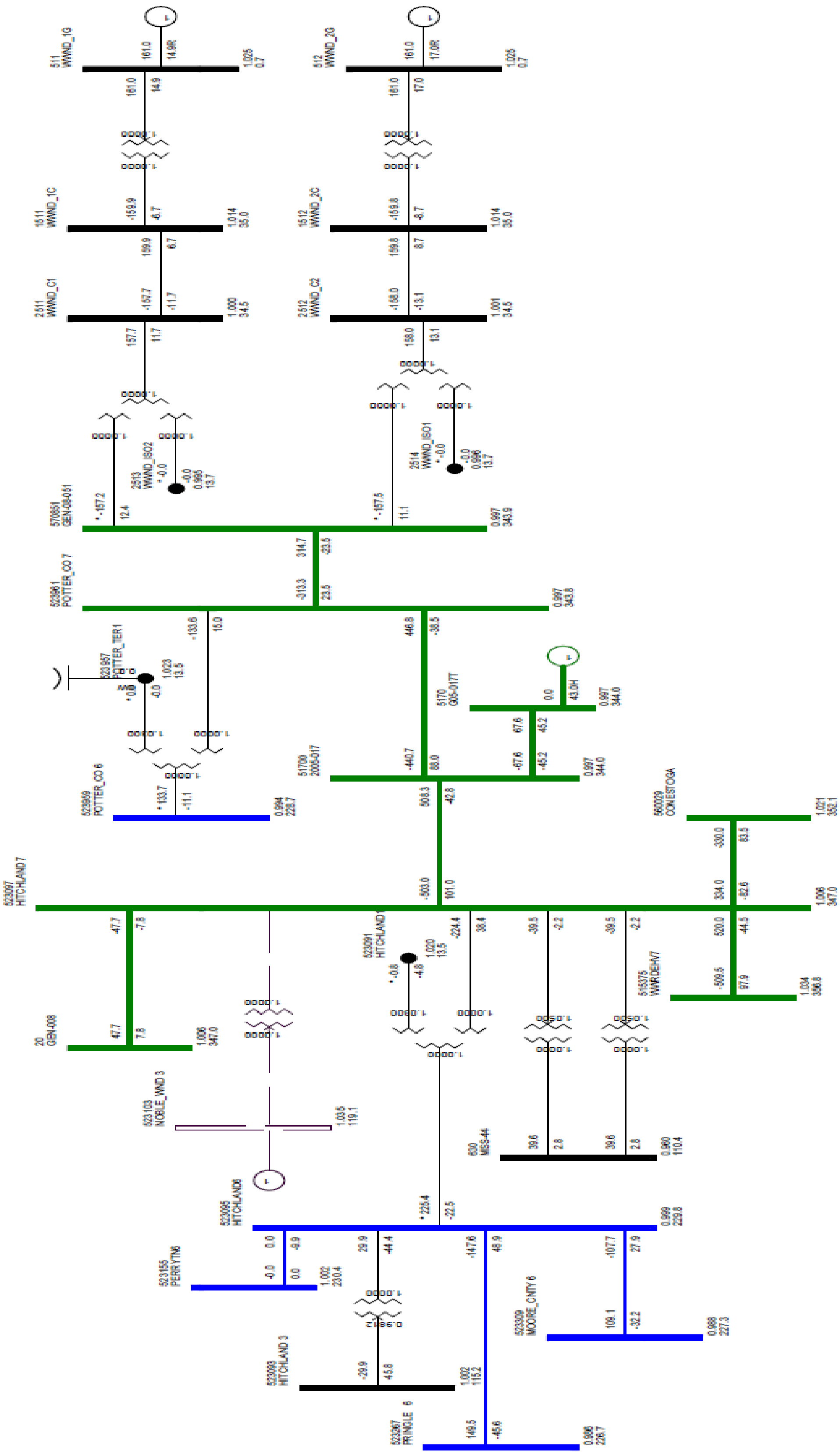


Figure 2-2 - Group 5 Points of Interconnection Surrounding Area – Winter Peak

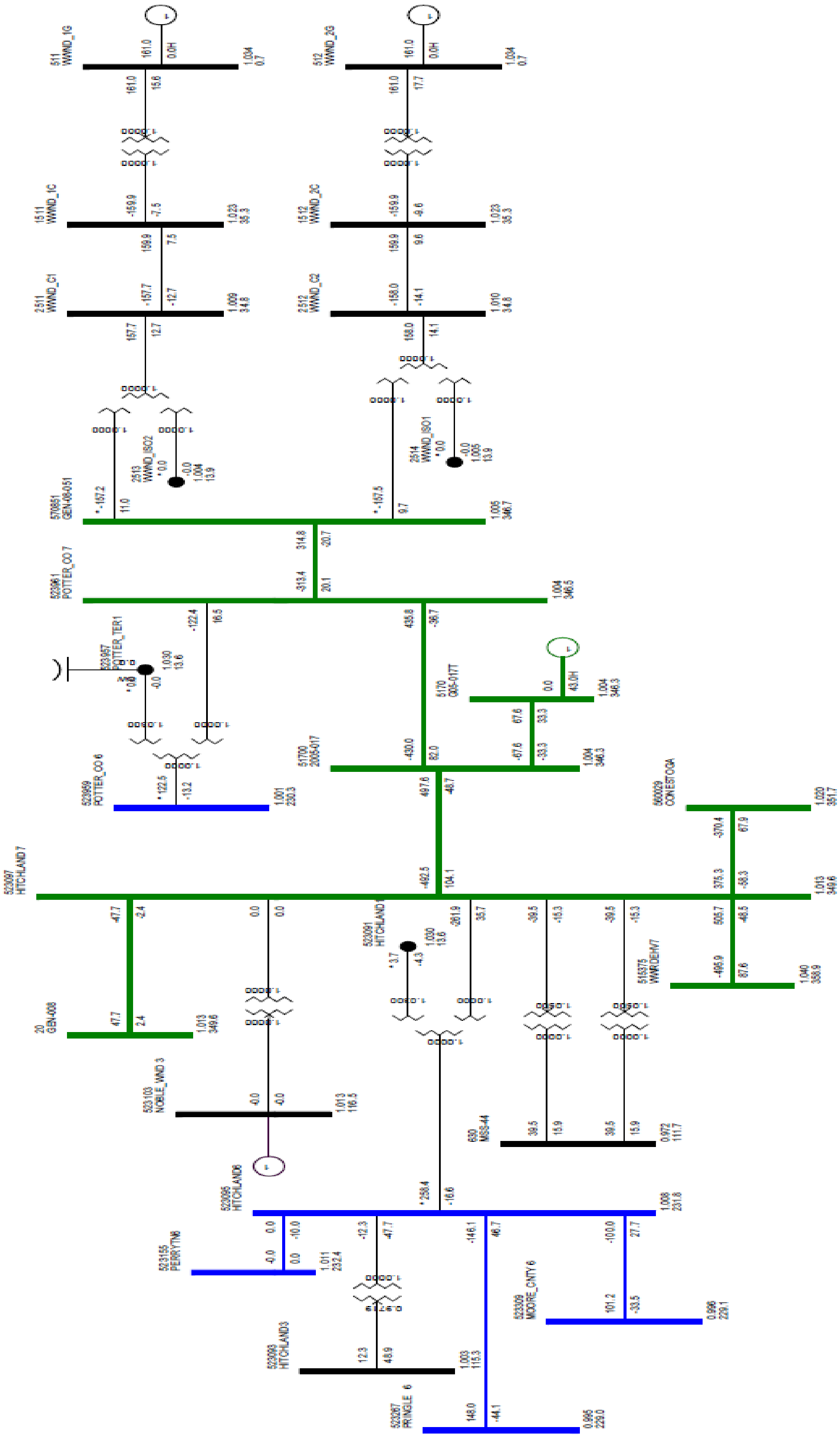


Figure A-1 in Appendix A presents the single line diagram, showing the modeling details of the interconnecting project.

2.2 Stability Database

The transient stability analysis was performed using the data provided by SPP. Stability models for the Group 5 interconnection requests were already added to the dynamic database. All turbine parameters used in the simulation models are the default parameters in the wind turbine package. It is assumed that each wind turbine generators (WTGs) would be controlling the voltage of its own bus.

The default voltage protection model set points recommended by the manufacturer were used. The wind units were modeled with their built-in voltage ride through capability. Also, the default frequency protection model set points recommended by the manufacturer were used.

The PSS®E dynamic models output list is shown in Appendix B, documenting the model parameters for the Group 5 wind turbines modeled in the stability study.

Section

3

Methodology and Assumptions

The study considered the 2010 summer peak and 2009 winter peak power flow cases with the required interconnection generation requests modeled as described in Section 2. The base case also contains all the significant previous queued projects in the interconnection queue.

The monitored areas in this study are shown in Table 3-1.

Table 3-1 – Areas of Interest

Area Number	Area Name
520	AEPW
524	OKGE
525	WFEC
526	SPS
531	MIDW
534	SUNC
536	WERE

3.1 Methodology

3.1.1 Stability Simulations

The dynamic simulations were performed using the PSS®E version 30.3.3 with the latest stability database provided by SPP. Three-phase faults and single-phase faults in the neighborhood of DISIS-2009-001 – Group 5 Point of interconnection were simulated. Any adverse impact on the system stability was documented and further investigated with appropriate solutions to determine whether a static or dynamic VAR device is required or not.

3.1.2 Steady State Simulations

3.1.2.1 N-1 Contingency Analysis

An N-1 contingency analysis was performed to evaluate voltage violations, if any, caused by disturbances (tripping of the faulted line). The voltages at each POI were monitored for deviations from the base case voltage and the percentage deviations were documented.

The summer peak and winter peak load flow cases were adjusted to ensure there are no relevant pre contingency voltage criteria violations. During contingency analysis, voltages of any monitored bus found to be outside the range of the post-contingency criteria and having more than 1% of project impact were reported.

3.1.2.2 Power Factor Analysis

A QV analysis was performed to determine the reactive support requirement at the project's POI. QV curves, plotted for base case and contingency conditions, are used to determine the reactive power support required at Potter 345 kV POI, in order to maintain the bus scheduled pre contingency voltages.

These curves are obtained through a series of AC load flow calculations. Starting with no reactive support at a bus, the voltage is computed for a series of power flows as the reactive support is increased in steps, until the power flow experiences convergence difficulties as the system approaches the voltage collapse point.

3.2 Disturbances for Stability Analysis

The stability simulations considered three-phase (3PH) faults and single line-to-ground (SLG) faults. For all contingencies the fault complete clearing process includes the following sequence of events:

1) Line fault, cleared after 5 cycles by tripping the both line terminals

2) After 20 cycles the line is reclosed unsuccessfully (reclosing under fault conditions)

3) The fault is cleared by tripping both ends of the faulted line again, 5 cycles later.

The disturbances evaluated are listed in the following Table 3-2:

Table 3-2: Disturbances for Stability Analysis

#	Fault Location	Fault Type	Clearing	Fault Clearing
1	At Potter Co. end of 345kV line to GEN-2005-017	3PH	Unsuccessful Reclosing	trip Potter Co. - GEN-2005-017 345kV line
2	At Potter Co. end of 345kV line to GEN-2005-017	SLG	Unsuccessful Reclosing	trip Potter Co. - GEN-2005-017 345kV line
3	At GEN-2003-013 end of 345kV line to Hitchland	3PH	Unsuccessful Reclosing	trip GEN-2003-013 - Hitchland 345kV line
4	At GEN-2003-013 end of 345kV line to Hitchland	SLG	Unsuccessful Reclosing	trip GEN-2003-013 - Hitchland 345kV line
5	At 345kV end of Potter Co. 345/230 kV transformer	3PH	Unsuccessful Reclosing	trip Potter Co. 345/230 kV transformer
6	At 345kV end of Potter Co. 345/230 kV transformer	SLG	Unsuccessful Reclosing	trip Potter Co. 345/230 kV transformer
7	At Lawton Eastside end of 345kV line to Sunnyside	3PH	Unsuccessful Reclosing	trip Lawton Eastside - Sunnyside 345kV line

8	At Lawton Eastside end of 345kV line to Sunnyside	SLG	Unsuccessful Reclosing	trip Lawton Eastside - Sunnyside 345kV line
9	At Grapevine end of 230kV line to Wheeler	3PH	Unsuccessful Reclosing	trip Grapevine - Wheeler 230kV line
10	At Grapevine end of 230kV line to Wheeler	SLG	Unsuccessful Reclosing	trip Grapevine - Wheeler 230kV line
11	At Tolk end of 230kV line to Tuco	3PH	Unsuccessful Reclosing	trip Tolk - Tuco 230kV line
12	At Tolk end of 230kV line to Tuco	SLG	Unsuccessful Reclosing	trip Tolk - Tuco 230kV line
13	At 230kV end of Tuco 345/230 kV transformer	3PH	Unsuccessful Reclosing	trip Tuco 230/345 kV transformer
14	At 230kV end of Tuco 345/230 kV transformer	SLG	Unsuccessful Reclosing	trip Tuco 230/345 kV transformer
15	At GEN-2005-015 end of 345kV line to Oklaunion	3PH	Unsuccessful Reclosing	trip GEN-2005-015 - Oklaunion 345kV line
16	At GEN-2005-015 end of 345kV line to Oklaunion	SLG	Unsuccessful Reclosing	trip GEN-2005-015 - Oklaunion 345kV line
17	At Oklaunion end of 345kV line to Lawton Eastside	3PH	Unsuccessful Reclosing	trip Oklaunion - Lawton Eastside 345kV line
18	At Oklaunion end of 345kV line to Lawton Eastside	SLG	Unsuccessful Reclosing	trip Oklaunion - Lawton Eastside 345kV line
19	At Grapevine end of 230kV line to Nichols	3PH	Unsuccessful Reclosing	trip Grapevine - Nichols 230kV line
20	At Grapevine end of 230kV line to Nichols	SLG	Unsuccessful Reclosing	trip Grapevine - Nichols 230kV line
21	At Conway end of 115kV line to Yarnell	3PH	Unsuccessful Reclosing	trip Conway - Yarnell 115kV line
22	At Conway end of 115kV line to Yarnell	SLG	Unsuccessful Reclosing	trip Conway - Yarnell 115kV line
23	At Conway end of 115kV line to Kirby	3PH	Unsuccessful Reclosing	trip Conway - Kirby 115kV line
24	At Conway end of 115kV line to Kirby	SLG	Unsuccessful Reclosing	trip Conway - Kirby 115kV line
25	At 230 kV end of Wheeler 345/230 kV transformer	3PH	Unsuccessful Reclosing	trip Wheeler 230/345 kV transformer
26	At 230 kV end of Wheeler 345/230 kV transformer	SLG	Unsuccessful Reclosing	trip Wheeler 230/345 kV transformer
27	At Wheeler/Midpoint end of 345kV line to Anadarko	3PH	Unsuccessful Reclosing	trip Wheeler/Midpoint - Anadarko 345kV line
28	At Wheeler/Midpoint end of 345kV line to Anadarko	SLG	Unsuccessful Reclosing	trip Wheeler/Midpoint - Anadarko 345kV line
29	At 115 kV end of Conway 345/115 kV transformer	3PH	Unsuccessful Reclosing	trip Conway 115/345 kV transformer
30	At 115 kV end of Conway 345/115 kV transformer	SLG	Unsuccessful Reclosing	trip Conway 115/345 kV transformer
31	At Conway end of 345kV line to Wheeler/Midpoint	3PH	Unsuccessful Reclosing	trip Conway - Wheeler/Midpoint 345kV line
32	At Conway end of 345kV line to Wheeler/Midpoint	SLG	Unsuccessful Reclosing	trip Conway - Wheeler/Midpoint 345kV line
33	At 230 kV end of Grapevine 230/115 kV transformer	3PH	Unsuccessful Reclosing	trip Grapevine 230/115 kV transformer

34	At 230 kV end of Grapevine 230/115 kV transformer	SLG	Unsuccessful Reclosing	trip Grapevine 230/115 kV transformer
35	At Tuco end of 345kV line to Wheeler/Midpoint	3PH	Unsuccessful Reclosing	trip Tuco - Wheeler/Midpoint 345kV line
36	At Tuco end of 345kV line to Wheeler/Midpoint	SLG	Unsuccessful Reclosing	trip Tuco - Wheeler/Midpoint 345kV line
37	At Wheeler/Midpoint end of 345kV line to Woodward	3PH	Unsuccessful Reclosing	trip Wheeler/Midpoint - Woodward 345kV line
38	At Wheeler/Midpoint end of 345kV line to Woodward	SLG	Unsuccessful Reclosing	trip Wheeler/Midpoint - Woodward 345kV line
39	At Kirby end of 115kV line to McClellan	3PH	Unsuccessful Reclosing	trip Kirby - McClellan 115kV line
40	At Kirby end of 115kV line to McClellan	SLG	Unsuccessful Reclosing	trip Kirby - McClellan 115kV line
41	At Potter end of 230kV line to Moore County	3PH	Unsuccessful Reclosing	trip Potter - Moore County 230kV line
42	At Potter end of 230kV line to Moore County	SLG	Unsuccessful Reclosing	trip Potter - Moore County 230kV line
43	At Potter end of 230kV line to Harrington West	3PH	Unsuccessful Reclosing	trip Potter - Harrington West 230kV line
44	At Potter end of 230kV line to Harrington West	SLG	Unsuccessful Reclosing	trip Potter - Harrington West 230kV line
45	At Potter end of 230kV line to Bushland	3PH	Unsuccessful Reclosing	trip Potter - Bushland 230kV line
46	At Potter end of 230kV line to Bushland	SLG	Unsuccessful Reclosing	trip Potter - Bushland 230kV line
47	At Potter end of 230kV line to GEN-2006-039	3PH	Unsuccessful Reclosing	trip Potter - GEN-2006-039 230kV line
48	At Potter end of 230kV line to GEN-2006-039	SLG	Unsuccessful Reclosing	trip Potter - GEN-2006-039 230kV line

In order to simulate single line to ground faults, equivalent reactances were determined to be applied at the buses. Table 3-3 presents the equivalent reactances obtained for the summer peak case and Table 3-4 presents the equivalent reactance for the winter peak case.:

Table 3-3: Equivalent Reactances – Line to Ground Faults – Summer Peak

BUS	Equivalent Reactance (Mvar)
523961	2400
560029	2600
511468	3800
523771	1800
525524	6800
525832	2800

BUS	Equivalent Reactance (Mvar)
560813	1900
511456	1600
524079	1400
525835	3200
560000	1400
525832	2800
525835	3200
524088	800
523959	4500
525830	3100
523777	2500

Table 3-4: Equivalent Reactances – Line to Ground Faults – Winter Peak

BUS	Equivalent Reactance (Mvar)
523961	2350
560029	2600
511468	3800
523771	1900
525524	5500
525832	2800
560813	1900
511456	1600
524079	1400
525835	3300
560000	1500
525832	2800
525835	3300

BUS	Equivalent Reactance (Mvar)
524088	800
523959	3950
525830	3000
523777	2700

The following Figures 3-1 and 3-2 present the fault locations within the study area.

Figure 3-1 – Fault Locations in the Study Area – *Diagram1*

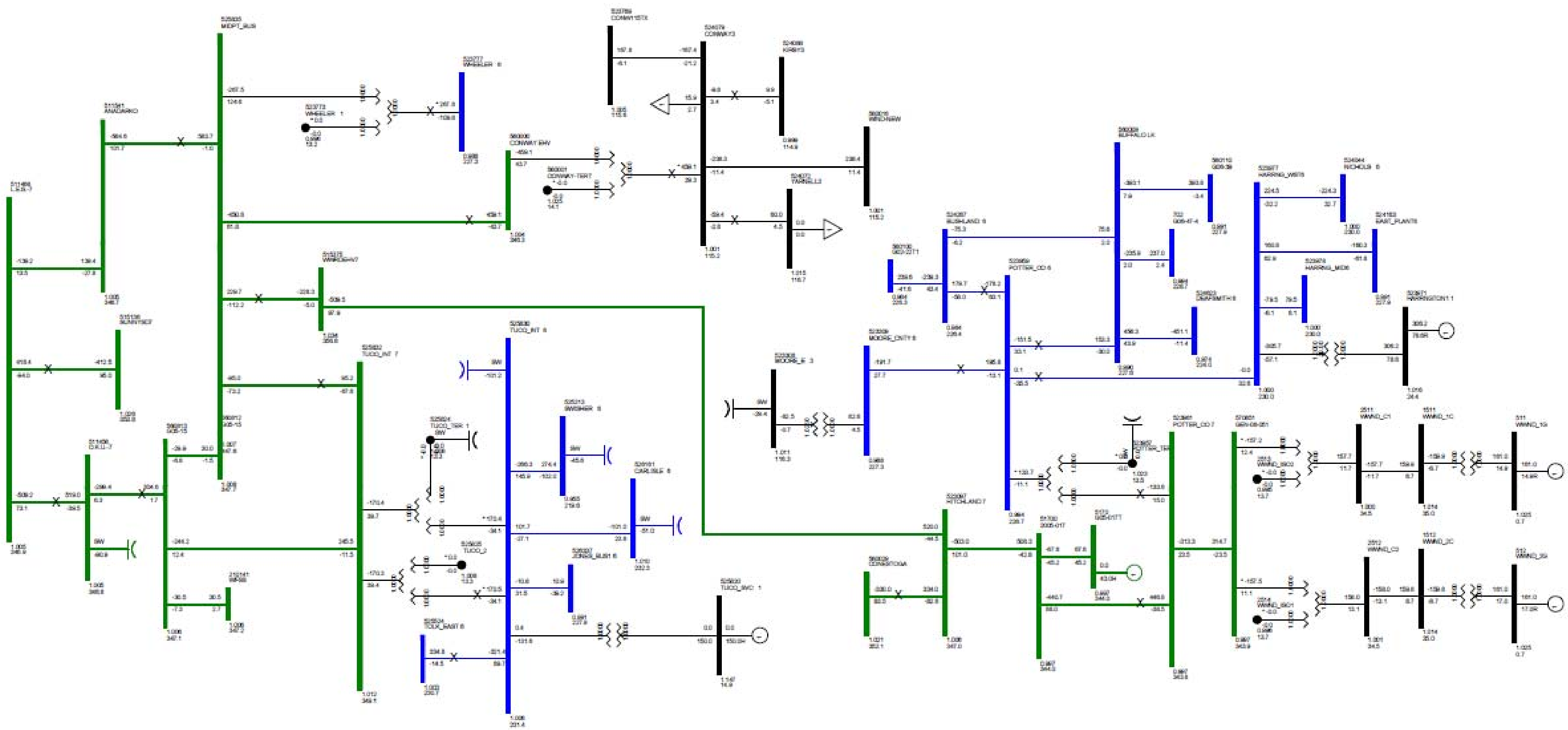
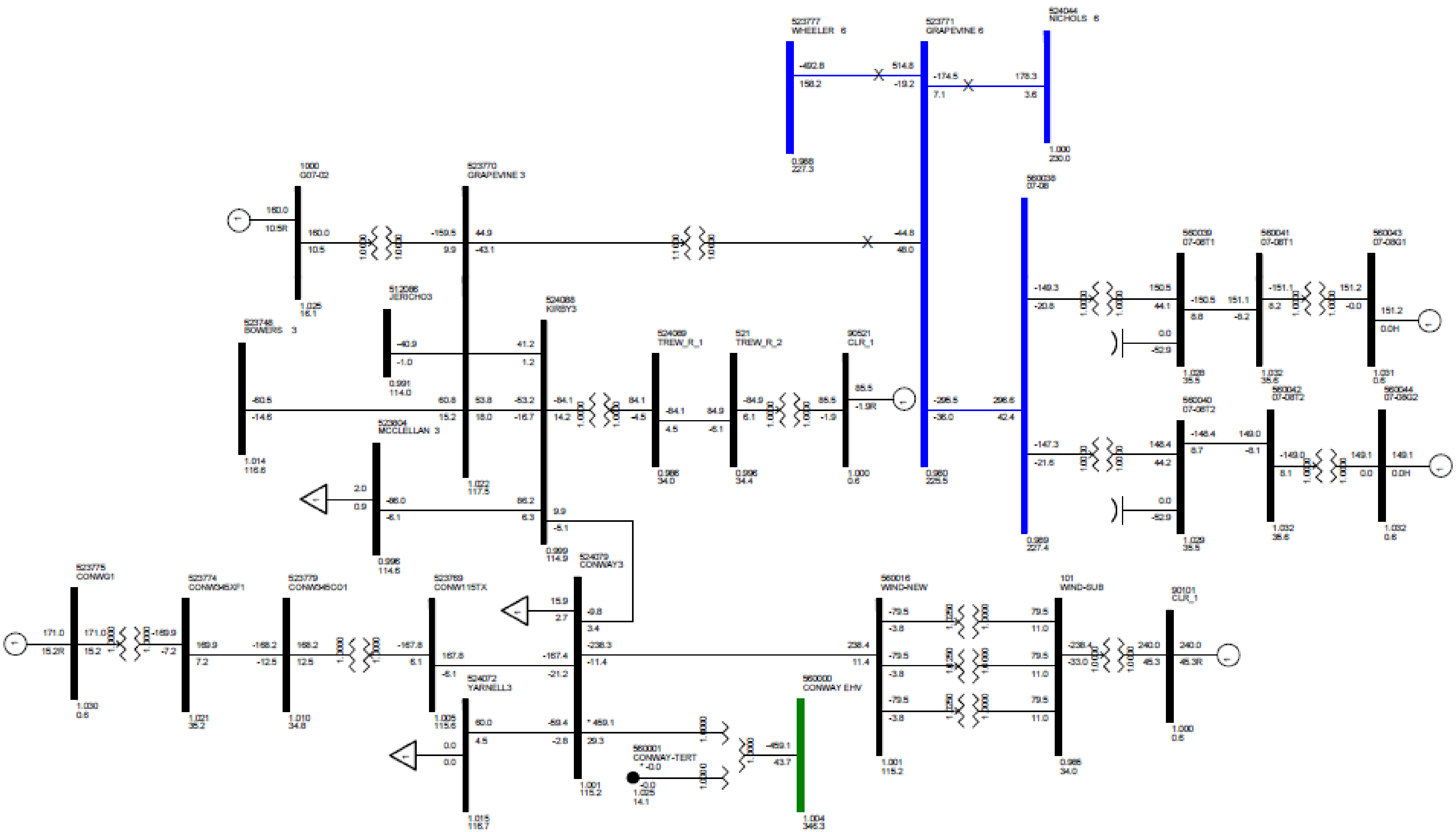


Figure 3-2 – Fault Locations in the Study Area – *Diagram2*



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Section

4

Analysis Performed

4.1 Steady State Performance

Table 4-1 and Table 4-2 summarize the results obtained from the steady state analysis for Summer Peak and Winter Peak base cases, respectively. The tables list the voltage deviations at the Points of Interconnection of the proposed study projects of Group 5, as well as the prior queued projects. Note that only the contingencies that cause a voltage criterion violation or have an impact of at least 1% in the POI's voltages are listed.

The complete set of results for both summer peak and winter peak scenarios are presented in Appendix C.

Table 4-1: Results Obtained – Steady State Analysis – Summer Peak Base Case

Bus #	Bus Name	Base kV	Contingency Voltage	Base Voltage	%Deviation
Base Case					
523770	GRAPEVINE 3	115.0	-	1.0216	-
523771	GRAPEVINE 6	230.0	-	0.9802	-
523961	POTTER_CO 7	345.0	-	0.9966	-
524079	CONWAY3	115.0	-	1.0014	-
524088	KIRBY3	115.0	-	0.9988	-
524267	BUSHLAND 6	230.0	-	0.9844	-
525228	07-048	230.0	-	0.9621	-
560009	BUFFALO LK	230.0	-	0.9896	-
FLT 01					
523771	GRAPEVINE 6	230.0	0.9619	0.9802	-1.87%
FLT 03					
523771	GRAPEVINE 6	230.0	0.9604	0.9802	-2.02%
524079	CONWAY3	115.0	0.9904	1.0014	-1.10%
FLT 05					
523961	POTTER_CO 7	345.0	1.0130	0.9966	1.65%
FLT 09					
523771	GRAPEVINE 6	230.0	0.9971	0.9802	1.72%

523961	POTTER_CO 7	345.0	0.9859	0.9966	-1.07%
524079	CONWAY3	115.0	0.9750	1.0014	-2.64%
524088	KIRBY3	115.0	0.9741	0.9988	-2.47%
525228	07-048	230.0	0.9516	0.9621	-1.09%
FLT 15					
523771	GRAPEVINE 6	230.0	0.9645	0.9802	-1.60%
FLT 17					
523770	GRAPEVINE 3	115.0	1.0053	1.0216	-1.60%
523771	GRAPEVINE 6	230.0	0.9447	0.9802	-3.62%
523961	POTTER_CO 7	345.0	0.9844	0.9966	-1.22%
524079	CONWAY3	115.0	0.9819	1.0014	-1.95%
524088	KIRBY3	115.0	0.9777	0.9988	-2.11%
FLT 19					
523771	GRAPEVINE 6	230.0	1.0022	0.9802	2.24%
FLT 25					
523771	GRAPEVINE 6	230.0	0.9703	0.9802	-1.01%
FLT 29					
523770	GRAPEVINE 3	115.0	0.9851	1.0216	-3.57%
523771	GRAPEVINE 6	230.0	0.9424	0.9802	-3.86%
524079	CONWAY3	115.0	1.0184	1.0014	1.70%
524088	KIRBY3	115.0	0.9676	0.9988	-3.12%
FLT 31					
523770	GRAPEVINE 3	115.0	0.9829	1.0216	-3.79%
523771	GRAPEVINE 6	230.0	0.9352	0.9802	-4.59%
524079	CONWAY3	115.0	1.0180	1.0014	1.66%
524088	KIRBY3	115.0	0.9659	0.9988	-3.29%
FLT 33					
523770	GRAPEVINE 3	115.0	1.0017	1.0216	-1.95%
523771	GRAPEVINE 6	230.0	1.0031	0.9802	2.34%
524088	KIRBY3	115.0	0.9836	0.9988	-1.52%
FLT 35					
523771	GRAPEVINE 6	230.0	0.9664	0.9802	-1.41%
FLT 37					
523771	GRAPEVINE 6	230.0	0.9702	0.9802	-1.02%
FLT 45					
524267	BUSHLAND 6	230.0	0.9570	0.9844	-2.78%
560009	BUFFALO LK	230.0	0.9737	0.9896	-1.61%

Table 4-2: Results Obtained – Steady State Analysis – Winter Peak Base Case

Bus #	Bus Name	Base kV	Contingency Voltage	Base Voltage	%Deviation
Base Case					
523770	GRAPEVINE 3	115.0	-	1.0360	-
523771	GRAPEVINE 6	230.0	-	1.0004	-
523961	POTTER_CO 7	345.0	-	1.0042	-
524079	CONWAY3	115.0	-	1.0173	-
524088	KIRBY3	115.0	-	1.0115	-
524267	BUSHLAND 6	230.0	-	1.0036	-
525228	07-048	230.0	-	0.9810	-
560009	BUFFALO LK	230.0	-	1.0166	-
FLT 01					
523771	GRAPEVINE 6	230.0	0.9850	1.0004	-1.54%
523961	POTTER_CO 7	345.0	0.9916	1.0042	-1.25%
524079	CONWAY3	115.0	1.0071	1.0173	-1.00%
FLT 03					
523771	GRAPEVINE 6	230.0	0.9838	1.0004	-1.66%
524079	CONWAY3	115.0	1.0054	1.0173	-1.17%
FLT 05					
523961	POTTER_CO 7	345.0	1.0293	1.0042	2.50%
FLT 09					
524079	CONWAY3	115.0	0.9948	1.0173	-2.21%
524088	KIRBY3	115.0	0.9877	1.0115	-2.35%
FLT 15					
523771	GRAPEVINE 6	230.0	0.9870	1.0004	-1.34%
FLT 17					
523770	GRAPEVINE 3	115.0	1.0216	1.0360	-1.39%
523771	GRAPEVINE 6	230.0	0.9723	1.0004	-2.81%
523961	POTTER_CO 7	345.0	0.9922	1.0042	-1.19%
524079	CONWAY3	115.0	0.9971	1.0173	-1.99%
524088	KIRBY3	115.0	0.9929	1.0115	-1.84%
FLT 19					
523771	GRAPEVINE 6	230.0	1.0335	1.0004	3.31%
FLT 29					
523770	GRAPEVINE 3	115.0	1.0115	1.0360	-2.36%
523771	GRAPEVINE 6	230.0	0.9758	1.0004	-2.46%
524079	CONWAY3	115.0	1.0350	1.0173	1.74%

524088	KIRBY3	115.0	0.9950	1.0115	-1.63%
FLT 31					
523770	GRAPEVINE 3	115.0	1.0097	1.0360	-2.54%
523771	GRAPEVINE 6	230.0	0.9707	1.0004	-2.97%
524079	CONWAY3	115.0	1.0348	1.0173	1.72%
524088	KIRBY3	115.0	0.9937	1.0115	-1.76%
FLT 33					
523770	GRAPEVINE 3	115.0	1.0150	1.0360	-2.03%
523771	GRAPEVINE 6	230.0	1.0231	1.0004	2.27%
524088	KIRBY3	115.0	0.9969	1.0115	-1.44%
FLT 35					
523771	GRAPEVINE 6	230.0	0.9882	1.0004	-1.22%

Although some contingencies cause voltage rise or drop equal to or greater than 0.01 p.u, the voltage profile of the POI's surrounding area remains within the limits. The exceptions are observed in the Summer Case where the voltage of the Grapevine 230 kV bus 523771 falls below 0.95 pu for contingencies FLT 17, FLT 29, and FLT 31.

The Group 5 projects have significant impact on the voltages of the buses monitored in the study system, either in base case conditions or under contingencies. However, no significant voltage criteria violations were identified through the simulations performed.

4.2 Power Factor Analysis

A QV analysis was performed to determine the amount of reactive support required to maintain the scheduled voltages at the Potter 345 kV point of interconnection. The contingencies described in Table 3-2 were evaluated in steady state conditions for summer and winter peak base cases, with variable Mvar injection at the POIs.

Table 4-3 presents the Mvar requirements and the associated power factor that the Wind Project must be able to provide under contingencies.

Table 4-3: Mvar Requirements and Power Factor at the POI for the Proposed Projects Interconnection

Project	Point of Interconnection	V Scheduled (p.u)	Mvar Requirements at POI	Contingency	Power Factor at POI (lagging - supplying vars)
GEN-2008-051	Potter 345 kV	0.997	88 Mvar	FLT 17	0.9627

4.3 Dynamic Results

The stability analysis was carried out using both Summer Peak and Winter Peak load flow models.

In order to determine the impact of the project on the overall system dynamics as well as to determine the requirements to meet the FERC Order 661-A Guidelines, 48 contingencies listed in Table 3-2 were simulated. The results obtained are described in this sub-section.

Table 4-4 and Table 4-5 summarize the results obtained from the stability simulations for Summer Peak and Winter Peak base cases, respectively. Note that only the critical contingencies that lead to trips due to LVRT or loss of synchronism are listed.

Table 4-4: Results Obtained – Summer Peak Base Case

Name	Wind Projects Dynamic Performance
FLT11-3PH	GEN-2005-010 (560817 & 560818) tripped for low voltage at 0.6 s
FLT15-3PH	GEN-2005-015 (560811) tripped for low voltage at 0.633 s

Table 4-5: Results Obtained – Winter Peak Base Case

Name	Wind Projects Dynamic Performance
FLT11-3PH	GEN-2005-010 (560817 & 560818) tripped for low voltage at 0.6 s

The Gen-2008-051 project does not trip for any of the disturbances studied. The Gen-2005-010 project i.e. machines at bus 560817 and bus 560818 trips on low voltage for FLT-11 three phase fault. Since the project is an older project and is not in the current study group or interconnection queue, no further remediation solutions will be attempted. Similarly the Gen-2005-015 project i.e. Machine 1 at bus 560811 trips for low voltage in the Summer Peak case for FLT-15 three phase fault.

Section

5

Conclusions

The Wind Project in Group 5 has been evaluated to determine the system requirements to meet the requirements associated with FERC Order 661-A Guidelines for Low Voltage Ride Through (LVRT) and therefore, for it to deliver its full power to the SPP transmission system.

Steady state and stability analysis were carried out to evaluate the system performance under contingencies

In general the Group 5 project has significant impact on the voltage profile of the monitored system, either in base case conditions or under contingencies. However, no significant voltage criteria violations were identified through the simulations performed.

The power factor analysis determined the amount of reactive support required to maintain the scheduled voltages at the Potter 345 kV point of interconnection.

The Group 5 project does not have an adverse impact on the stability of the SPP system, for the contingencies and system conditions tested.

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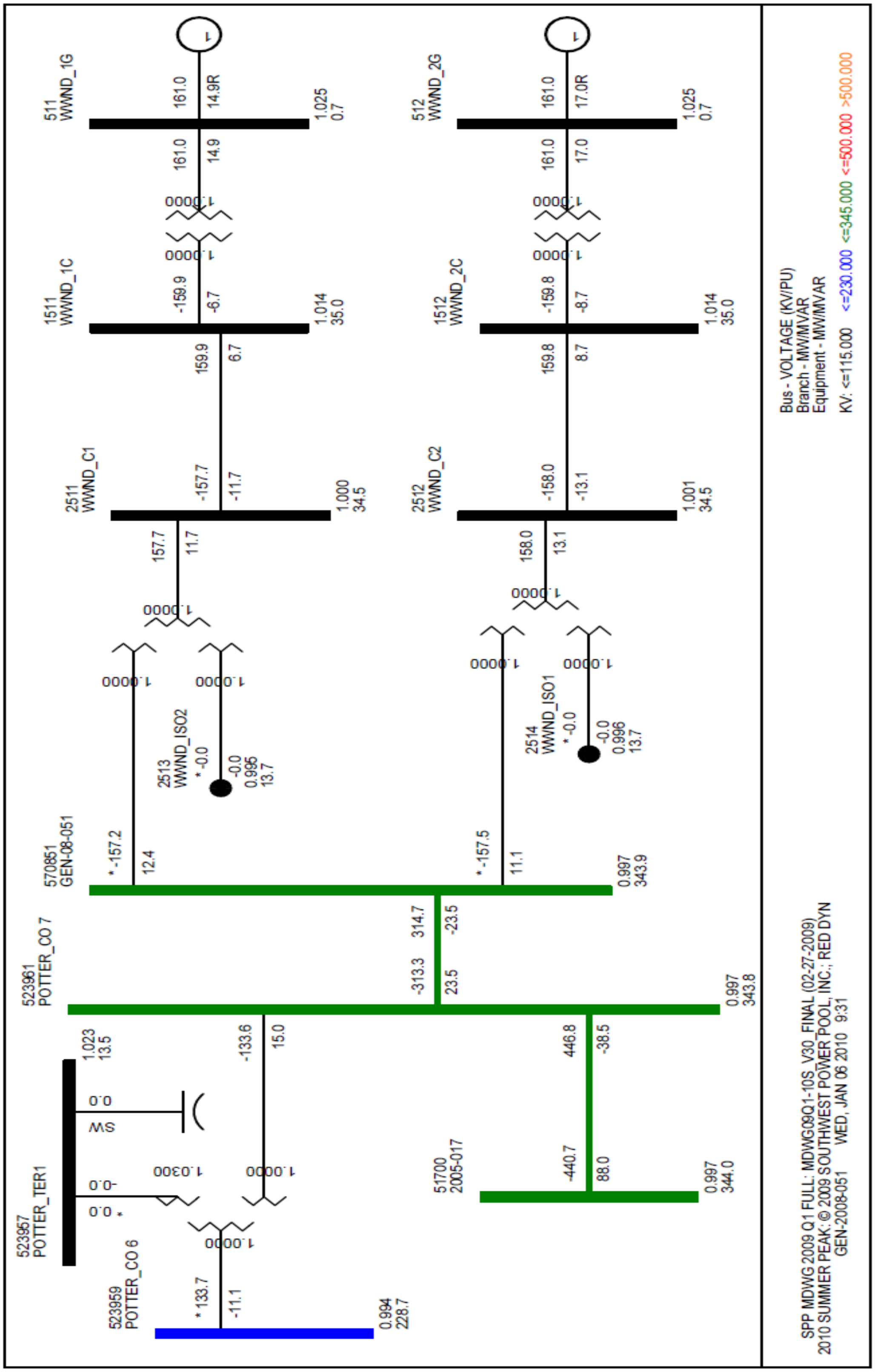
Appendix

A

WTG Single Line Diagrams

This appendix contains the single line diagram, showing the modeling details of the Group 5 project.

A.1 GEN-2008-051



Appendix

B

WTG Dynamic Models Documentation

This appendix shows the model data used to represent the turbines in the simulations.

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Appendix

C

Steady State Results

This Appendix shows the voltage analysis results. The voltages at each POI were monitored for any deviations from the base case voltage and the percentage voltage deviations were documented.

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Appendix

D

Stability Results

The plots of the evaluated contingencies are shown in this appendix. There are 4 plots for each contingency, which include the following channels:

- Bus Voltages.
- Speed Deviation.
- Active and Reactive Power Injection at the POI
- Electric Power of the Proposed WTGs

D.1 Summer Peak Stability Results

D.2 Winter Peak Stability Results

N: Stability Study for Group 6

O: Stability Study for Group 7

SPP DISIS-2009-001 Group 7 Definitive Impact Study

Draft Report for

Southwest Power Pool

Prepared by:
Excel Engineering, Inc.

January 19, 2010

Principal Contributor:

William Quaintance, P.E.

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0. Certification

I hereby certify that this plan, specification, or report was prepared by me or under my direct supervision and that I am a duly Licensed Professional Engineer under the Laws of the State of **Arkansas**.

William Quaintance
Arkansas Registration Number 13865

1. Background and Scope

The DISIS-2009-001 Group #7 Definitive Impact Study is a generation interconnection study performed by Excel Engineering, Inc. for its non-affiliated client, Southwest Power Pool (SPP). Its purpose is to study the impacts of interconnecting the two projects shown in Table 1-1. The in-service date assumed for the generation additions was 2010.

Table 1-1. Interconnection Requests to be Evaluated

Request	Size	Wind Turbine Model	Point of Interconnection
GEN-2008-023	150	G.E. 1.5MW	Hobart Junction 138kV (511463)
GEN-2009-016	140	Siemens 2.3MW	Falcon Road 138KV (511511)

The previously-queued requests shown in Table 1-2 were included in this study and dispatched at 100% of rated capacity.

Table 1-2. Nearby Interconnection Requests Already in the Queue

Request	Size	Wind Turbine Model	Point of Interconnection
Blue Canyon I	74	CIMTR	Washita 138kV (521089)
Blue Canyon II (GEN-2003-004)	151	Vestas V80	Washita 138kV (521089)
Weatherford	147	G.E. 1.5MW	Weatherford 138kV (511506)
GEN-2003-005	100	G.E. 1.5MW	Anadarko – Paradise 138kV (560916)
GEN-2006-002	150	Gamesa	Beckham County 230kV (560012)
GEN-2006-035	224	Gamesa	Beckham County 230kV (560012)
GEN-2006-043	99	G.E. 1.5MW	Beckham County 230kV (560012)
GEN-2007-032	150	Acciona 1.5MW	Clinton Jct. – Clinton 138kV (560939)
GEN-2007-043	300	G.E. 1.5MW	Cimarron – Anadarko 345kV (210431)
GEN-2007-052	150	Gas Turbine	Anadarko 138kV (520814)

The study included stability analysis of each proposed interconnection request. Contingencies that resulted in a prior-queued project tripping off-line, if any, were re-run with the prior-queued project's voltage and frequency tripping disabled. Since both of the interconnection requests in this group are wind projects, a power factor analysis was performed.

ATC (Available Transfer Capability) studies were not performed as part of this study. These studies will be required at the time transmission service is actually requested. Additional transmission upgrades may be required based on that analysis.

Study assumptions in general have been based on Excel's knowledge of the electric power system and on the specific information and data provided by SPP. The accuracy of the conclusions contained within this study is sensitive to the assumptions made with respect to generation additions and transmission improvements being contemplated. Changes in the assumptions of the timing of other generation additions or transmission improvements will affect this study's conclusions.

2. Executive Summary

The DISIS-2009-001 Group #7 Definitive Impact Study evaluated the impacts of interconnecting projects GEN-2008-023 and GEN-2009-016 to the SPP transmission system.

One stability problem was found in the summer and winter peak cases after the addition of these generators. The GEN-2009-016 plant is unstable following Fault 21, a three-phase fault on the Falcon Rd to Elk City 138 kV line. The solution is for GEN-2009-016 to add a high-speed, continuously-controlled reactive power compensation device, such as an SVC or STATCOM, with a capacity of at least 6 Mvar. To provide some margin, a minimum 10 Mvar size is recommended. This reactive power device should be operated such that its dynamic capacitive capability is always available to respond to system events.

Power factor requirements were determined, and all study plants must install sufficient reactive power resources to meet the requirements listed in Table 4-2. Except as mentioned above, the reactive power resources need not be high-speed or continuously-controlled. However, any change in wind turbine model or controls could change the stability results, possibly resulting in a need for larger or additional high-speed, continuously-controlled reactive power compensation.

With the assumptions and upgrades described in this report, DISIS-2009-001 Group 7 should be able to connect without causing any stability problems on the SPP transmission grid.

3. Study Development and Assumptions

3.1 Simulation Tools

The Siemens Power Technologies, Inc. PSS/E power system simulation program Version 30.3.3 was used in this study.

3.2 Models Used

SPP provided its latest stability database cases for both summer and winter peak seasons. Each plant's PSS/E model had been developed prior to this study and was included in the power flow case and the dynamics database. As a result, no additional generator modeling was required. Power flow one-line diagrams of the study projects are shown in Figure 3-1 and Figure 3-2. As the figures show, each wind farm model includes explicit representation of the radial transmission line, if any; the substation transformer(s) from transmission voltage to 34.5 kV; and the substation reactive power device(s), if any. The remainder of each wind farm is represented by one or more lumped equivalents including a generator, a step-up transformer, and a collector system impedance. Steady-state and dynamic model data for the study plants are given in Appendix D.

No special modeling is required of line relays in these cases, except for the special modeling related to the wind-turbine tripping.

3.3 Monitored Facilities

All generators and transmission buses in Areas 520, 524, 525, 526, 531, 534, and 536 were monitored.

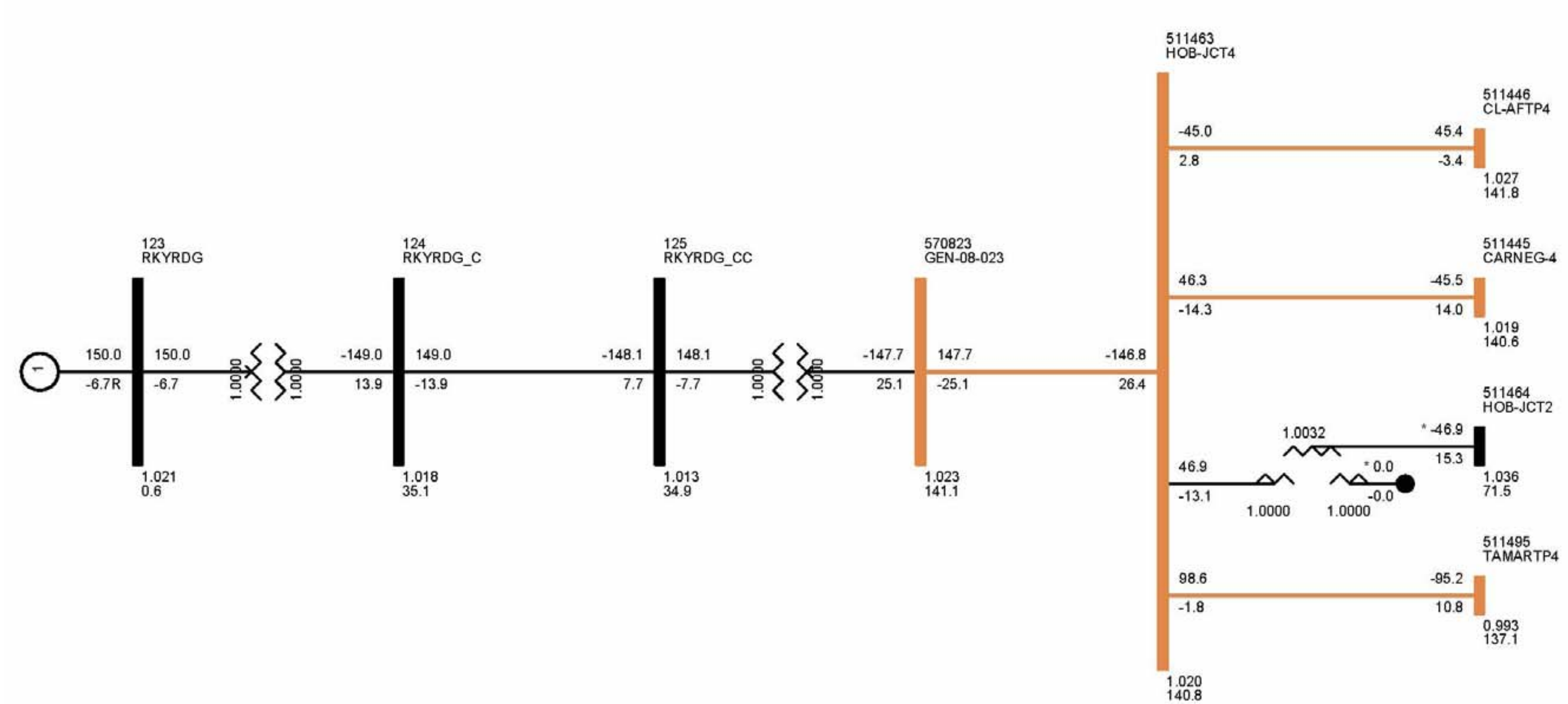

Figure 3-1. Power Flow One-line for GEN-2008-023

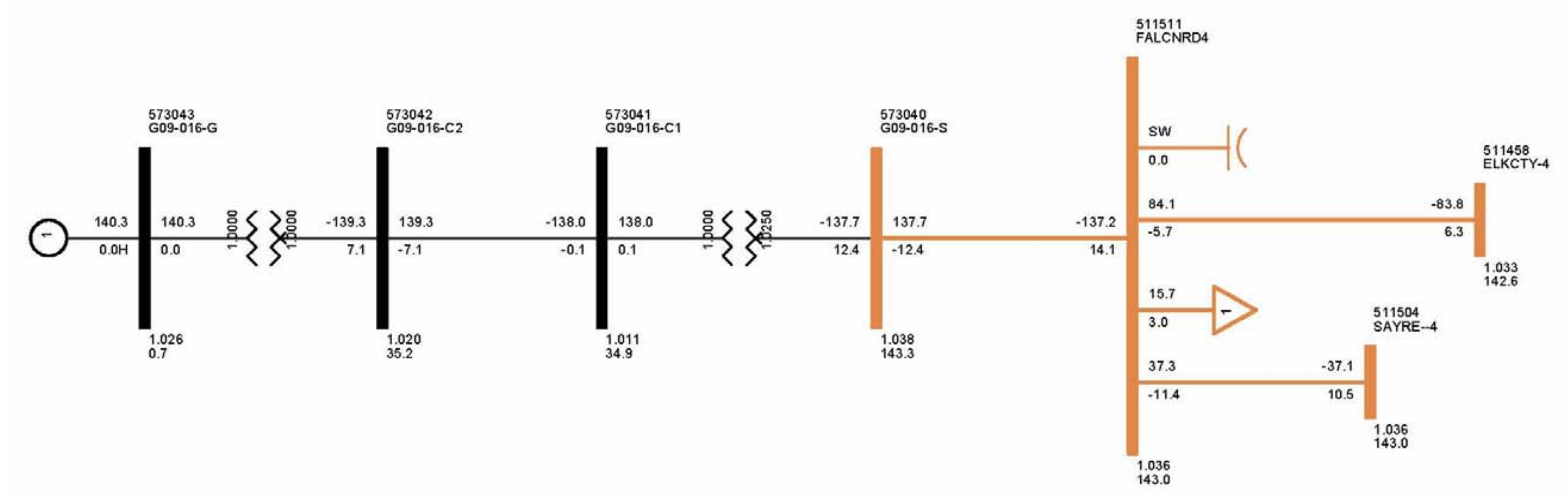

Figure 3-2. Power Flow One-line for GEN-2009-016

3.4 Performance Criteria

The wind generators must comply with FERC Order 661A on low voltage ride through for wind farms. Therefore, the wind generators should not trip off line for faults for under voltage relay actuation. If a wind generator trips off line, an appropriately sized SVC or STATCOM device may need to be specified to keep the wind generator on-line for the fault. SPP was consulted to determine if the addition of an SVC or STATCOM is warranted for the specific condition.

Contingencies that resulted in a prior-queued project tripping off-line, if any, were re-run with the prior-queued project's voltage and frequency tripping disabled to check for stability issues.

3.5 Performance Evaluation Methods

Since all of the interconnection requests are wind projects, a power factor analysis was performed. The power factor analysis consisted of modeling a var generator in each wind farm holding a voltage schedule at the POI. The voltage schedule was set equal to the higher of the voltage with the wind farm off-line or 1.0 per unit.

If the required power factor at the POI is beyond the capability of the studied wind turbines, then capacitor banks would be considered. Factors used in sizing capacitor banks would include two requirements of FERC Order 661A: the ability of the wind farm to ride through low voltage with and without capacitor banks and the ability of the wind farm to recover to pre-fault voltage. If a wind generator trips on high voltage, a leading power factor may be required.

ATC studies were not performed as part of this study. These studies will be required at the time transmission service is actually requested. Additional transmission facilities may be required based on subsequent ATC analysis.

Stability analysis was performed for each proposed interconnection request. Faults were simulated on transmission lines at the POIs and on other nearby transmission equipment. The faults in Table 3-1 were run for each case (three phase and single phase as noted).

Table 3-1. Fault Definitions for DISIS-2009-001 Group 7

Cont. No.	Contingency Name	Description
1	FLT01-3PH	3 phase fault on the GEN-2007-043 (210431) to Anadarko (511541) 345kV line, near GEN-2007-043. a. Apply fault at the GEN-2007-043 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*

Cont. No.	Contingency Name	Description
3	FLT03-3PH	3 phase fault on the Anadarko (511541) to Wheeler/Midpoint (525835) 345kV line, near Anadarko. a. Apply fault at the Anadarko 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 Lawton Eastside (511468) to Sunnyside (515136) 345kV line, near Lawton Eastside. a. Apply fault at the Lawton Eastside 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 GEN-2007-032 (560939) to Clinton Jct. (511485) 138kV line, near GEN-2007-032. a. Apply fault at the GEN-2007-032 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.
8	FLT08-1PH	*Single phase fault and sequence like previous*
9	FLT09-3PH	3 phase fault on the Clinton Jct. (511485) to Elk City (511458) 138kV line, near Clinton Jct. a. Apply fault at the Clinton Jct. 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.
10	FLT10-1PH	*Single phase fault and sequence like previous*
11	FLT11-3PH	3 phase fault on the Weatherford Wind (511506) to Weatherford Tap (511536) 138kV line, near Weatherford Wind. a. Apply fault at the Weatherford Wind 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.
12	FLT12-1PH	*Single phase fault and sequence like previous*
13	FLT13-3PH	3 phase fault on the Elk City (511458) to Red Hill (521116) 138kV line, near Elk City. a. Apply fault at the Elk City 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.
14	FLT14-1PH	*Single phase fault and sequence like previous*
15	FLT15-3PH	3 phase fault on the Elk City (511458) to Clinton AF (511446) 138kV line, near Elk City. a. Apply fault at the Elk City 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.
16	FLT16-1PH	*Single phase fault and sequence like previous*

Cont. No.	Contingency Name	Description
17	FLT17-3PH	3 phase fault on the Elk City 138kV (511458) to 230kV (511490) transformer, near the 138kV bus. a. Apply fault at the Elk City 138kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
18	FLT18-1PH	*Single phase fault and sequence like previous*
19	FLT19-3PH	3 phase fault on the Anadarko 138kV (520814) to 345kV (511541) transformer, near the 138kV bus. a. Apply fault at the Anadarko 138kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
20	FLT20-1PH	*Single phase fault and sequence like previous*
21	FLT21-3PH	3 phase fault on the Falcon Road (511511) to Elk City (511458) 138kV line, near the Falcon Road bus. a. Apply fault at the Falcon Road 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 Falcon Road (511511) to Sayre (511504) 138kV line, near Falcon Road. a. Apply fault at the Falcon Road 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 Hobart Jct (511463) to Clinton AFB (511446) 138kV line, near Hobart Jct. a. Apply fault at Hobart Jct. 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 Hobart Jct (511463) to Carnegie South (511445) 138kV line, near Hobart Jct. a. Apply fault at Hobart Jct. 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 Hobart Jct. (511463) to Tamarack Tap (511495) 138kV line, near Hobart Jct. a. Apply fault at Hobart Jct. 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 Hobart Jct. (511463) 138/69kv auto. a. Apply fault at Hobart Jct. b. Clear fault after 5 cycles by tripping the faulted auto.
32	FLT32-1PH	*Single phase fault and sequence like previous*

Cont. No.	Contingency Name	Description
33	FLT33-3PH	3 phase fault on the Elk City (511490) to Beckham (560012) 230kV line, near Elk City. a. Apply fault at Elk City 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.
34	FLT34-1PH	*Single phase fault and sequence like previous*
35	FLT35-3PH	3 phase fault on the Altus (511440) to Snyder (511435) 138kV line, near Altus. a. Apply fault at Altus 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.
36	FLT36-1PH	*Single phase fault and sequence like previous*
37	FLT37-3PH	3 phase fault on the Morewood (521001) to Mooreland (520999) 138kV line, near Morewood. a. Apply fault at Morewood 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.
38	FLT38-1PH	*Single phase fault and sequence like previous*
39	FLT39-3PH	3 phase fault on the Anadarko (520814) to Southwest (511477) 138kV line, near Anadarko. a. Apply fault at the Anadarko 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.
40	FLT40-1PH	*Single phase fault and sequence like previous*
41	FLT41-3PH	3 phase fault on the Southwest (511477) to Verden (511421) 138kV line, near Southwest. a. Apply fault at the Southwest 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.
42	FLT42-1PH	*Single phase fault and sequence like previous*
43	FLT43-3PH	3 phase fault on the Southwest (511477) to Elgin Jct. (511486) 138kV line, near Southwest. a. Apply fault at the Southwest 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.
44	FLT44-1PH	*Single phase fault and sequence like previous*
45	FLT45-3PH	3 phase fault on the Anadarko (520814) to Cornville Tap (520867) 138kV line, near Anadarko. a. Apply fault at the Anadarko 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.
46	FLT46-1PH	*Single phase fault and sequence like previous*

4. Results and Observations

4.1 Stability Analysis Results

All faults were run for both summer and winter peak conditions. If a previously-queued generator tripped for any of these faults, the voltage and frequency tripping was disabled, and the fault was re-run to check for system stability. No tripping occurred in this study.

Table 4-1 summarizes the overall results for all faults. Figure 4-1 through Figure 4-4 show representative summer peak season plots for a fault at the POI of each of the study projects. Complete sets of plots for both summer and winter peak seasons for each fault and each project are included in Appendices A and B.

As shown in Figure 4-3 and Figure 4-4, GEN-2009-016 and its POI voltage are unstable following Fault 21, a three-phase fault on the Falcon Rd to Elk City 138 kV line. This instability is found in both the summer and winter peak cases. Following outage of this line, the only remaining connection to the grid for GEN-2009-016 is a long 138 kV line to Sayre, Erick, Sweetwater, Durham, Brantley, and Morewood. The Siemens wind turbines are unable to remain stable under these conditions.

This contingency was tested with steady-state QV analysis and was found to be unstable due to insufficient reactive power support. A mechanically switched capacitor does not fix the problem. Only a continuously controlled voltage support device of at least 6 Mvar (in the winter case) will maintain steady-state stability.

A STATCOM was modeled on the GEN-2009-016 34.5 kV substation bus, and dynamic simulations show that the minimum STATCOM size needed for stability of Fault 21 is 6 Mvar in the winter peak case and 1 Mvar in the summer case. A larger STATCOM size such as 10 Mvar is recommended to provide some margin for variation in plant and system conditions.

Table 4-1. Summary of Results

Cont. No.	Contingency Name	Description	Summer Peak Results	Winter Peak Results
1	FLT01-3PH	3 phase fault on the GEN-2007-043 (210431) to Anadarko (511541) 345kV line, near GEN-2007-043.	OK	OK
2	FLT02-1PH	*Single phase fault and sequence like previous*	OK	OK
3	FLT03-3PH	3 phase fault on the Anadarko (511541) to Wheeler/Midpoint (525835) 345kV line, near Anadarko.	OK	OK
4	FLT04-1PH	*Single phase fault and sequence like previous*	OK	OK
5	FLT05-3PH	3 phase fault on the Lawton Eastside (511468) to Sunnyside (515136) 345kV line, near Lawton Eastside.	OK	OK
6	FLT06-1PH	*Single phase fault and sequence like previous*	OK	OK

Cont. No.	Contingency Name	Description	Summer Peak Results	Winter Peak Results
7	FLT07-3PH	3 phase fault on the GEN-2007-032 (560939) to Clinton Jct. (511485) 138kV line, near GEN-2007-032.	OK	OK
8	FLT08-1PH	*Single phase fault and sequence like previous*	OK	OK
9	FLT09-3PH	3 phase fault on the Clinton Jct. (511485) to Elk City (511458) 138kV line, near Clinton Jct.	OK	OK
10	FLT10-1PH	*Single phase fault and sequence like previous*	OK	OK
11	FLT11-3PH	3 phase fault on the Weatherford Wind (511506) to Weatherford Tap (511536) 138kV line, near Weatherford Wind.	OK	OK
12	FLT12-1PH	*Single phase fault and sequence like previous*	OK	OK
13	FLT13-3PH	3 phase fault on the Elk City (511458) to Red Hill (521116) 138kV line, near Elk City.	OK	OK
14	FLT14-1PH	*Single phase fault and sequence like previous*	OK	OK
15	FLT15-3PH	3 phase fault on the Elk City (511458) to Clinton AF (511446) 138kV line, near Elk City.	OK	OK
16	FLT16-1PH	*Single phase fault and sequence like previous*	OK	OK
17	FLT17-3PH	3 phase fault on the Elk City 138kV (511458) to 230kV (511490) transformer, near the 138kV bus.	OK	OK
18	FLT18-1PH	*Single phase fault and sequence like previous*	OK	OK
19	FLT19-3PH	3 phase fault on the Anadarko 138kV (520814) to 345kV (511541) transformer, near the 138kV bus.	OK	OK
20	FLT20-1PH	*Single phase fault and sequence like previous*	OK	OK
21	FLT21-3PH	3 phase fault on the Falcon Road (511511) to Elk City (511458) 138kV line, near the Falcon Road bus.	G09-16 and nearby voltages Unstable	
21fix1	FLT21-3PH-fix1	3 phase fault on the Falcon Road (511511) to Elk City (511458) 138kV line, near the Falcon Road bus. ***6 Mvar STATCOM at G09-16 34.5 kV substation bus.***	OK	OK
22	FLT22-1PH	*Single phase fault and sequence like previous*	OK	OK
23	FLT23-3PH	3 phase fault on the Falcon Road (511511) to Sayre (511504) 138kV line, near Falcon Road.	OK	OK
24	FLT24-1PH	*Single phase fault and sequence like previous*	OK	OK
25	FLT25-3PH	3 phase fault on the Hobart Jct (511463) to Clinton AFB (511446) 138kV line, near Hobart Jct.	OK	OK
26	FLT26-1PH	*Single phase fault and sequence like previous*	OK	OK
27	FLT27-3PH	3 phase fault on the Hobart Jct (511463) to Carnegie South (511445) 138kV line, near Hobart Jct.	OK	OK
28	FLT28-1PH	*Single phase fault and sequence like previous*	OK	OK
29	FLT29-3PH	3 phase fault on the Hobart Jct. (511463) to Tamarack Tap (511495) 138kV line, near Hobart Jct.	OK	OK
30	FLT30-1PH	*Single phase fault and sequence like previous*	OK	OK
31	FLT31-3PH	3 phase fault on the Hobart Jct. (511463) 138/69kv auto.	OK	OK
32	FLT32-1PH	*Single phase fault and sequence like previous*	OK	OK
33	FLT33-3PH	3 phase fault on the Elk City (511490) to Beckham (560012) 230kV line, near Elk City.	OK	OK

Cont. No.	Contingency Name	Description	Summer Peak Results	Winter Peak Results
34	FLT34-1PH	*Single phase fault and sequence like previous*	OK	OK
35	FLT35-3PH	3 phase fault on the Altus (511440) to Snyder (511435) 138kV line, near Altus.	OK	OK
36	FLT36-1PH	*Single phase fault and sequence like previous*	OK	OK
37	FLT37-3PH	3 phase fault on the Morewood (521001) to Mooreland (520999) 138kV line, near Morewood.	OK	OK
38	FLT38-1PH	*Single phase fault and sequence like previous*	OK	OK
39	FLT39-3PH	3 phase fault on the Anadarko (520814) to Southwest (511477) 138kV line, near Anadarko.	OK	OK
40	FLT40-1PH	*Single phase fault and sequence like previous*	OK	OK
41	FLT41-3PH	3 phase fault on the Southwest (511477) to Verden (511421) 138kV line, near Southwest.	OK	OK
42	FLT42-1PH	*Single phase fault and sequence like previous*	OK	OK
43	FLT43-3PH	3 phase fault on the Southwest (511477) to Elgin Jct. (511486) 138kV line, near Southwest.	OK	OK
44	FLT44-1PH	*Single phase fault and sequence like previous*	OK	OK
45	FLT45-3PH	3 phase fault on the Anadarko (520814) to Cornville Tap (520867) 138kV line, near Anadarko.	OK	OK
46	FLT46-1PH	*Single phase fault and sequence like previous*	OK	OK

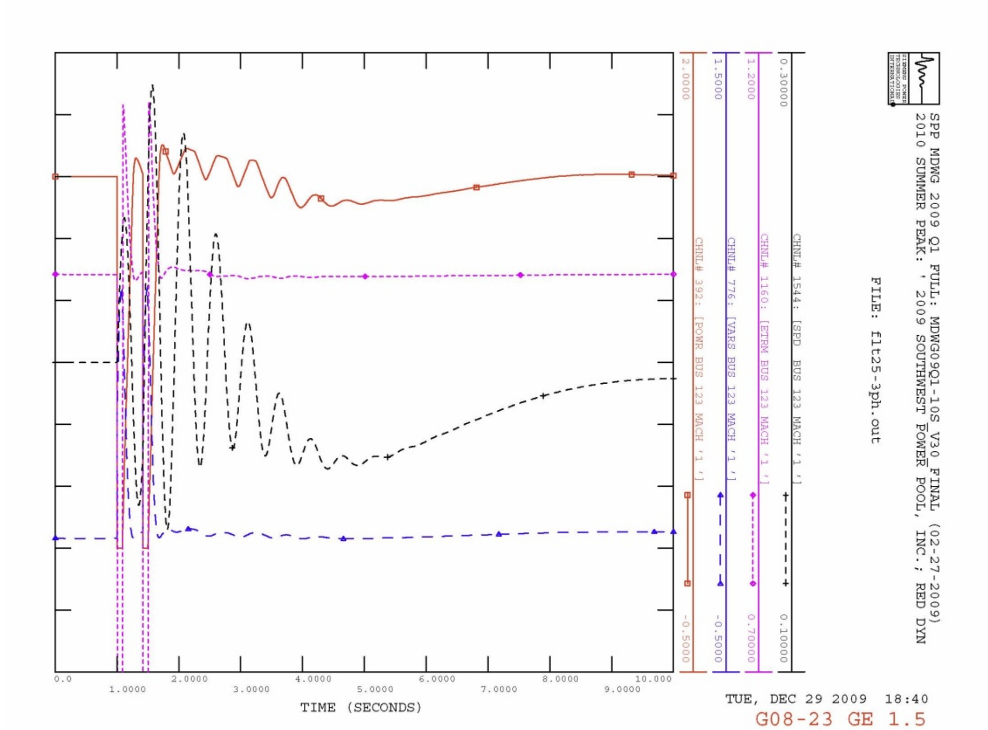

Figure 4-1. GEN-2008-023 Plot for Fault 25 – 3-Phase Fault on the Hobart Jct to Clinton AFB 138 kV line, near Hobart Jct

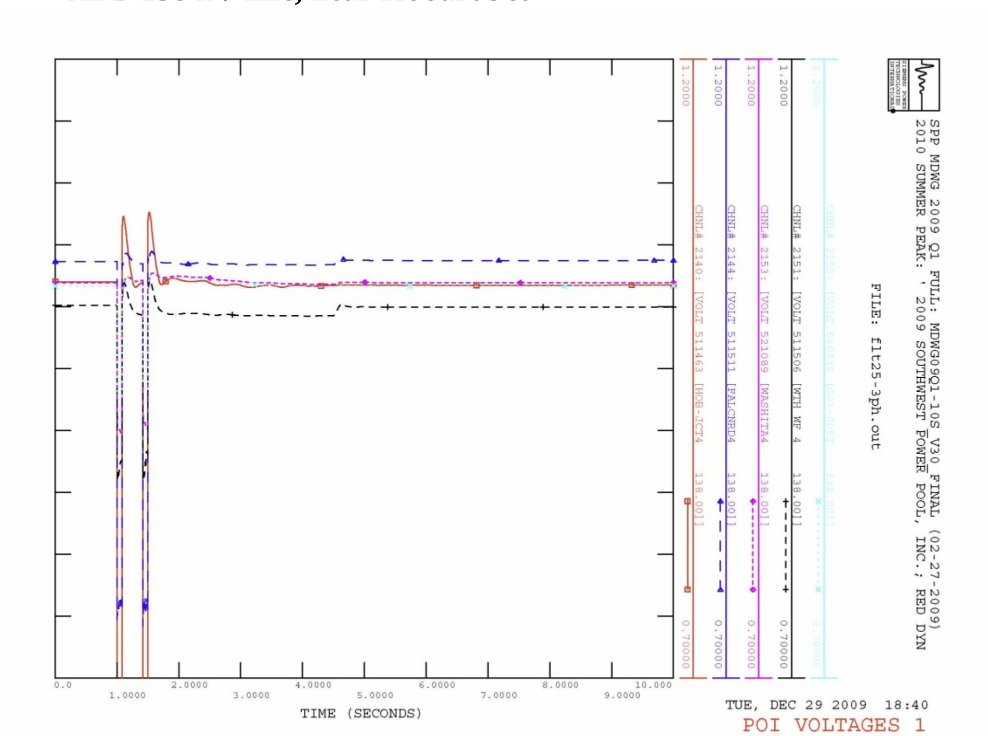

Figure 4-2. POI Voltages Plot for Fault 25 – 3-Phase Fault on the Hobart Jct to Clinton AFB 138 kV line, near Hobart Jct

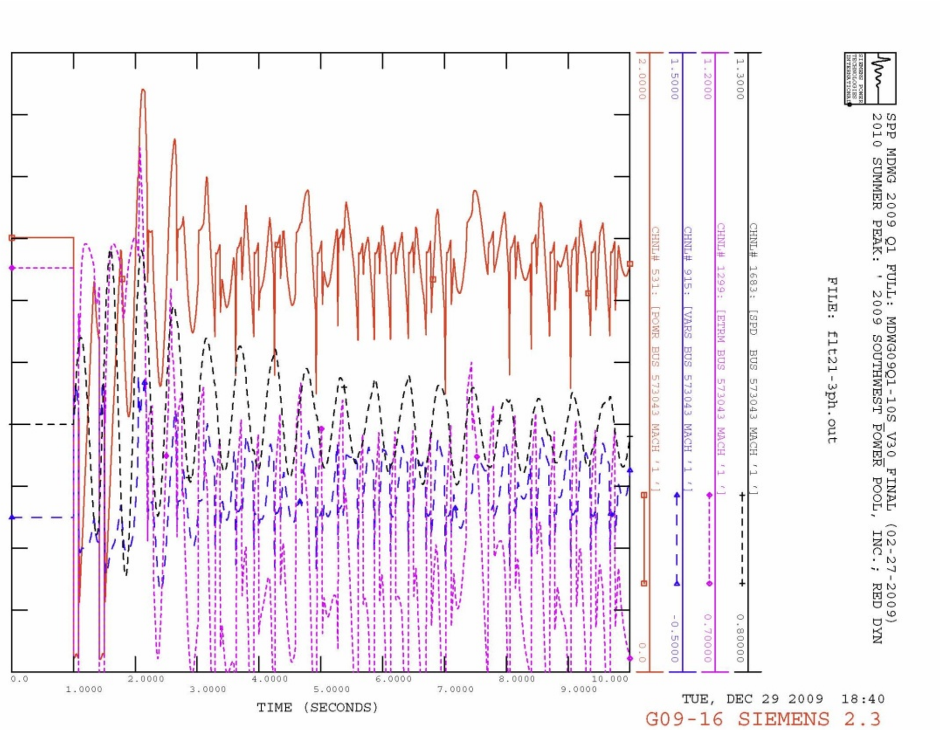

Figure 4-3. GEN-2009-016 Plot for Fault 21 – 3-Phase Fault on the Falcon Rd to Elk City 138 kV line, near Falcon Rd

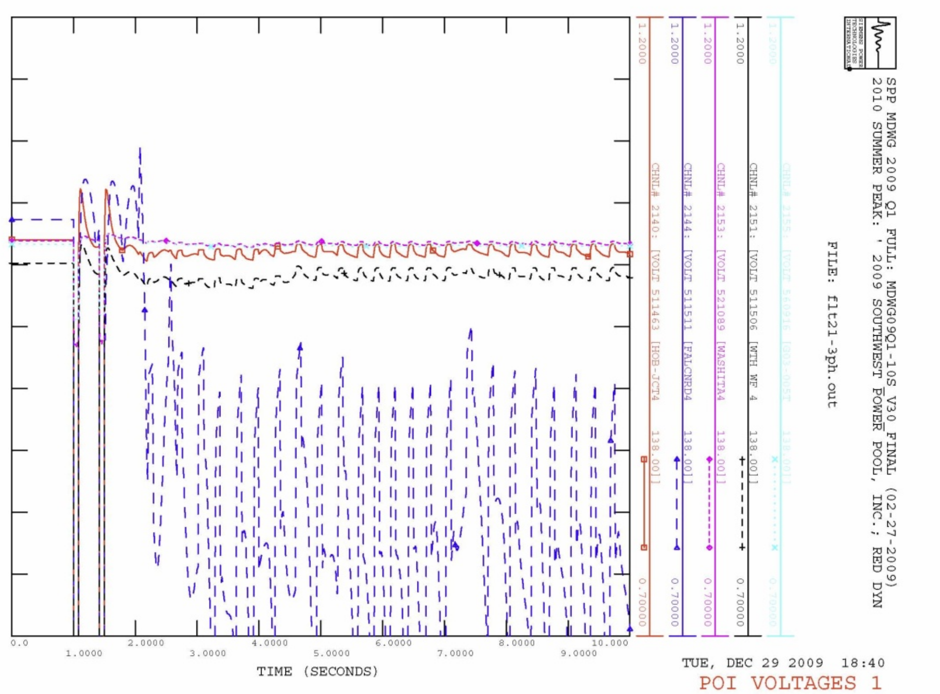

Figure 4-4. POI Voltages Plot for Fault 21 – 3-Phase Fault on the Falcon Rd to Elk City 138 kV line, near Falcon Rd

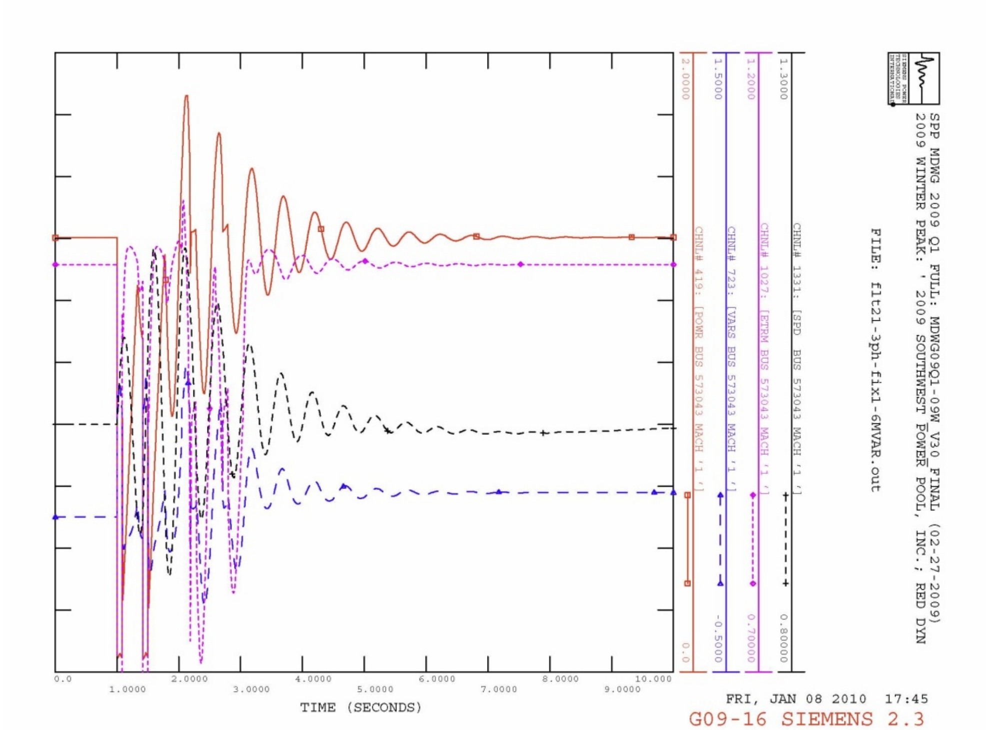

Figure 4-5. GEN-2009-016 Plot for Fault 21 – with a 6 Mvar STATCOM added to GEN-2009-016

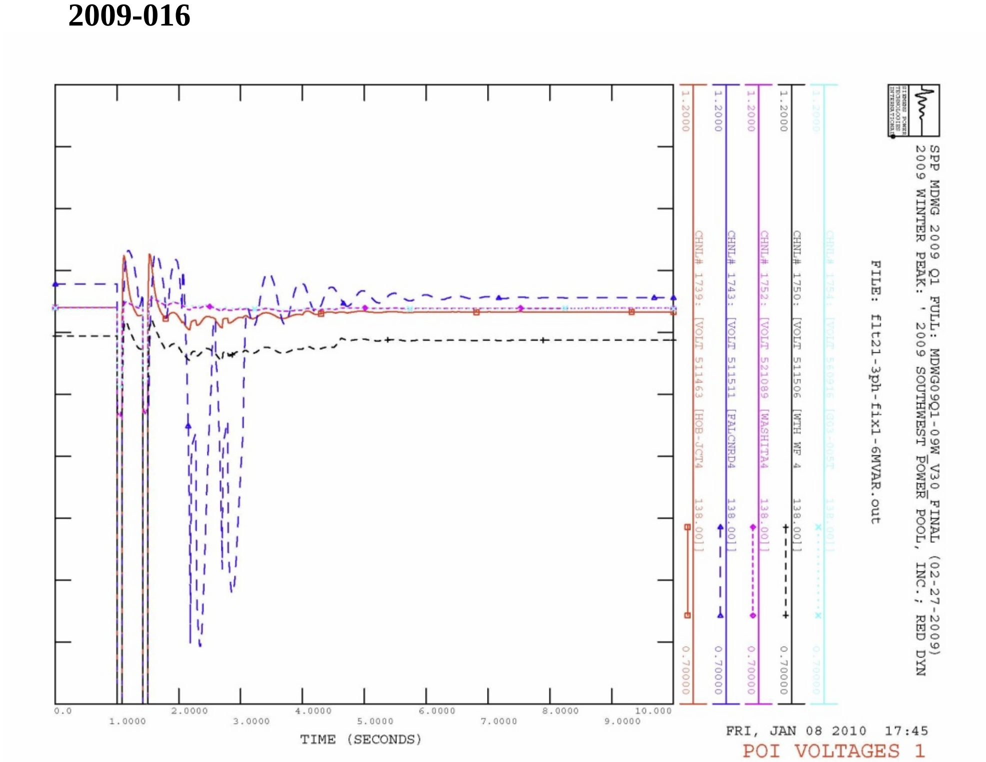

Figure 4-6. POI Voltages Plot for Fault 21 – with a 6 Mvar STATCOM added to GEN-2009-016

4.2 Generator Performance

The Vestas V80 wind turbines at Blue Canyon II show extended oscillations in their generator speeds, as shown in Figure 4-7. However, any impact on the electric system is gone in less than 10 seconds.

Prior-queued project GEN-2007-052 has synchronous generators for its three gas turbines. While stable, the gas turbine excitation system responds rather slowly after fault clearing (Figure 4-8). The terminal voltage overshoots to more than 105% and takes approximately 3-4 seconds to come back to steady state. The project developer should provide updated and accurate dynamic model parameters when these units are commissioned.

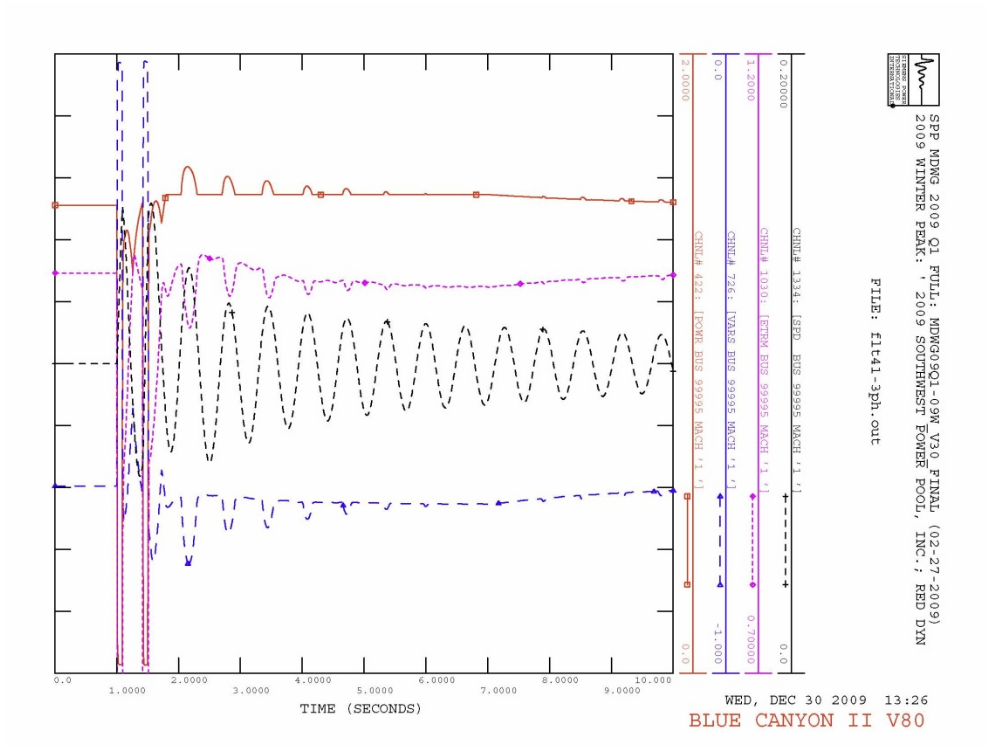

Figure 4-7. Blue Canyon II Plot for Fault 41 – 3 phase fault on the Southwest to Verden 138kV line

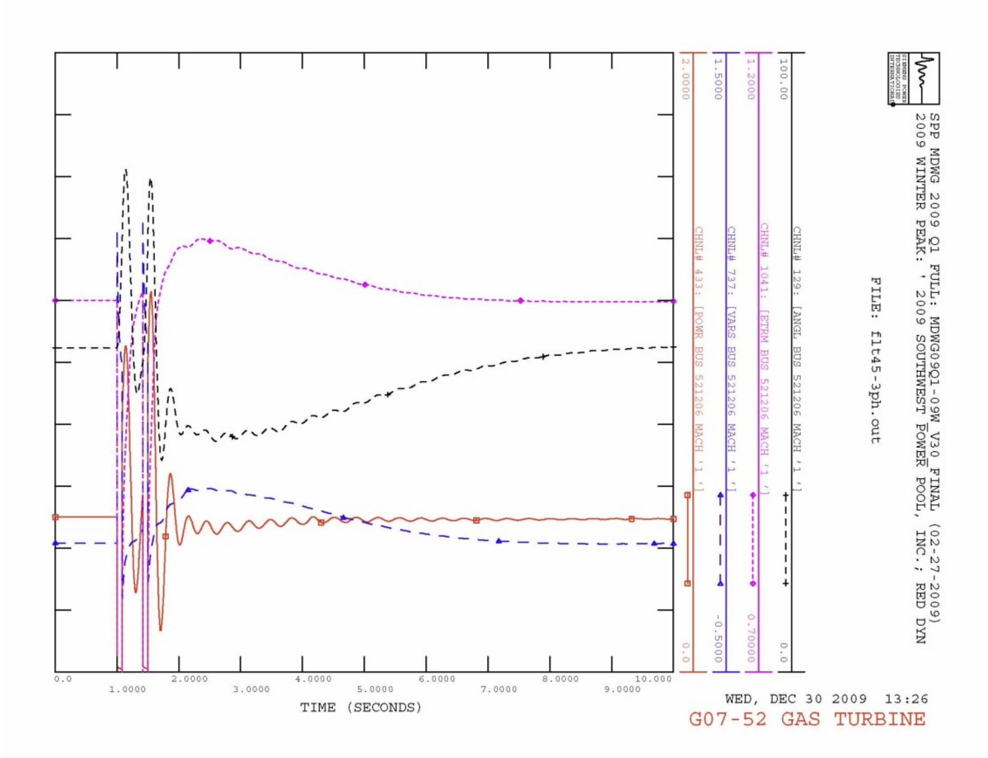

Figure 4-8. GEN-2007-052 Plot for Fault 45 – 3-Phase Fault on the Anadarko to Cornville Tap 138kV line

4.3 Power Factor Requirements

All stability faults were tested as power flow contingencies to determine the power factor requirements for the wind farm study projects to maintain scheduled voltage at their respective points of interconnection (POI). The voltage schedules are set equal to the voltages at the POIs before the projects are added, with a minimum of 1.0 per unit. Fictitious reactive power sources were added to the study projects to maintain scheduled voltage during all studied contingencies. The MW and Mvar injections from the study projects at the POIs were recorded and the resulting power factors were calculated for all contingencies for summer peak and winter peak cases. The most leading and most lagging power factors determine the minimum power factor range capability that the study projects must install before commercial operation.

If more than one study project shared a single POI (none in this case), the projects were grouped together and a common power factor requirement was determined for those study projects. This ensures that none of the study projects is required to provide more or less than its fair share of the reactive power requirements at a single POI. *Prior-queued* projects at the same POI, if any, were not grouped with the study projects because their interconnection requirements were determined in previous studies.

Per FERC and SPP Tariff requirements, if the power factor needed to maintain scheduled voltage were less than 0.95 lagging, then the requirement would be set to 0.95 lagging. This limit was not reached for any study project. The limit for leading power factor requirement is also 0.95, and GEN-2008-023 went beyond this level. Only 0.95 leading will be required.

The final power factor requirements are shown in Table 4-2 below. These are only the minimum power factor ranges based on steady-state analysis. A project developer may install more capability than this if desired.

The full details for each contingency in summer and winter peak cases are given in Appendix C.

Table 4-2. Power Factor Requirements [1]

Project	MW	Turbine	POI	Final PF Requirement	
				Lagging [2]	Leading [3]
GEN-2008-023	150	G.E. 1.5MW	Hobart Junction 138kV	1.0	0.95
GEN-2009-016	140	Siemens 2.3MW	Falcon Road 138KV	1.0	0.965

Notes:
1. For each plant, the table shows the minimum required power factor capability at the point of interconnection that must be designed and installed with the plant. The power factor capability at the POI includes the net effect of the generators, transformers, line impedances, and any reactive compensation devices installed on the plant side of the meter. Installing more capability than the minimum requirement is acceptable.
2. Lagging is when the generating plant is supplying reactive power to the transmission grid. In this situation, the alternating current sinusoid "lags" behind the alternating voltage sinusoid, meaning that the current peaks shortly after the voltage.
3. Leading is when the generating plant is taking reactive power from the transmission grid. In this situation, the alternating current sinusoid "leads" the alternating voltage sinusoid, meaning that the current peaks shortly before the voltage.

5. Conclusions

The DISIS-2009-001 Group 7 Definitive Impact Study evaluated the impacts of interconnecting each of the projects shown below.

Table 5-1. Interconnection Requests Evaluated in this Study

Request	Size	Wind Turbine Model	Point of Interconnection
GEN-2008-023	150	G.E. 1.5MW	Hobart Junction 138kV (511463)
GEN-2009-016	140	Siemens 2.3MW	Falcon Road 138KV (511511)

One stability problem was found in the summer and winter peak cases after the addition of these generators. GEN-2009-016 is unstable following Fault 21, a three-phase fault on the Falcon Rd to Elk City 138 kV line. The solution is for GEN-2009-016 to add a high-speed, continuously-controlled reactive power compensation device, such as an SVC or STATCOM, with a capacity of at least 6 Mvar. To provide some margin, a minimum 10 Mvar size is recommended. This reactive power device should be operated such that its dynamic capacitive capability is always available to respond to system events.

Power factor requirements were determined, and all study plants must install sufficient reactive power resources to meet the requirements listed in Table 4-2. Except as mentioned above, the reactive power resources need not be high-speed and continuously-controlled. However, any change in wind turbine model or controls could change the stability results, possibly resulting in a need for larger or additional high-speed, continuously-controlled reactive power compensation.

With the assumptions and upgrades described in this report, DISIS-2009-001 Group 7 should be able to connect without causing any stability problems on the SPP transmission grid.

Appendix A – Summer Peak Plots

See attachment.

Appendix B – Winter Peak Plots

See attachment.

Appendix C – Power Factor Details

See attachment.

Appendix D – Project Model Data

See attachment.