Impact Study For Generation Interconnection Request GEN-2007-017

SPP Tariff Studies
(#GEN-2007-017)

August 2008

Summary

Pursuant to the tariff and at the request of Southwest Power Pool (SPP), S&C Electric Company performed the following Impact Study to satisfy the Impact Study Agreement executed by the requesting customer and SPP for SPP Generation Interconnection request GEN-2007-017. The request for interconnection was placed with SPP in accordance SPP's Open Access Transmission Tariff, which covers new generation interconnections on SPP's transmission system.

<OMITTED TEXT> (Customer) has requested an Impact Study for the purpose of interconnecting 99 MW of wind generation within the control area of Missouri Public Service (MIPU) located in Nodaway County, Missouri. The proposed method of interconnection is a new 161 kV line terminal and breaker to be installed at a new ring-bus switching station to be located on the existing Maryville – Midway 161 kV transmission line, owned by MIPU. This new station was previously proposed for construction for Generation Interconnect Requests #GEN-2006-014 and #GEN-2006-017. The proposed in-service date is November 30, 2009.

Power Factor Requirements

The Customer has requested to study GE 1.5 MW wind turbines for this generation interconnection request. The GE wind turbines have capability of +/- 95% lead/lag power factor at the generator terminals. An analysis was conducted to determine whether the GE turbines are sufficient to meet the power factor criteria for the wind farm in lieu of the earlier specified 14 Mvars of 34.5kV capacitors specified in the Feasibility Study.

The interconnection generators were set to hold a voltage schedule at the point of interconnection, the new MIPU 161kV substation, of 1.0 per unit voltage under system intact conditions and the two most stringent contingencies that the wind farm will be subjected. For this analysis, all previous queued generation interconnection requests were included. The analysis was conducted for both the 2008 summer and 2008 winter peak. The results of the analysis are below.

SEASON	CONTINGENCY	PF @POI	PF	MW @POI	Mvars @POI
08SP	NONE	0.996	Lag	665	-52
08SP	TAP-014 - Clarinda 161kV	0.999	Lag	665	-11
08SP	TAP-014 – Maryville 161kV	0.999	Lag	665	-10
08SP	TAP-014 – Midway 161kV	0.997	Lag	665	-31
08WP	NONE	0.996	Lag	665	-64
08WP	TAP-014 - Clarinda 161kV	0.999	Lag	665	-25
08WP	TAP-014 – Maryville 161kV	0.999	Lag	665	-24
08WP	TAP-014 – Midway 161kV	0.997	Lag	665	-53

The analysis determined that the customer will need to be able to provide unity power factor at the point of interconnection for any system configuration. The Customer will need to purchase the General Electric turbines with the manufacturer's wind var system to maintain the acceptable voltage schedule at the point of interconnection. Using the GE turbines and the manufactuer's wind var system, a capacitor bank will not be necessary for the interconnection.

Interconnection Facilities

The requirements for interconnection of the 99 MW consist of adding a new 161 kV line terminal and breaker to be installed at a new ring-bus switching station to be located on the existing Maryville – Midway 161 kV transmission line, owned by MIPU. This new station was previously proposed for construction for Generation Interconnect Requests #GEN-2006-014 and #GEN-2006-017. A preliminary one-line drawing of the interconnection facilities are shown in Figure 1. The Customer did not propose a specific route of its 161 kV line to serve its 161/34.5 kV collection system facilities. It is assumed that obtaining all necessary right-of-way for construction of the Customer 161 kV transmission line and the 161/34.5 kV collector substation will not be a significant expense.

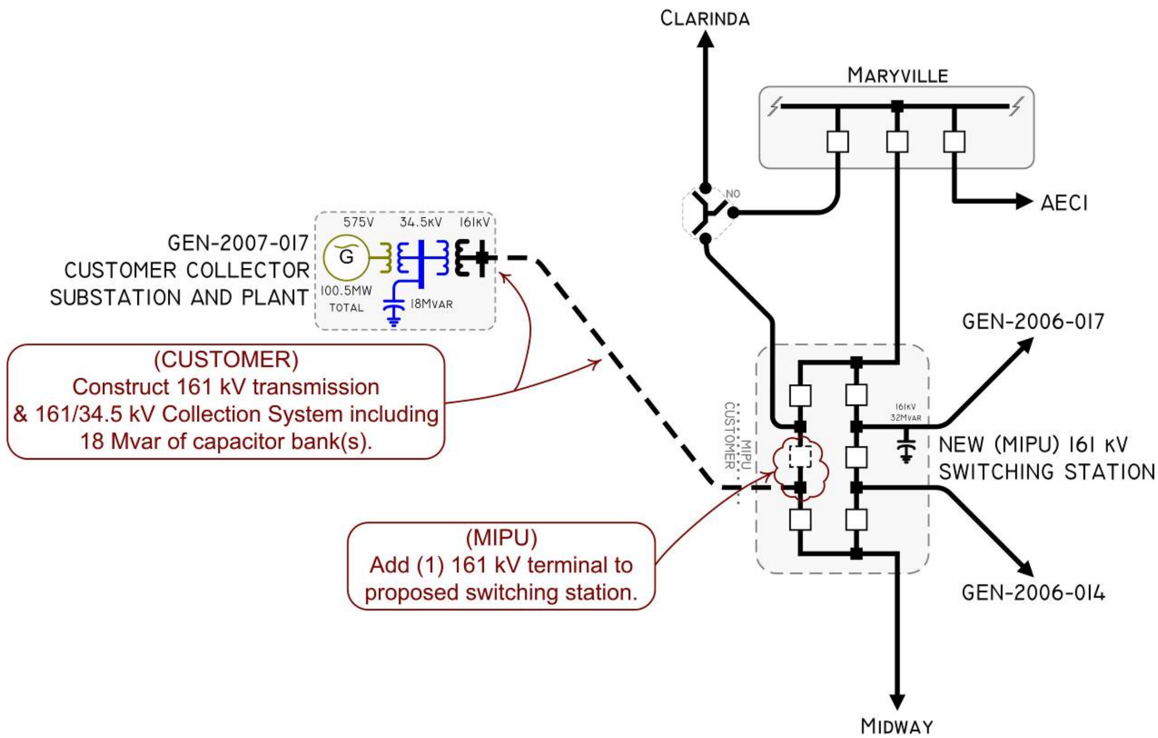

Figure 1: Proposed Method of Interconnection

(Final design to be determined)

Table 1: Direct Assignment Facilities

FACILITY	**ESTIMATED COST** (2008 DOLLARS)
CUSTOMER – (1) 161/34.5 kV Customer collector substation facilities.	*
CUSTOMER – (1) 161 kV transmission line from Customer collector substation to the proposed station to be located on the Maryville – Midway 161 kV transmission line.	*
CUSTOMER – 34.5 kV, 18 Mvar capacitor bank(s) to be installed in the Customer 161/34.5 kV collector substation.	*
CUSTOMER – Right-of-Way for all Customer facilities.	*
MIPU – (1) 161 kV line terminal and breaker for GI Request #GEN-2007-017	500,000
TOTAL	**500,000**

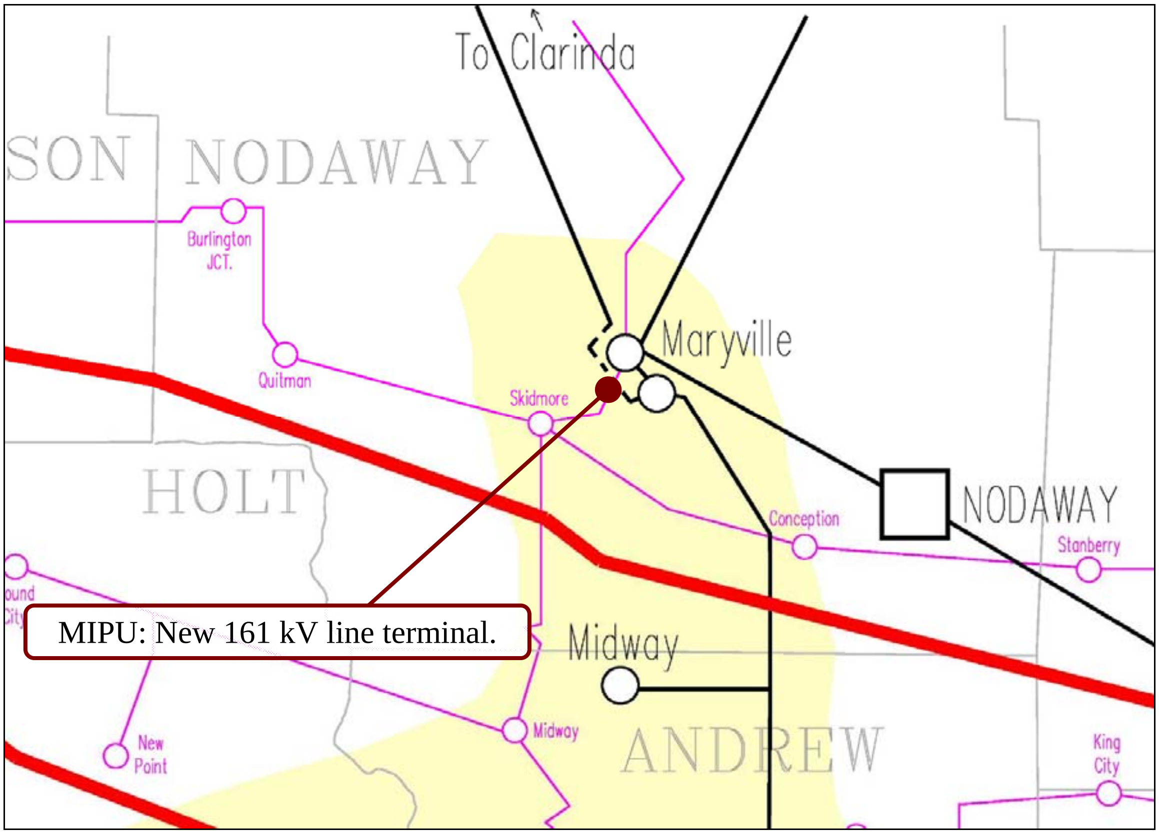

Figure 2: Point of Interconnection Area Map

Final Report

For

Southwest Power Pool

From

S&C Electric Company

IMPACT STUDY FOR GENERATION INTERCONNECTION REQUEST GEN-2007-017

S&C Project No. 3141

August 5, 2008

S&C Electric Company

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Executive Summary

This system impact study was performed in response to a generation interconnection study request through the Southwest Power Pool Tariff for a 99 MW wind farm in Nodaway County, Missouri. The Wind Project will use GE 1.5 MW wind turbine generators and interconnect into the new 161 kV Missouri Public Service (MIPU) ring bus substation planned for GEN-2006-014 and GEN-2006-017. The objective of this study is to determine the impact of the interconnection on the stability of nearby areas and prior queued projects for winter peak (with facilities planned for 2008) and summer peak (with facilities planned for 2008) cases. Steady-state and dynamic studies were performed at full load.

SPP requires the project to maintain unity power factor at the POI under normal operating conditions. The GE wind turbine option will require a WFMS (Wind Farm Management System) to dynamically control the power factor setpoint of wind turbines to compensate for collector and transformation losses in response to nearby transmission grid changes and variations in wind farm production levels in order to maintain unity power factor at the POI. Mechanically switched capacitor banks will not be required either at 34.5 kV or 161 kV.

Three-phase and single-phase-to-ground faults were studied at locations specified by SPP. Dynamic stability results show that nearby areas remain stable for all fault contingencies. The interconnection will satisfy low-voltage ride through provisions in FERC Order 661A with the GE option using the LVRT II package.

1. Introduction

This system impact study was performed in response to a generation interconnection study request through the Southwest Power Pool Tariff for a 99 MW wind farm in Nodaway County, Missouri. The Wind Project will use GE 1.5 MW wind turbine generators and interconnect into the new 161 kV Missouri Public Service (MIPU) ring bus substation planned for GEN-2006-014 and GEN-2006-017. The single-line-diagram (Figure 1) shows the Maryville Substation, Clarinda Substation, Midway Substation, GEN-2006-017 Wind Project, GEN-2007-014 Wind Project and the proposed GEN-2007-017 Wind Project interconnected through six breakers into the new MIPU ring bus substation.

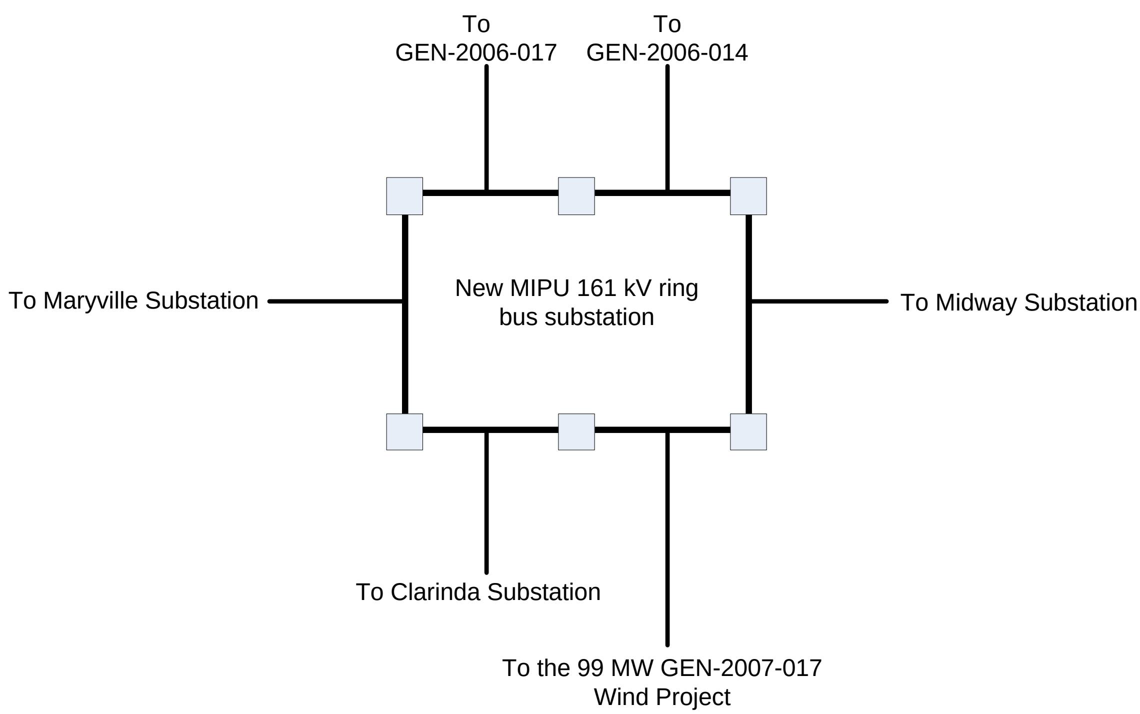

Figure 1: 161 kV Missouri Public Service ring bus configuration

The objective of this study is to determine the impact of the interconnection on the stability of nearby areas and prior queued projects for winter peak (with facilities planned for 2008) and summer peak (with facilities planned for 2008) cases. Steady-state and dynamic studies were performed at full load.

2. Load Flow Model

The customer provided a collector system layout and impedance information. Each feeder is represented as aggregated generators to simplify representation in PSS/E. Transformer fixed taps were selected after looking at operating voltages within the wind farm.

Table 1: GEN-2007-017 load flow parameters

Feeder 1	Parameters
16 GE 1.5 MW wind turbine generators at 0.575 kV	16 * 1.5 MW = 24 MW 16 * 1.667 MVA = 26.672 MVA Power factor at 0.575 kV bus: 0.985 lagging
16 Pad mounted wind turbine generator transformers 0.575 / 34.5 kV transformers	16 * 1.75 MVA = 28 MVA X/R = 7.5 %IZ = 5.75 Z1 = 0.0275 + 0.20679j p.u. on 100 MVA base No load tap = flat
Equivalent 34.5 kV circuit impedance	Z1 = 0.0302 + 0.0274j p.u. on 100 MVA base B1 = 0.0059 p.u. on 100 MVA base

Feeder 2	Parameters
16 GE 1.5 MW wind turbine generators at 0.575 kV	16 * 1.5 MW = 24 MW 16 * 1.667 MVA = 26.672 MVA Power factor at 0.575 kV bus: 0.985 lagging
16 Pad mounted wind turbine generator transformers 0.575 / 34.5 kV transformers	16 * 1.75 MVA = 28 MVA X/R = 7.5 %IZ = 5.75 Z1 = 0.0275 + 0.20679j p.u. on 100 MVA base No load tap = flat
Equivalent 34.5 kV circuit impedance	Z1 = 0.0331 + 0.0312j p.u. on 100 MVA base B1 = 0.0064 p.u. on 100 MVA base

Feeder 3	Parameters
17 GE 1.5 MW wind turbine generators at 0.575 kV	17 * 1.5 MW = 25.5 MW 17 * 1.667 MVA = 28.34 MVA Power factor at 0.575 kV bus: 0.985 lagging
17 Pad mounted wind turbine generator transformers 0.575 / 34.5 kV transformers	17 * 1.75 MVA = 29.75 MVA X/R = 7.5 %IZ = 5.75 Z1 = 0.02588 + 0.19462j p.u. on 100 MVA base No load tap = flat
Equivalent 34.5 kV circuit impedance	Z1 = 0.0356 + 0.0359j p.u. on 100 MVA base B1 = 0.0074 p.u. on 100 MVA base

Table 1: GEN-2007-017 load flow parameters (Continued)

Feeder 4	Parameters
17 GE 1.5 MW wind turbine generators at 0.575 kV	17 * 1.5 MW = 25.5 MW 17 * 1.667 MVA = 28.34 MVA Power factor at 0.575 kV bus: 0.985 lagging
17 Pad mounted wind turbine generator transformers 0.575 / 34.5 kV transformers	17 * 1.75 MVA = 29.75 MVA X/R = 7.5 %IZ = 5.75 Z1 = 0.02588 + 0.19462j p.u. on 100 MVA base No load tap = flat
Equivalent 34.5 kV circuit impedance	Z1 = 0.0384 + 0.0397j p.u. on 100 MVA base B1 = 0.0079 p.u. on 100 MVA base

Substation	Parameters
161 kV Transmission line	Z1 = 0.0011 + 0.0029j p.u. on 100 MVA base B1 = (negligible)
34.5/161 kV main step-up transformer	MVA ratings = 67/89/112 MVA (OA/FA/FA) X/R = 28 %IZ = 9 on self-cooled MVA rating Z1 = 0.00321 + 0.08994j p.u. on 67 MVA base No load tap = 5% above (169.05 kV)

2.1. Modeling of Wind Turbine Generators in Load Flow

General Electric 1.5 MW Wind Turbine Generators

Step up 0.575/34.5 kV transformers and aggregated generators were added automatically by the GE IPLAN. SPP requires the project to maintain unity power factor at the POI under normal operating conditions. This will require a WFMS (Wind Farm Management System) to dynamically control the power factor setpoint of wind turbines to compensate for collector and transformation losses in response to nearby transmission grid changes and variations in wind farm production levels in order to maintain unity power factor at the POI. Mechanically switched capacitor banks will not be required either at 34.5 kV or 161 kV. The power factor at each wind turbine generator was manually set to 0.985 lagging (capacitive) to achieve zero exchange at the POI in the load flow case.

Figure 2 and 3 are power flow diagrams of the interconnection with nearby transmission lines for the winter and summer 2008 seasonal cases respectively.

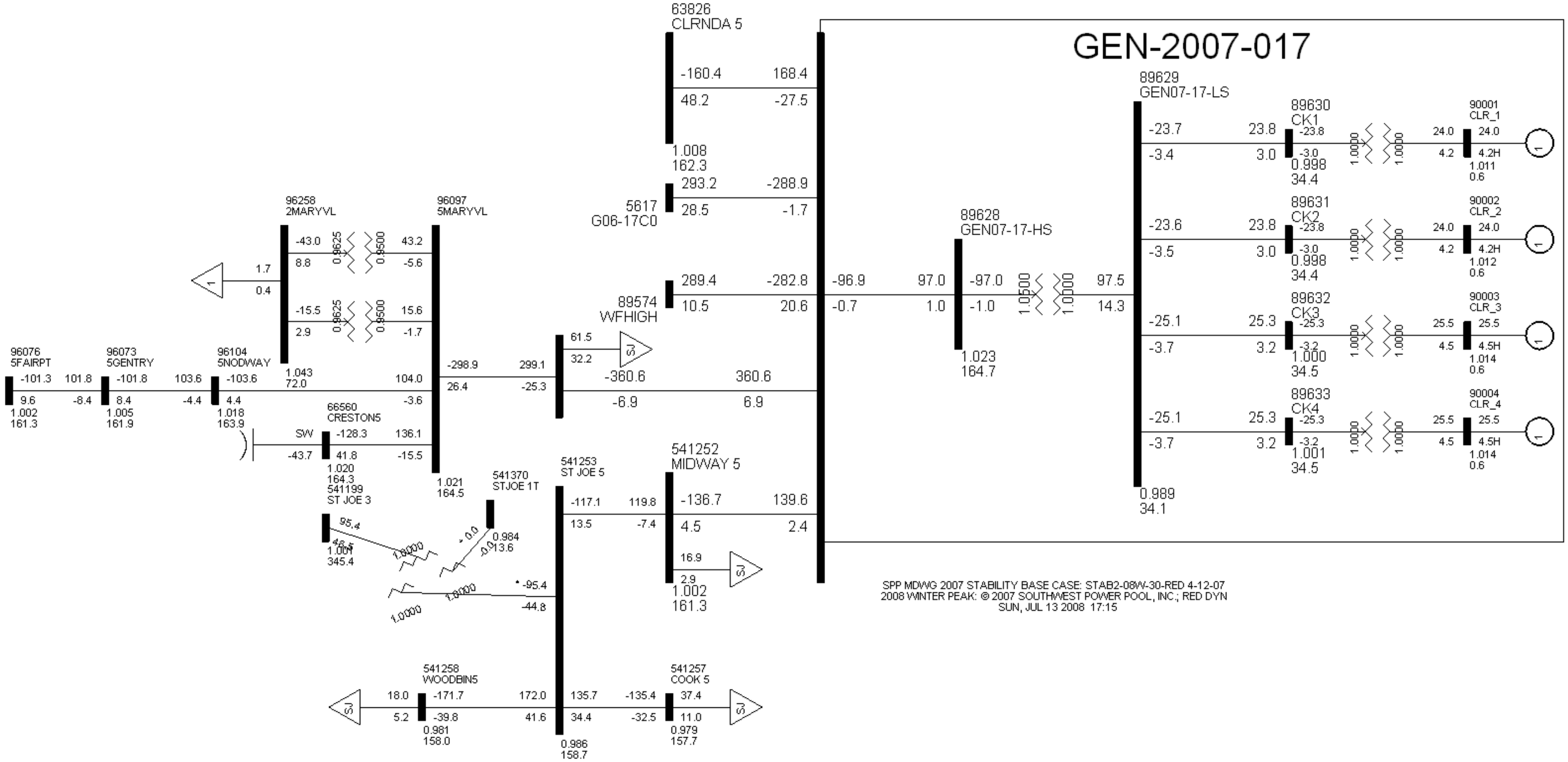

Figure 2: GEN-2007-017 and nearby buses for winter peak 2008

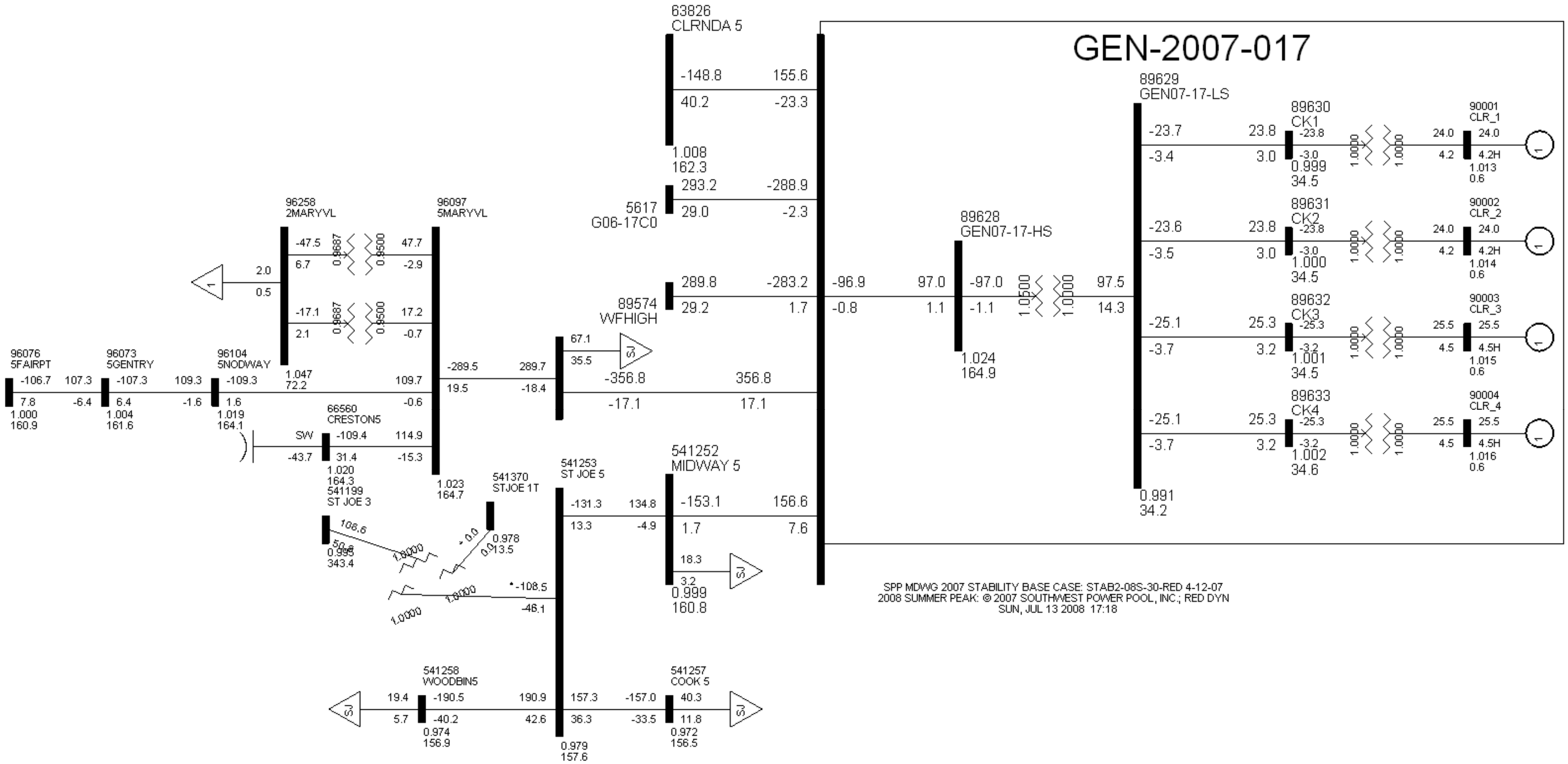

Figure 3: GEN-2007-017 and nearby buses for summer peak 2008

3. Dynamic Stability Analysis

Dynamic simulations were performed for fault contingencies in Table 2 with and without GEN-2007-017.

Table 2: Fault Contingencies Evaluated

Cont. No.	*Cont. Name*	*Description*
1	*FLT13PH*	3 phase fault on the Wind Farm Station (#89572) - Maryville (#541251) 161kV line, near the wind farm. a. Apply fault at the Wind Farm Station (#89572). b. Clear fault after 5 cycles by tripping the line from the Wind Farm - Maryville 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	FLT21PH	*Single phase fault and sequence like Cont. No. 1*
3	*FLT33PH*	3 phase fault on the Wind Farm (#89572) - Midway (541252) 161kV line, near the wind farm. a. Apply fault at the Wind Farm. b. Clear fault after 5 cycles by tripping the line from the Wind Farm - Midway 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 Cont. No.3*
5	FLT53PH	3 phase fault on the Maryville (541251) to AECI Maryville (96097) 161kV line, near Maryville. a. Apply fault at the Maryville. b. Clear fault after 5 cycles by tripping the line from Maryville- AECI Maryville 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	FLT61PH	*Single phase fault and sequence like Cont. No.5*
7	FLT73PH	3 phase fault on the Maryville (541251) to Wind Farm (63826) 161kV line, near Maryville. a. Apply fault at Maryville. b. Clear fault after 5 cycles by tripping the line from Maryville-Wind Farm 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	FLT81PH	*Single phase fault and sequence like Cont. No.7*
9	FLT93PH	3 phase fault on the AECI Maryville (96097) to AECI Nodaway (96104) 161kV line, near AECI Maryville. a. Apply fault at the AECI Maryville. b. Clear fault after 5 cycles by tripping the line from AECI Maryville- Nodaway 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	FLT101PH	*Single phase fault and sequence like Cont. No.9*
11	FLT113PH	3 phase fault on the AECI Maryville (96097) to Creston (66560) 161kV line, near AECI Maryville. a. Apply fault at the AECI Maryville. b. Clear fault after 5 cycles by tripping the line from AECI Maryville- Creston 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	FLT121PH	*Single phase fault and sequence like Cont. No.11*
13	FLT133PH	3 phase fault on the Midway (#541252) – St. Joseph (541253) 161kV line, near the Midway. a. Apply fault at the Midway. b. Clear fault after 5 cycles by tripping the line from the Midway – St. Joe 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	FLT141PH	*Single phase fault and sequence like Cont. No.13*
15	FLT153PH	3 phase fault on a St. Joe 345/161kV autotransformer a. Apply fault at St. Joe 345kV (#541199). b. Clear fault after 5 cycles by tripping the auto c. no recluse
16	FLT161PH	*Single phase fault and sequence like Cont. No.15*
17	FLT173PH	3 phase fault on the Fairport – Gentry wind farm(96073) 161kV bus at Fairport (96076) a. Apply fault at Fairport (#96076). b. Clear fault after 5 cycles b tripping the line from Fairport to Gentry 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	FLT181PH	*Single phase fault and sequence like Cont. No.17*

Single line to ground faults were simulated in a manner consistent with currently accepted practices, that is to assume that a single line to ground will cause an approximate voltage drop at the fault location of 60% of nominal.

Areas monitored: AECI, WERE, MIPU, KACP, MEC, NPPD

Prior queued projects monitored:

a. GEN-2006-014 – 300MW of GE turbines at Maryville substation
b. GEN-2006-017 – 300MW of Clipper turbines at Maryville substation
c. AECI queue wind farm – 400MW of GE turbines on the Cooper – Fairport 345kV line
d. AECI queue wind farm – 400MW of Gamesa turbines on the Cooper – Fairport 345kV line.

3.1. Stability Criteria

Disturbances including three-phase and single-phase to ground faults should not cause synchronous and asynchronous plants to become unstable or disconnect from the transmission grid.

The criterion for synchronous generator stability as defined by NERC is:

"Power system stability is defined as that condition in which the difference of the angular positions of synchronous machine rotor becomes constant following an aperiodic system disturbance."

Voltage magnitudes and frequencies at terminals of asynchronous generators should not exceed magnitudes and durations that will cause protection elements to operate. Furthermore, the response after the disturbance needs to be studied at the terminals of the machine to insure that there are no sustained oscillations in power output, speed, frequency, etc.

Voltage magnitudes and angles after the disturbance should settle to a constant and reasonable operating level. Frequencies should settle to the nominal 60 Hz power frequency.

3.2. Modeling of Wind Turbine Generators in Dynamics

The GE 1.5 MW turbine is part of the PSS/E Wind standard library model. PSS/E Wind package issue 2.0.0 dated February 2006 was used for the dynamic stability analysis. Low voltage ride through was evaluated with the voltage and frequency protection settings summarized in Table 3.

Table 3: GE 1.5 MW wind turbine generator trip settings

<table>
<tr><th>Relay type</th><th>Description</th><th>Trip setting and time delay</th><th>Units</th></tr>
<tr><td rowspan="2">Undervoltage (27-1)</td><td>Relay trips if |Vbus|<</td><td>0.85</td><td>Pu</td></tr>
<tr><td>for t =</td><td>10.0</td><td>S</td></tr>
<tr><td rowspan="2">Undervoltage (27-2)</td><td>Relay trips if |Vbus|<</td><td>0.75</td><td>Pu</td></tr>
<tr><td>for t =</td><td>1.0</td><td>S</td></tr>
<tr><td rowspan="2">Undervoltage (27-3)</td><td>Relay trips if |Vbus|<</td><td>0.70</td><td>Pu</td></tr>
<tr><td>for t =</td><td>0.625</td><td>S</td></tr>
<tr><td rowspan="2">Undervoltage (27-4)</td><td>Relay trips if |Vbus|<</td><td>0.15</td><td>Pu</td></tr>
<tr><td>for t =</td><td>0.625</td><td>S</td></tr>
<tr><td rowspan="2">Overvoltage (59-1)</td><td>Relay trips if |Vbus|></td><td>1.1</td><td>Pu</td></tr>
<tr><td>for t =</td><td>1.0</td><td>S</td></tr>
<tr><td rowspan="2">Overvoltage (59-2)</td><td>Relay trips if |Vbus|></td><td>1.15</td><td>Pu</td></tr>
<tr><td>for t =</td><td>0.1</td><td>S</td></tr>
<tr><td rowspan="2">Overvoltage (59-3)</td><td>Relay trips if |Vbus|></td><td>1.3</td><td>Pu</td></tr>
<tr><td>for t =</td><td>0.02</td><td>S</td></tr>
<tr><td rowspan="2">Underfrequency (81U-1)</td><td>Relay trips if Fbus <</td><td>57.5</td><td>Hz</td></tr>
<tr><td>for t =</td><td>10.0</td><td>S</td></tr>
<tr><td rowspan="2">Underfrequency (81U-2)</td><td>Relay trips if Fbus <</td><td>56.5</td><td>Hz</td></tr>
<tr><td>for t =</td><td>0.02</td><td>S</td></tr>
<tr><td rowspan="2">Overfrequency (81O-1)</td><td>Relay trips if Fbus ></td><td>61.5</td><td>Hz</td></tr>
<tr><td>for t =</td><td>30.0</td><td>S</td></tr>
<tr><td rowspan="2">Overfrequency (81U-2)</td><td>Relay trips if Fbus ></td><td>62.5</td><td>Hz</td></tr>
<tr><td>for t =</td><td>0.02</td><td>S</td></tr>
</table>

3.3. Pre-Project Dynamic Simulations

Non-disturbance runs of 10 seconds were carried out on Winter Peak 2008 and Summer Peak 2008 base cases to verify proper initialization of dynamic models and to check steady-state conditions.

PSS/E version 30.2.1 was used for dynamic stability studies.

Nearby areas are stable for the fault contingencies in Table 2 in winter 2008 and summer 2008 peak cases. Results are summarized on Table 4.

3.4 Post-Project Dynamic Simulations

Non-disturbance runs of 10 seconds were carried out on Winter Peak 2008 and Summer Peak 2008 base cases to verify proper initialization of dynamic models and valid power flow cases after the addition of the project.

Nearby areas are stable for the fault contingencies in Table 2 in winter 2008 and summer 2008 peak cases. Results are summarized on Table 4.

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Table 4: Summary of stability analysis results

Fault No.	*Description*	Winter Peak 2008		Summer Peak 2008	
		Pre-project	Post-project	Pre-project	Post-project
1	3 phase fault on the Wind Farm Station (#89572) - Maryville (#541251) 161kV line, near the wind farm.	STABLE	STABLE	STABLE	STABLE
2	*Single phase fault and sequence like Cont. No. 1*	STABLE	STABLE	STABLE	STABLE
3	3 phase fault on the Wind Farm (#89572) - Midway (541252) 161kV line, near the wind farm.	STABLE	STABLE	STABLE	STABLE
4	*Single phase fault and sequence like Cont. No.3*	STABLE	STABLE	STABLE	STABLE
5	3 phase fault on the Maryville (541251) to AECI Maryville (96097) 161kV line, near Maryville.	STABLE	STABLE	STABLE	STABLE
6	*Single phase fault and sequence like Cont. No.5*	STABLE	STABLE	STABLE	STABLE
9	3 phase fault on the Maryville (541251) to Wind Farm (63826) 161kV line, near Maryville.	STABLE	STABLE	STABLE	STABLE

Fault No.	*Description*	Winter Peak 2008		Summer Peak 2008	
		Pre-project	Post-project	Pre-project	Post-project
10	*Single phase fault and sequence like Cont. No.7*	STABLE	STABLE	STABLE	STABLE
11	3 phase fault on the AECI Maryville (96097) to AECI Nodaway (96104) 161kV line, near AECI Maryville.	STABLE	STABLE	STABLE	STABLE
12	*Single phase fault and sequence like Cont. No.9*	STABLE	STABLE	STABLE	STABLE
13	3 phase fault on the AECI Maryville (96097) to Creston (66560) 161kV line, near AECI Maryville.	STABLE	STABLE	STABLE	STABLE
14	*Single phase fault and sequence like Cont. No.11*	STABLE	STABLE	STABLE	STABLE

Fault No.	*Description*	Winter Peak 2008		Summer Peak 2008	
		Pre-project	Post-project	Pre-project	Post-project
15	3 phase fault on the Midway (#541252) – St. Joseph (541253) 161kV line, near the Midway.	STABLE	STABLE	STABLE	STABLE
16	*Single phase fault and sequence like Cont. No.13*	STABLE	STABLE	STABLE	STABLE
17	3 phase fault on a St. Joe 345/161kV autotransformer	STABLE	STABLE	STABLE	STABLE
18	*Single phase fault and sequence like Cont. No.15*	STABLE	STABLE	STABLE	STABLE

APPENDIX A

COLLECTOR IMPEDANCE CALCULATIONS

APPENDIX B

DYNAMIC STABILITY PLOTS – POST PROJECT

WINTER PEAK 2008

Flat run
and
Fault contingencies #1 thru #18

SUMMER PEAK 2008

Flat run
and
Fault contingencies #1 thru #18