Impact Study for Generation Interconnection Request GEN-2009-025 Impact Restudy

SPP Generation Interconnection Studies

GEN-2009-025

October 2011

Executive Summary

The GEN-2009-025 interconnection request was first studied as part of the DISIS-2009-001 Definitive Impact Study, Cluster Group 8, which was originally posted in January 2010, with a subsequent restudy posted on 2/5/2010. With the power factor requirements, and all network upgrades in service, all interconnection requests in Group 8 will meet FERC Order #661A low voltage ride through (LVRT) requirements and the transmission system will remain stable.

The interconnection customer requested a restudy of GEN-2009-025 (posted 6/7/2010) for a change in wind turbine generator manufacturer from GE 1.5MW machines to Vestas 1.8MW machines. The study found a significant voltage drop and wind turbine instability and oscillations for the outage of the line from GEN-2009-025 to the Sinclair Blackwell substation, and that additional reactive support (a 34.5kV +/- 10 MVA STATCOM device) is required at the wind farm substation to be installed at the interconnection customer's expense.

The interconnection customer has requested a second restudy to evaluate the effects of changing the wind turbine generator manufacturer from the Vestas 1.8MW machines to the Siemens 2.3MW machines. The requested In-Service Date is 12/31/2011. The point of interconnection is a tap on the Deer Creek to Sinclair Blackwell 69kV transmission line. The aggregate wind farm power output is 59.8MW (26 machines at 2.3MW per machine). The attached report is the findings of this restudy.

The findings of the restudy show that no stability problems were found during the summer or the winter peak conditions due to the use of the Siemens 2.3MW wind turbine generators*.

A 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-2009-025 can interconnect 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.

*Summer Peak and Winter Peak Stability Plots Available Upon Request (126 pages).

Pterra Consulting

Technical Report R139-11

Interconnection Impact Re-study for GEN-2009-025

Submitted to

Southwest Power Pool

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Executive Summary

This report presents the results of GEN-2009-025 (the "Project") impact re-study comprising of power factor and stability analyses. The Project has a nominal 59.8 MW maximum rating studied using Siemens 2.3 MW wind turbine generators ("WTGs"). The Point of Interconnection ("POI") is the Tap on Deer Creek-Sinclair Blackwell 69 kV line.

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 59.8 MW.

Two base cases, 2011 summer peak and 2011 winter peak conditions, each comprising of a power flow and corresponding dynamics database were provided by SPP.

Power Factor Test

The power factor test showed that the power factor requirements for GEN-2009-025 are 95.7% lagging (absorbing) and 99.9% lagging (absorbing) for summer and 97.4% lagging (absorbing) and 99.8 lagging (absorbing) for winter.

Stability Simulations

Twenty-one (21) faults were considered for the transient stability simulations which include three-phase faults and single-line-to-ground faults at the locations defined by SPP. The results of the simulation showed neither angular nor voltage instability problems in the SPP system for the twenty-one faults. The study finds that the interconnection of the proposed project does not impact the stability performance of the SPP system for the faults tested on the supplied base cases.

Section 1. Introduction

1.1. Project Overview

This report presents the results of GEN-2009-025 (the "Project") impact re-study comprising of power factor and stability analyses. The Project has a nominal 59.8 MW maximum rating studied using Siemens 2.3 MW wind turbine generators. The point of interconnection is the Tap on Deer Creek-Sinclair Blackwell kV line.

Figures 1-1 shows the interconnection diagram of the Project to SPP's system as modeled in the power flow cases.

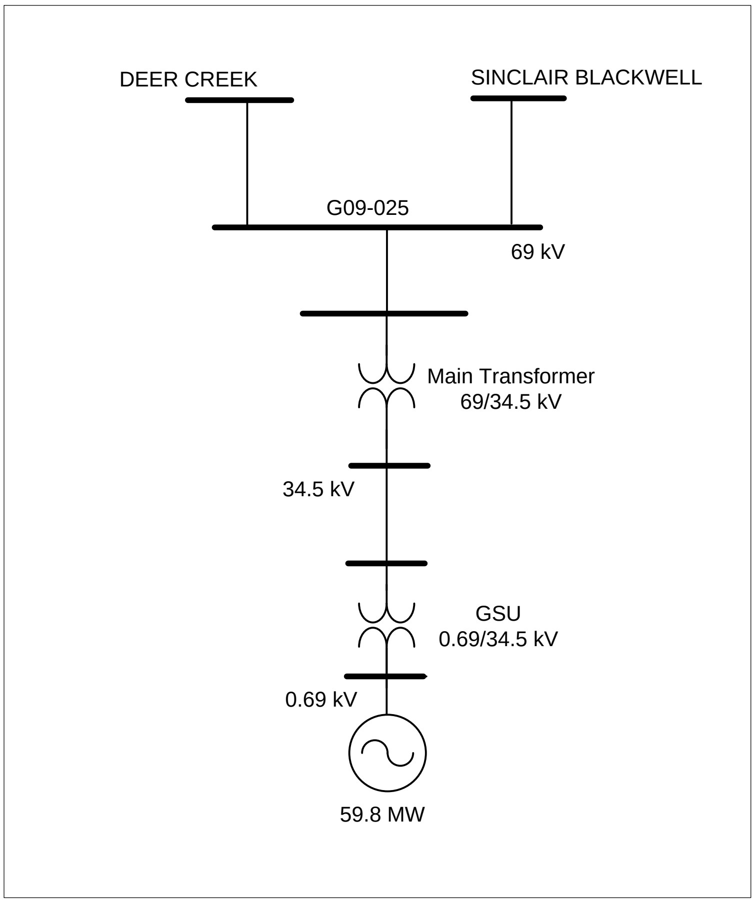

Figure 1-1 Power Flow Model for Gen-2009-025

Table 1-1 shows the list of other projects which are concurrent with the study project and Table 1-2 shows prior-queued projects modeled in the base cases.

Table 1-1 List of Other Projects Concurrent with the Study Project

Request	Size (MW)	Wind Turbine Model	Point of Interconnection
GEN-2008-071	76.8	GE 1.6MW	Newkirk 138kV (514759)
GEN-2008-098	100.8	Vestas V90 1.8MW	Wolf Creek (532797) – LaCygne (542981) 345kV
GEN-2010-003	100.8	Vestas V90 1.8MW	Gen-2008-098 (572090) addition
GEN-2010-005	299.2	GE 1.6MW	Gen-2007-025 (532781) 345kV

Table 1-2 List of Prior-Queued Projects

Request	Size (MW)	Generator Model	Point of Interconnection
GEN-2002-004	199.5	GE 1.5MW	Latham 345kV (532800)
GEN-2005-013	199.8	Vestas V90 1.8MW	Latham – Neosho 345kV (574000)
GEN-2007-025	299.2	GE 1.6MW	Wichita-Woodring 345kV (532781)
GEN-2008-013	300	GE 1.5MW	Wichita – Woodring 345kV (579406)
GEN-2008-021	1250	Nuclear Steam Turbine	Wolf Creek 345kV (532751)
GEN-2008-127	200.1	Siemens 2.3MW	Tap Sooner (514803) – Rose Hill (532794) 345kV (573039)

1.2. Objectives

The objectives of the study are to conduct power factor analysis and to determine the impact on system stability of interconnecting the proposed wind farms 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. Turn off the Project wind farm as modeled (as well as prior 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. If the required power factor at the POI is beyond the capability of the studied wind turbines, capacitor banks may be considered for the stability analysis. The preference is to locate the capacitance banks 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

The 59.8 MW Project wind farm was turned off in the power flow model. A 59.8 MW plant with no VAR capability was modeled at the Project's 69 kV bus. A VAR generator was also modeled at the same bus and was set to hold pre-contingency voltage at POI in the provided power flow models, 1.033 for summer and 1.031 for winter.

Results of the test showed that the var generator absorbs reactive power in all the specified contingencies as summarized in Table 2-1. The highest and lowest values obtained are as follows:

1. For the summer case, the var generator absorbs 18.2 MVAR (highest) for the loss of GEN-2009-025–Deer Creek 69 kV line and 3.0 MVAR (lowest) for the loss of GEN-2009-025–Sinclair Blackwell 69 kV line.
2. For the winter case, the var generator absorbs 13.9 MVAR (highest) for the loss of Osage-Webb City Tap 138 kV line and 4.1 MVAR (lowest) for the loss of Chicasia 138/69 kV transformer.
3. The corresponding power factor requirements for GEN-2009-025 are 95.7% lagging (absorbing) for summer and 97.4% lagging (absorbing) for winter.

Table 2-1 VAR Generator Output in Summer and Winter Peak Cases for GEN-2009-025

CASE	CONTINGENCY	POWER FACTOR		MW @ POI	VARGEN MVAR
SP	BASE CASE	0.975	Lag	59.8	-13.5
	GEN-2009-025 - SINCLAIR BLACKWELL 69 KV LINE	0.999	Lag	59.8	-3.0
	GEN-2009-025 - DEER CREEK 69 KV LINE	0.957	Lag	59.8	-18.2
	KILDARE - NEWKIRK 138 KV LINE	0.984	Lag	59.8	-11.0
	OSAGE - WEBB CITY TAP 138 KV LINE	0.972	Lag	59.8	-14.4
	SOONER - SOONER PUMP TAP 138 KV LINE	0.986	Lag	59.8	-10.1
	SOONER - MILLER 138 KV LINE	0.987	Lag	59.8	-9.9
	OSAGE - MARLAND TAP 138 KV LINE	0.974	Lag	59.8	-13.8
	NEWKIRK - PECKHAM TAP 138 KV LINE	0.982	Lag	59.8	-11.5
	KREMLIN - NE ENID 69 KV LINE	0.985	Lag	59.8	-10.6
	DELAWARE - NORTHEASTERN 345 KV LINE	0.976	Lag	59.8	-13.4
	NE ENID 138/69 KV TRANSFORMER	0.978	Lag	59.8	-12.8
	CHIKASIA 138/69 KV TRANSFORMER	0.997	Lag	59.8	-4.4
WP	BASE CASE	0.976	Lag	59.8	-13.2
	GEN-2009-025 - SINCLAIR BLACKWELL 69 KV LINE	0.991	Lag	59.8	-8.3
	GEN-2009-025 - DEER CREEK 69 KV LINE	0.983	Lag	59.8	-11.2
	KILDARE - NEWKIRK 138 KV LINE	0.976	Lag	59.8	-13.3
	OSAGE - WEBB CITY TAP 138 KV LINE	0.974	Lag	59.8	-13.9
	SOONER - SOONER PUMP TAP 138 KV LINE	0.986	Lag	59.8	-10.2
	SOONER - MILLER 138 KV LINE	0.986	Lag	59.8	-10.1
	OSAGE - MARLAND TAP 138 KV LINE	0.976	Lag	59.8	-13.3
	NEWKIRK - PECKHAM TAP 138 KV LINE	0.974	Lag	59.8	-13.8
	KREMLIN - NE ENID 69 KV LINE	0.984	Lag	59.8	-11.0
	DELAWARE - NORTHEASTERN 345 KV LINE	0.977	Lag	59.8	-13.1
	NE ENID 138/69 KV TRANSFORMER	0.975	Lag	59.8	-13.5
	CHIKASIA 138/69 KV TRANSFORMER	0.998	Lag	59.8	-4.1

2.3. Conclusion

The power factor test showed that the power factor requirements for GEN-2009-025 are 95.7% lagging (absorbing) and 99.9% lagging (absorbing) for summer and 97.4% lagging (absorbing) and 99.8 lagging (absorbing) for winter.

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

Twenty-one (21) faults were considered for the transient stability simulations which included three phase and 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. Other projects and prior queued projects shown in Tables 1-1 and 1-2 and units in areas 520, 523, 524, 525, 536, 540, and 541 were monitored in the simulations.

Table 3-1 shows the list of simulated contingencies. It also shows the fault clearing time and the time delay before re-closing for all the study contingencies.

Table 3-1 List of Simulated Faults

Cont. No.	Cont. Name	Description
1	FLT01-3PH	3 phase fault on the GEN-2009-025 (573049) to Sinclair Blackwell (514728) 69kV line, near GEN-2009-025. a. Apply fault at the GEN-2009-025 69kV 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 GEN-2009-025 (573049) to Deer Creek (514741) 69kV line, near GEN-2009-025. a. Apply fault at the GEN-2009-025 69kV 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 Kildare (514760) to Newkirk (514759) 138kV line, near Kildare. a. Apply fault at the Kildare 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	Single phase fault and sequence like previous
7	FLT07-3PH	3 phase fault on the Osage (514743) to Webb City Tap (510376) 138kV line, near Osage. a. Apply fault at the Osage 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 Sooner (514802) to Sooner Pump Tap (514798) 138kV line, near Sooner. a. Apply fault at the Sooner 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 Sooner (514802) to Miller (514704) 138kV line, near Sooner. a. Apply fault at the Sooner 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	Description
12	FLT12-1PH	Single phase fault and sequence like previous
13	FLT13-3PH	3 phase fault on the Osage (514743) to Marland Tap (514770) 138kV line, near Osage. a. Apply fault at the Osage 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 Newkirk (514759) to Peckham Tap (515381) 138kV line, near Newkirk. a. Apply fault at the Newkirk 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
17	FLT17-3PH	3 phase fault on the Kremlin (514712) to NE Enid (514732) 69kV line, near Kremlin. a. Apply fault at the Kremlin 69kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
18	FLT18-1PH	Single phase fault and sequence like previous
19	FLT19-3H	3 phase fault on the Delaware (510380) to Northeastern (510406) 345kV line, near Delaware. a. Apply fault at the Delaware 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	FLT20-3PH	3 phase fault on the NE Enid 69kV (514732) to 138kV (514769) transformer, near the 69kV bus. a. Apply fault at the NE Enid 69kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
21	FLT21-3PH	3 phase fault on the Chikasia 138kV (514757) to 69V (514756) transformer, near the 138 kV bus. a. Apply fault at the Chikasia 138kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.

The simulations were performed with a 0.5-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

The stability simulations with the twenty-one specified test faults did not find any angular or voltage instability problems in the SPP system the Project. The study finds that the interconnection of the proposed 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-2009-025 impact re-study are as follows:

1. The power factor test showed that the power factor requirements for GEN-2009-025 are 95.7% lagging (absorbing) and 99.9% lagging (absorbing) for summer and 97.4% lagging (absorbing) and 99.8% lagging (absorbing) for winter.
2. The stability simulations with the twenty-one specified test faults did not find any angular or voltage instability problems in the SPP system. The study finds that the interconnection of the proposed project does not impact the stability performance of the SPP system for the faults tested on the supplied base cases.