Southwest Power Pool

GEN-2009-016
Impact Restudy

SPP Generation
Interconnection Studies

GEN-2009-016

May 2011

Executive Summary

This report contains the findings of a restudy of GEN-2009-016. The GEN-2009-016 interconnection request was studied as part of the DISIS-2009-001 Definitive Impact Study, Cluster Group #7, which was originally posted in January 2010. A subsequent restudy was posted 2/5/2010. The original report showed that GEN-2009-016 will require a +/- 10 Mvar Static Var Compensator. With the power factor requirements, and all network upgrades in service, all interconnection request in Group 7 will meet FERC Order #661A low voltage ride through (LVRT) requirements and the transmission system will remain stable. The Final PF requirements for the Point Of Interconnection were 1.0 (Lagging) and 0.965 (Leading).

This restudy was performed solely to evaluate the effects of a turbine manufacturer change of switching wind turbine manufacturers from Siemens (2.3MW) for 140MW to GE (1.6MW) for 100.8MW. The requested In-Service Date is 12/01/2011. This study looked at interconnection at Falcon Road 138kV with and interconnection injection of 100.8MW.

The findings of the restudy show that for no stability problems were found during summer or winter peak conditions due to the addition of these generators. A Static Var Compensator is not required for the use of G.E. turbines and 100.8MW generating facility.

Power factor analysis was performed. The facility will be required to maintain a 95% lagging (providing vars) and 95% leading (absorbing vars) power factor a the point of interconnection.

With the assumptions outlined in this report, GEN-2009-016 should be able to reliably connect to the SPP transmission grid.

Nothing in this study should be construed as a guarantee of transmission service. If the customer wishes to sell power from the facility, a separate request for transmission service shall be requested on Southwest Power Pool’s OASIS by the Customer.

Pterra Consulting

Technical Report R114-11

GEN-2009-016
Impact Re-Study – Draft Report

Submitted to

Southwest Power Pool

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Executive Summary

This report presents the results of GEN-2009-016 (the "Project") impact re-study comprising of power factor and stability analyses. The Project has a nominal 100.8 MW maximum rating and this study was conducted using GE 1.6 MW wind turbine generators ("WTGs"). The Point of Interconnection ("POI") is the Falcon Road 138 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 its full output of 100.8 MW.

Two base cases, 2011 summer and winter peak conditions, each comprising of a power flow and corresponding dynamics database, were provided by SPP. The Project was modeled as one equivalent generator in the power flow model provided by SPP and was modeled in consultation with SPP.

Power Factor Test

The results of the power factor test analysis showed that with the MVAR capability of the GE 1.6 MW WTG and without reactive compensation, the power factor at the POI would be from 0.98 to 1.00 under summer peak conditions and 0.99 to 1.00 under winter peak conditions.

Stability Simulations

Forty-four (44) faults were considered for transient stability simulations which included 3-phase faults as well as 1-phase-to-ground faults at locations defined by SPP. The results of the simulations showed neither angular nor voltage instability problems for the forty-four faults. Although there are some oscilatory responses for Blue Canyon I and Blue Canyon II units, for some of the contingencies studied, these are related to a modeling issue regarding the Vestas dynamic models for these two units. The study then concludes that the interconnection of the proposed 100.8 MW Project does not impact the stability performance of the SPP system for the faults tested on the supplied base cases.

1.1. Project Overview

This report presents the results of the the proposed interconnection GEN-2009-016 (the "Project") impact re-study comprising of power factor and stability analyses. The Project has a nominal 100.8 MW maximum rating and was studied using GE 1.6 MW wind turbine generators ("WTGs"). The Point of Interconnection ("POI") is the Falcon Road 138 kV substation. Figure 1-1 shows the interconnection diagram of the Project to SPP's 138 kV system as modeled in the power flow base cases.

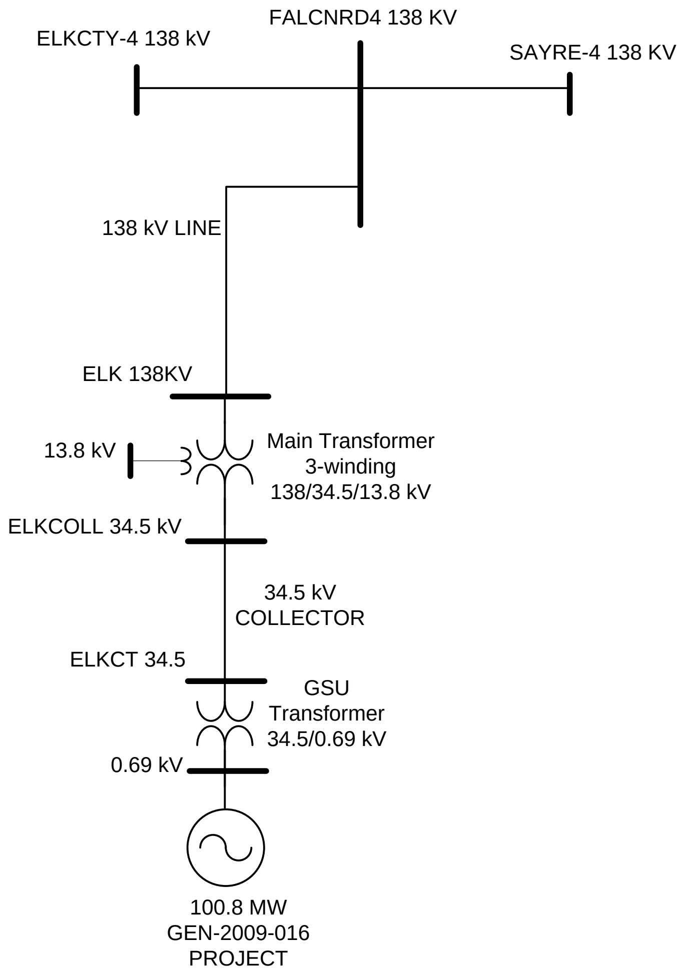

Figure 1-1 Power Flow Model for GEN-2009-016

Table 1-1 shows the list of previous queued projects modeled in the base cases.

Table 1-1 List of Prior Queued Projects

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
BLUE CAYON I	74	CIMTR	WASHITA 138kV (521089)
BLUE CANYON II (GEN-2003-004)	151	VESTAS V80	WASHITA 138kV (521089)
WEATHERFORD	147	G.E. 1.5 MW	WEATHERFORD 138kV (511506)
GEN-2003-005	100	G.E. 1.5 MW	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. 1.5 MW	BECKHAM COUNTY 230kV (560012)
GEN-2007-032	150	ACCIONA 1.5 MW	CLINTON JCT. – CLINTON 138kV (560939)
GEN-2007-043	300	G.E. 1.5 MW	CIMARRON – ANADARKO 345kV (210431)
GEN-2007-052	150	GAS TURBINE	ANADARKO 138kV (520814)
GEN-2008-023	150	G.E. 1.5 MW	HOBART JUNCTION (511463) 138kV
GEN-2010-012	65	CLIPPER 2.5 MW	BRANTLEY 138kV
GEN-2008-037	100.8	VESTAS V90 1.8 MW	WASHITA (521089)–BLUE CANYON (521103) 138kV (Bus 573570)
GEN-2009-030	100.8	G.E. 1.6 MW	WEATHERFORD 138kV (521092)
GEN-2009-060	85.5	G.E. 1.5 MW	GOTEBO 69kV (520925)
GEN-2010-040	300	SUZLON 2.1 MW	CIMARRON 345kV

1.2. Objectives

The objectives of the study are to conduct power factor analysis and to determine the impact on the system stability of interconnecting the proposed 100.8 MW wind farm project to SPP’s 138 kV 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. Turn off the Project wind farm as modeled (as well as previous queued projects at the same point of interconnection). Replace the wind farms by a generator at the high side bus with the MW of the wind farms and no VAR capability.

2. Model a VAR generator at the wind farm's substation high voltage 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 p.u. voltage, whichever is higher.

3. Conduct steady state contingency analysis to determine the power factor necessary at the POI for each contingency.

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

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

   5.1. The ability of the wind farm to meet FERC Order 661A (low voltage ride through) with and without capacitor banks.
   5.2. The ability of the wind farm to meet FERC Order 661A (wind farm recovery to pre-fault voltage).
   5.3. If wind farms trips on high voltage, power factor lower than unity may be required.

2.2. Analysis

The 100.8 MW Project was turned off in the provided power flow cases. A 100.8 MW generator equivalent to the capacity of the Project with no VAR capability was modeled at the Project's 138 kV bus. A VAR generator was also modeled at the same bus and was set to hold a voltage of 1.011 P.U. at the POI consistent with the voltage schedule in the provided power flow cases.

Contingency analysis was run for all the specified contingencies. Results show that the VAR generator absorbs reactive power in all the contingencies, except for contingencies Moorewood to Mooreland 138kV and Sweet Water to Wheeler 230 kV, where the VAR generator is providing VARS to the transmission system. The results are summarized in Table 2-1 below. The highest values obtained when the VAR generator is absorbing reactive power are 18.2 and 17.3 MVAR for the summer and winter cases, respectively, both due to the outage of Clinton Jct. to CL_NGTP 138 kV transmission line.

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

CASE	CONTINGENCY	POWER FACTOR		MW @ POI	VARGEN MVAR
SP	BASE CASE	0.99	Lag	100.8	-12.5
	Weatherford (521092) to Clinton (520856) 138kV line	1.00	Lag	100.8	-3
	Clinton Jct. (511485) to CL_NGTP (511534) 138kV line	0.98	Lag	100.8	-18.2
	Weatherford (521092) to Hydro. (520950) 138kV line	1.00	Lag	100.8	-8.2
	Elk City (511458) to Clinton AFB (511446) 138kV line	1.00	Lag	100.8	-2.7
	Elk City 138kV (511458) to 230kV (511490) transformer	0.99	Lag	100.8	-13.5
	Gracemont 138kV (515802 to 345kV (515800) transformer	0.99	Lag	100.8	-11.1
	Hobart Jct (511463) to Carnegie South (511445) 138kV line	1.00	Lag	100.8	-5.5
	Hobart Jct. (511463) to Omaltus4 (529302) 138kV line	0.99	Lag	100.8	-12.4
	Hobart Jct. (511463) 138/69kv auto	1.00	Lag	100.8	-10.5
	Altus (511440) to Snyder (511435) 138kV line	0.99	Lag	100.8	-13.2
	Moorewood (521001) to Mooreland (520999) 138kV line	1.00	Lead	100.8	7.4
	Anadarko (520814) to Southwest (511477) 138kV line	0.99	Lag	100.8	-13.2
	Anadarko (520814) to Gracemont (515802) 138kV line	0.99	Lag	100.8	-11.9
	Washita (521089) to Gracemont (515802) 138kV line	0.99	Lag	100.8	-12.4
	GEN-2008-037 (573570) to Gracemont (515802) 138kV line	0.99	Lag	100.8	-12.5
	Anadarko (520814) to Cornville Tap (520867) 138kV line	0.99	Lag	100.8	-11.8
	Southwest (511477) to Washita (521089) 138kV line	1.00	Lag	100.8	-8.7
	Oney (521017) to Washita (521089) 138kV line	1.00	Lag	100.8	-9.3
	Clinton Jct (511485) to Elk City (511458) 138kV line	1.00	Lag	100.8	-9
	Washita (521089) to GEN-2008-037 (573570) 138kV line	0.99	Lag	100.8	-12.9
	Brantley (520832) to Durham (520885) 138kV line	0.99	Lag	100.8	-11
	Brantley (520832) to Moorwood (521002) 138kV line	1.00	Lag	100.8	-7.4
	Elk City 138kV (511458) to 69kV (511459) transformer	1.00	Lag	100.8	-10.1
	Sweet Water (511541) to Wheeler (523777) 230 kV line	0.99	Lead	100.8	11.4

CASE	CONTINGENCY	POWER FACTOR		MW @ POI	VARGEN MVAR
WP	BASE CASE	0.99	Lag	100.8	-12.4
	Weatherford (521092) to Clinton (520856) 138kV line	1.00	Lag	100.8	-0.3
	Clinton Jct. (511485) to CL_NGTP (511534) 138kV line	0.99	Lag	100.8	-17.3
	Weatherford (521092) to Hydro. (520950) 138kV line	1.00	Lag	100.8	-7.2
	Elk City (511458) to Clinton AFB (511446) 138kV line	1.00	Lag	100.8	-1.2
	Elk City 138kV (511458) to 230kV (511490) transformer	0.99	Lag	100.8	-17.1
	Gracemont 138kV (515802 to 345kV (515800) transformer	0.99	Lag	100.8	-11.0
	Hobart Jct (511463) to Carnegie South (511445) 138kV line	1.00	Lag	100.8	-5.5
	Hobart Jct. (511463) to Omaltus4 (529302) 138kV line	0.99	Lag	100.8	-11.3
	Hobart Jct. (511463) 138/69kv auto	0.99	Lag	100.8	-11.2
	Altus (511440) to Snyder (511435) 138kV line	0.99	Lag	100.8	-12.7
	Moorewood (521001) to Mooreland (520999) 138kV line	1.00	Lead	100.8	8.0
	Anadarko (520814) to Southwest (511477) 138kV line	0.99	Lag	100.8	-12.1
	Anadarko (520814) to Gracemont (515802) 138kV line	0.99	Lag	100.8	-11.2
	Washita (521089) to Gracemont (515802) 138kV line	0.99	Lag	100.8	-12.0
	GEN-2008-037 (573570) to Gracemont (515802) 138kV line	0.99	Lag	100.8	-12.4
	Anadarko (520814) to Cornville Tap (520867) 138kV line	0.99	Lag	100.8	-11.7
	Southwest (511477) to Washita (521089) 138kV line	0.99	Lag	100.8	-10.5
	Oney (521017) to Washita (521089) 138kV line	1.00	Lag	100.8	-9.0
	Clinton Jct (511485) to Elk City (511458) 138kV line	1.00	Lag	100.8	-7.7
	Washita (521089) to GEN-2008-037 (573570) 138kV line	0.99	Lag	100.8	-14.0
	Brantley (520832) to Durham (520885) 138kV line	0.99	Lag	100.8	-10.7
	Brantley (520832) to Moorwood (521002) 138kV line	1.00	Lag	100.8	-5.1
	Elk City 138kV (511458) to 69kV (511459) transformer	0.99	Lag	100.8	-12.6
	Sweet Water (511541) to Wheeler (523777) 230 kV line	0.99	Lead	100.8	15.0

2.3. Conclusions

The results of the power factor analysis showed that with the MVAR capability of the GE 1.6 MW WTG and without reactive compensation, the power factor at the POI would be from 0.98 to 1.00 for summer peak conditions and 0.99 to 1.00 for winter peak conditions.

Section 3. Stability Analysis

3.1. 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.

3.2. Faults Simulated

Forty-four (44) 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 current practice. The previous queued projects shown in Table 1-1 and units in areas 520, 524, 525, 526, 531, 534 and 536 were monitored in the simulations. Table 3-1 shows the list of simulated contingencies with corresponding clearing times.

Table 3-1 List of Simulated Faults

CONT. NO.	CONT. NAME	FAULT DESCRIPTION
1	FLT01-3PH	3 phase fault on the Weatherford WFEC (GEN-2009-030) (521092) to Clinton. (520856) 138kV line, near Weatherford. a. Apply fault at the Weatherford 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.
2	FLT02-1PH	SLG fault on the Weatherford WFEC (GEN-2009-030) (521092) to Clinton. (520856) 138kV line, near Weatherford. a. Apply fault at the Weatherford 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.
3	FLT03-3PH	3 phase fault on the Clinton Jct. (511485) to CL_NGTP (511534) 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.

CONT. NO.	CONT. NAME	FAULT DESCRIPTION
4	FLT04-1PH	SLG fault on the Clinton Jct. (511485) to CL_NGTP (511534) 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.
5	FLT05-3PH	3 phase fault on the Weatherford WFEC (GEN-2009-030) (521092) to Hydro. (520950) 138kV line, near Weatherford. a. Apply fault at the Weatherford 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.
6	FLT06-1PH	SLG fault on the Weatherford WFEC (GEN-2009-030) (521092) to Hydro. (520950) 138kV line, near Weatherford. a. Apply fault at the Weatherford 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.
7	FLT07-3PH	3 phase fault on the Elk City (511458) to Clinton AFB (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.
8	FLT08-1PH	SLG fault on the Elk City (511458) to Clinton AFB (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.
9	FLT09-3PH	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.
10	FLT10-3PH	3 phase fault on the Gracemont 138kV (515802 to 345kV (515800) transformer, near the 138kV bus. a. Apply fault at the Gracemont 138kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.

CONT. NO.	CONT. NAME	FAULT DESCRIPTION
11	FLT11-3PH	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.
12	FLT12-1PH	SLG 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.
13	FLT13-3PH	3 phase fault on the Hobart Jct. (511463) to Omaltus Tap (529302) 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.
14	FLT14-1PH	SLG fault on the Hobart Jct. (511463) to Omaltus Tap (529302) 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.
15	FLT15-3PH	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.
16	FLT16-3PH	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.
17	FLT17-1PH	SLG 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.

CONT. NO.	CONT. NAME	FAULT DESCRIPTION
18	FLT18-3PH	3 phase fault on the Morewood (521001) to Mooreland (520999) 138kV line, near Moorewood. 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.
19	FLT19-1PH	SLG fault on the Morewood (521001) to Mooreland (520999) 138kV line, near Moorewood. 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.
20	FLT20-3PH	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.
21	FLT21-1PH	SLG 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.
22	FLT22-3PH	3 phase fault on the Anadarko (520814) to Gracemont (515802) 138kV line, near Gracemont. a. Apply fault at the Gracemont 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.
23	FLT23-1PH	SLG fault on the Anadarko (520814) to Gracemont (515802) 138kV line, near Gracemont. a. Apply fault at the Gracemont 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.
24	FLT24-3PH	3 phase fault on the Washita (521089) to Gracemont (515802) 138kV line, near Gracemont. a. Apply fault at the Gracemont 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.

CONT. NO.	CONT. NAME	FAULT DESCRIPTION
25	FLT25-1PH	SLG fault on the Washita (521089) to Gracemont (515802) 138kV line, near Gracemont. a. Apply fault at the Gracemont 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.
26	FLT26-3PH	3 phase fault on the GEN-2008-037 (573570) to Gracemont (515802) 138kV line, near GEN-2008-037. a. Apply fault at the GEN-2008-037 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.
27	FLT27-1PH	SLG fault on the GEN-2008-037 (573570) to Gracemont (515802) 138kV line, near GEN-2008-037. a. Apply fault at the GEN-2008-037 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
28	FLT28-3PH	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.
29	FLT29-1PH	SLG 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.
30	FLT30-3PH	3 phase fault on the Southwest (511477) to Washita (521089) 138kV line, near Washita. a. Apply fault at the Washita 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.

CONT. NO.	CONT. NAME	FAULT DESCRIPTION
31	FLT31-1PH	SLG fault on the Southwest (511477) to Washita (521089) 138kV line, near Washita. a. Apply fault at the Washita 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.
32	FLT32-3PH	3 phase fault on the Oney (521017) to Washita (521089) 138kV line, near Washita. a. Apply fault at the Wahsita 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.
33	FLT33-1PH	SLG fault on the Oney (521017) to Washita (521089) 138kV line, near Washita. a. Apply fault at the Wahsita 138kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
34	FLT34-3PH	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.
35	FLT35-1PH	SLG 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.
36	FLT36-3PH	3 phase fault on the Washita (521089) to GEN-2008-037 (573570) 138kV line, near GEN-2008-037. a. Apply fault at the GEN-2008-037 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.
37	FLT37-1PH	SLG fault on the Washita (521089) to GEN-2008-037 (573570) 138kV line, near GEN-2008-037. a. Apply fault at the GEN-2008-037 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.

CONT. NO.	CONT. NAME	FAULT DESCRIPTION
38	FLT38-3PH	3 phase fault on the Brantley (520832) to Durham (520885) 138kV line, near Brantley. a. Apply fault at the Brantley 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.
39	FLT39-1PH	SLG fault on the Brantley (520832) to Durham (520885) 138kV line, near Brantley. a. Apply fault at the Brantley 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	FLT40-3PH	3 phase fault on the Brantley (520832) to Morwood (521002) 138kV line, near Brantley. a. Apply fault at the Brantley 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.
41	FLT41-1PH	SLG fault on the Brantley (520832) to Morwood (521002) 138kV line, near Brantley. a. Apply fault at the Brantley 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	FLT42-3PH	3 phase fault on the Elk City 138kV (511458) to 69kV (511459) 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.
43	FLT43-3PH	3 phase fault on the Sweet Water (511541) to Wheeler (523777) 230kV line, near Sweet Water 230 kV. a. Apply fault at the Sweet Water 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line.
44	FLT44-1PH	SLG fault on the Sweet Water (511541) to Wheeler (523777) 230kV line, near Sweet Water 230 kV. a. Apply fault at the Sweet Water 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line.

Simulations were performed with a 0.1-second steady-state run followed by the appropriate disturbance as described in Table 3-1. Simulations were run for a minimum 10-second duration to confirm proper machine damping.

3.3. Simulation Results

Forty-four (44) faults were considered for transient stability simulations which included 3-phase faults as well as 1-phase-to-ground faults at locations defined by

SPP. The results of the simulations showed neither angular nor voltage instability problems for the forty-four faults. Although there are some oscilatory responses for Blue Canyon I and Blue Canyon II units, for some of the contingencies studied, these are related to a modeling issue regarding the Vestas dynamic models for these two units. The study then concludes that the interconnection of the proposed 100.8 MW Project does not impact the stability performance of the SPP system for the faults tested on the supplied base cases.

Section 4. Conclusions

The findings of GEN-2009-016 impact re-study are as follows:

1. The results of the power factor analysis showed that with the MVAR capability of the GE 1.6 MW WTG and without reactive compensation, the power factor at the POI would be from 0.98 to 0.99 in summer and 0.99 to 1.00 in winter.
2. Forty-four (44) faults were considered for transient stability simulations which included 3-phase faults as well as 1-phase-to-ground faults at locations defined by SPP. The results of the simulations showed neither angular nor voltage instability problems for the forty-four faults. Although there are some oscilatory responses for Blue Canyon I and Blue Canyon II units, for some of the contingencies studied, these are related to a modeling issue regarding the Vestas dynamic models for these two units. The study then concludes that the interconnection of the proposed 100.8 MW Project does not impact the stability performance of the SPP system for the faults tested on the supplied base cases.