Southwest Power Pool

Impact Study for Generation Interconnection Request GEN–2007–003

SPP Tariff Studies
(#GEN-2007-003)

May 2008

Summary

Pursuant to the tariff and at the request of the Southwest Power Pool (SPP), S&C Electric Company (S&C) performed the following Impact Study to satisfy the Impact Study Agreement executed by the requesting customer and SPP for SPP Generation Interconnection request GEN-2007-003. The request for interconnection was laced with SPP in accordance SPP's Open Access Transmission Tariff, which covers new generation interconnections on SPP's transmission system.

Due to the machine parameters provided by the Customer to SPP for this Impact Study, the queue position for this Interconnection Request has been lowered from 30 MW to 20 MW.

Interconnection Facilities

The total minimum cost for adding a new breaker and terminating the transmission line serving GEN-2007-003 facilities is estimated at $497,594. This cost is listed in Table 1. This cost does not include building the Customer's 115 kV transmission line extending from the point of interconnection to serve its 115/12.47 kV switching facilities. This cost also does not include the Customer's 115/12.47 kV switching substation, all of which should be determined by the Customer. The Customer is responsible for these 115 – 12.47 kV facilities up to the point of interconnection. Network constraints in the local transmission systems that were identified are shown in Table 3.

TABLE 1: Direct Assignment Facilities

OWNER	REQUIRED FACILITY	ESTIMATED COST (2007 DOLLARS)
CUSTOMER	(1) 115/12.47 kV Customer switching facilities.	*
CUSTOMER	(1) 115 kV transmission line from Customer switching facilities to the City of Goodland substation.	*
CUSTOMER	Right-of-Way for all Customer facilities.	*
CITY OF GOODLAND	(1) 115 kV breaker and line terminal for GEN-2007-003 at the City of Goodland substation.	$497,594
	TOTAL	*****

* *Estimates of cost to be determined.*

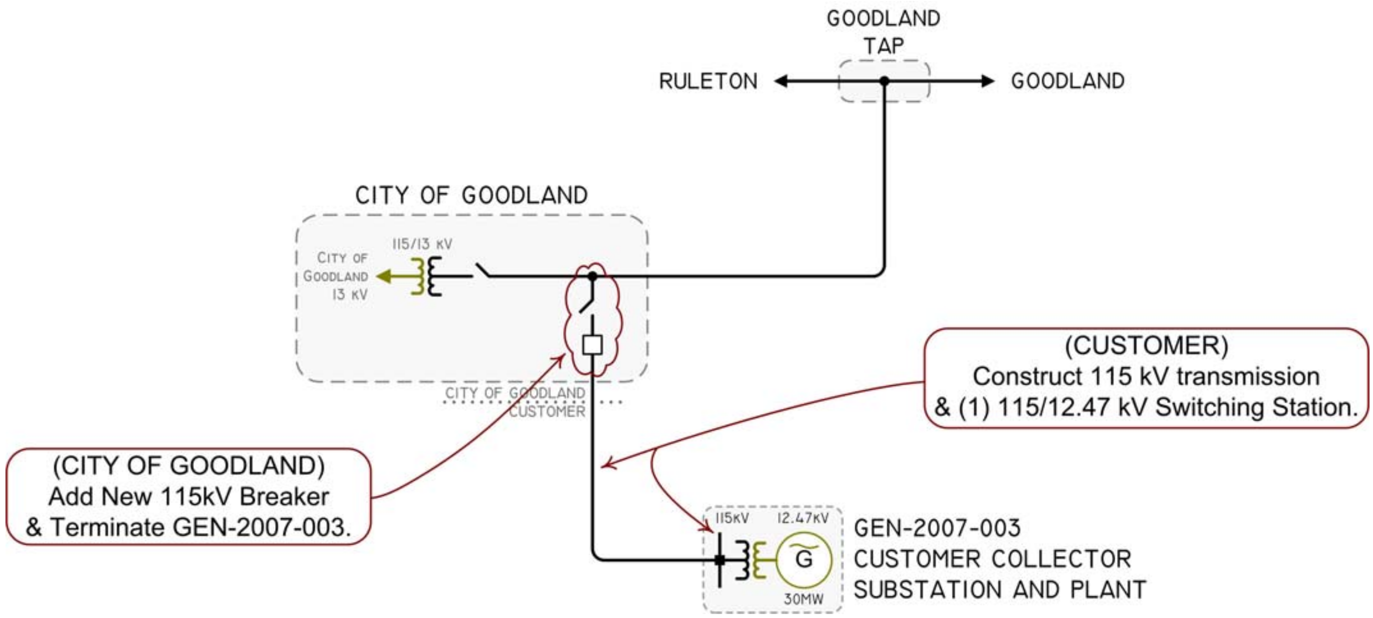

FIGURE 1: Proposed Method of Interconnection
(Final design to be determined)

Final Report

For

Southwest Power Pool

From

S&C Electric Company

IMPACT STUDY FOR GENERATION INTERCONNECTION REQUEST GEN-2007-003

S&C Project No. 2774

May 7, 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 for a 20 MW coal fired steam turbine in Sherman County, Kansas. The project will be interconnected into Sunflower Electric Power Corp (SUNC) near the existing City of Goodland substation through a step up transformer and breaker. The objective of this study is to determine the impact of the interconnection on the stability of nearby areas and prior queued projects during winter peak (with facilities planned for 2008) and summer peak (with facilities planned for 2012).

Generator and excitation system parameters used for the study were provided by the customer or assumed for typical generators for similar generator vintage and construction. Specifications of the interconnecting generator are not available and should be determined through generator testing. Testing results should be compared against the assumptions made for this study to weight the need for a re-study.

Steady-state and dynamic studies were performed at full load. Three-phase and single-phase-to-ground faults were studied at locations specified by SPP. Results show that nearby areas remain stable for most fault contingencies. Fault contingencies that are unstable with the project are also unstable without the project.

Without and with the interconnecting project, permanent three-phase faults on the Setab to City Service 115 kV line can cause a number of wind turbine generators within GEN-2001-039M to trip off on overvoltage relay protection. However, provided that fixed taps of pad mounted transformers of turbines that disconnect are changed to 36.23 kV (currently flat), the wind farm will survive the fault contingency. Alternatively, the fixed tap of the main 34.5/115 kV step up transformer could be set to 120.75 kV (currently set flat).

Study results without and with the interconnecting project indicate that permanent three-phase or single-line to ground faults on the Mingo to Setab 345 kV transmission line can cause the 400MW, GEN-2006-049 wind farm on the Potter-Finney 345 kV line in the SPS controlled area to become unstable. This instability scenario has been studied separately in the Impact Study for GEN-2006-049.

1. Introduction

This system impact study was performed in response to a generation interconnection study request for a 20 MW coal fired steam turbine in Sherman County, Kansas. The generator was previously used by the City of Moorhead, Minnesota, but recently changed ownership. The project will be interconnected into Sunflower Electric Power Corp (SUNC) near the existing City of Goodland substation through a step up transformer and breaker.

The objective of this study is to determine the impact of the interconnection on the stability of nearby areas and prior queued projects during winter peak (with facilities planned for 2008) and summer peak (with facilities planned for 2012).

2. Load Flow Model

The project was added to the winter peak 2008 and summer peak 2012 seasonal base load flow cases. The Brown Boveri steam turbine will interconnect to the 115 kV transmission system through a step up transformer and breaker. The interconnecting customer will operate the plant at 23.529 MVA rated output at 0.5 psig H_2 pressure. The details modeled in the base load flow cases are summarized on Table 1. Figure 1 shows the project interconnection as well as nearby buses.

Table 1: Power flow model parameters for GEN-2007-003

Feeder 1	Parameters
One (1) Brown-Boveri generator at 12.47 kV	20 MW 23.529 MVA Power factor at 12.47 kV bus: 0.85
One (1) GSU 12.47 / 115 kV transformer	25 MVA % IZ = 12

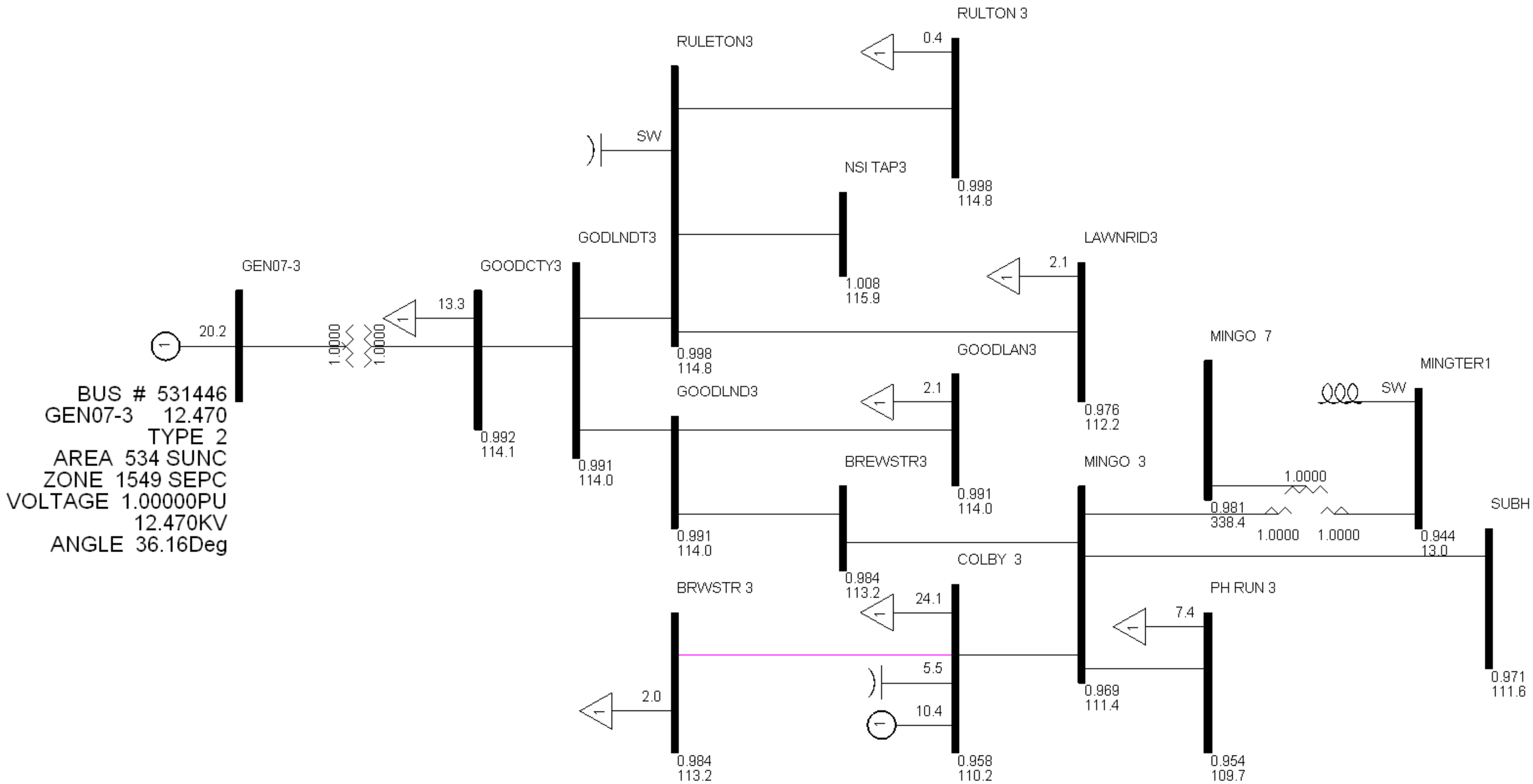

Figure 1: GEN-2007-003 and nearby buses (summer peak 2012)

3. Dynamic Stability Analysis

Dynamic simulations were performed for fault contingencies in Table 2 with and without GEN-2007-003.

Table 2: Fault Contingencies Evaluated

Cont. No.	*Cont. Name*	*Description*
1	*FLT13PH*	3 phase fault on the Goodland Tap (531443) to Ruleton (531357) 115kV line, near Goodland Tap. a. Apply fault at Goodland Tap. b. Clear fault after 5 cycles by tripping the line from Goodland Tap to Ruleton. 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 Goodland Tap (531443) to Sunflower Goodland (531353) 115kV line, near Goodland Tap. a. Apply fault at Goodland Tap. b. Clear fault after 5 cycles by tripping the line from Goodland Tap to Sunflower Goodland. 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 Ruleton (531357) to Lawn Ridge (531368) 115kV line, near Ruleton. a. Apply fault at Ruleton. b. Clear fault after 5 cycles by tripping the line from Ruleton to Lawn Ridge. 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 G06-34 Sub (90800) to Sharon Springs (531358) 115kV line, near Sharon Springs. a. Apply fault at Sharon Springs. b. Clear fault after 5 cycles by tripping the line from G06-34 to Sharon Springs. 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 Tribune Switch (531438) to Selkirk (531434) 115kV line, near Tribune Switch. a. Apply fault at Tribune Switch. b. Clear fault after 5 cycles by tripping the line from Tribune Switch to Selkirk. 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 Setab (531464) to City Service (531416) 115kV line, near Setab. a. Apply fault at Setab. b. Clear fault after 5 cycles by tripping the line from Setab to Cities Service. 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.119*
13	FLT133PH	3 phase fault on Setab (531464) to Scot City (531433) 115kV line, near Setab. a. Apply fault at Setab. b. Clear fault after 5 cycles by tripping the line from Setab to Scott City. 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 the Setab autotransformer (531465-531464-531259) a. Apply fault at the Setab 345kV bus. b. Clear fault after 5 cycles by taking the auto out of service
16	FLT161PH	*Single phase fault and sequence like Cont. No.15*
17	FLT173PH	3 phase fault on the Mingo autotransformer (531451-531429-531452) a. Apply fault at the Mingo 345kV bus. b. Clear fault after 5 cycles by taking the auto out of service
18	FLT181PH	*Single phase fault and sequence like Cont. No.17*
19	FLT193PH	3 phase fault on Mingo (531451) to Setab (531465) 345kV line, near Setab. a. Apply fault at Setab. b. Clear fault after 5 cycles by tripping the line from Setab to Mingo. c. no recluse
20	FLT201PH	*Single phase fault and sequence like Cont. No.19*
21	FLT213PH	3 phase fault on Atwood Switch (531364) to Herndon (531367) 115kV line, near Atwood Switch. a. Apply fault at Atwood Switch. b. Clear fault after 5 cycles by tripping the line from Setab to Cities Service. 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	FLT221PH	*Single phase fault and sequence like Cont. No.21*

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 a voltage drop at the fault location of 60% of nominal.

Areas monitored: SUNC, MIDW, WEPL, WERE, XEL

Prior queued projects monitored:

GEN-2001-039M; 99MW of Vestas V90 turbines on the Selkirk-Setab 115kV line
GEN-2006-034; 84MW of GE turbines on the Ruleton – Tribune 115kV line
GEN-2006-040; 108MW of Suzlon turbine at Mingo 115kV
GEN-2006-032; 200MW of Gamesa turbines at South Hays 230kV
GEN-2003-013; 196MW of GE turbines on the Potter-Finney 345kV line
GEN-2006-049; 400MW of Suzlon turbines on the Potter-Finney 345kV line
Sunflower prior queued 600MW coal unit at Holcomb 345kV

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. Dynamic Model

The generator was modeled as a round rotor with quadratic saturation using PSS/E 30.2.1 library model GENROU. The parameters used are listed in Table 3.

Table 3: Generator parameters

Description	Value
Machine base	23.529 MVA
Open circuit transient field time constant (direct axis)	0.620 seconds
Open circuit subtransient field time constant (direct axis)	0.027 seconds
Open circuit transient field time constant (quadrature axis)	0.410 seconds
Open circuit subtransient field time constant (quadrature axis)	0.620 seconds
Inertia constant	4.130 pu
Speed damping	1.164 pu
Synchronous reactance (direct axis)	1.700 pu
Synchronous reactance (quadrature axis)	1.620 pu
Transient reactance (direct axis)	0.256 pu
Transient reactance (quadrature axis)	0.500 pu (assumed)
Subtransient reactance (direct and quadrature axis)	0.185 pu
Saturation at 1.0 pu voltage	0.100 (assumed)
Saturation at 1.2 pu voltage	0.430

Assumed parameters are based on "typical" and were proposed by S&C and approved by SPP. The information received from the interconnecting customer was not available.

The excitation system was modeled as an IEEE Type ST1A using PSS/E library model ESST1A. The parameters used are listed in Table 4.

Table 4: Excitation system parameters

Description	Value
Alternate UEL inputs	1
Alternate stabilizer inputs	1
Terminal voltage transducer time constant	0.02 seconds
AVR upper limit	0.20 pu
AVR lower limit	-0.20 pu
AVR lead time constant (TC)	1.00 seconds
AVR lag time constant (TB)	1.00 seconds
AVR lead time constant (TC1)	0.00 seconds
AVR lag time constant (TB1)	0.00 seconds
AVR gain	210.0 pu
AVR time constant	0.0 seconds
Positive regulator output limit	310 pu
Negative regulator output limit	-310 pu
Positive exciter output limit	6.43 pu
Negative exciter output limit	-6.0 pu
Rectifier regulation	0.038 pu
Exciter feedback gain	0.0 pu
Exciter feedback time constant	1.0 seconds
Field current limiter gain	4.54 pu
Field current limiter setting	4.4 pu

3.3. Wind Turbine Modeling Issues

The Suzlon S88-2.1 MW/60 Hz wind turbine model used for GEN-2006-040 and GEN-2006-049 will add "chatter" and oscillations to the real, reactive power, and speed when terminal voltages are around 0.90 pu. This is presumably due to lack of reactive power required to keep the generator terminal voltage above 0.90 pu. Suzlon wind turbine undervoltage relaying begins timing to trip when the voltage drops below 0.90 pu. The chatter can also be a modeling issue. This was noticed primarily when running fault contingencies #19 and #20.

3.4. Pre-Project Dynamic Simulations

Non-disturbance runs of 10 seconds were carried out on Winter Peak 2008 and Summer Peak 2012 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.

Winter Peak 2008

All fault contingencies are stable with few exceptions:

As a result of fault #11, a number of wind turbines belonging to GEN-2001-039M will trip offline on overvoltage relay actuation. Wind turbines connected to the following buses will disconnect: #645 (GFRT30), #646 (GFRT29), #639 (GONT18), #630 (GTWT09), #640 (GONT15), #641 (GONT14), #631 (GTWT06), and #632 (GTWT05). Simulations show that if the fixed tap of each of the pad mount transformers of turbines that disconnect were set to 36.23 kV (currently set flat), the wind farm would survive the fault contingency. Alternatively, the fixed tap of the main 34.5/115 kV step up transformer could be set to 120.75 kV (currently set flat) and the wind farm would survive the fault contingency.

Faults #19 and #20 cause the output power, frequency, and speed of Suzlon wind turbine generators belonging to GEN-2006-049 to "chatter" and oscillate post-fault when terminal voltages settle near 0.90 pu. Simulations show that if the fixed taps in each of the 34.5/115 kV transformers (GEN-2006-049) were set flat (currently 2.5% above), the oscillations will damp out. GEN-2006-049 is located on the southern edge of the study area for GEN-2007-003 and does not directly affect the study project. The issues concerning GEN-2006-049 are discussed further in the Impact Study for GEN-2006-049.

Pre-project study results are summarized in Table 5 for fault contingencies in Table 2.

Summer Peak 2012

All fault contingencies are stable with exception of fault #19, and #20, which cause the output power, frequency, and speed of Suzlon wind turbine generators belonging to GEN-2007-049 to "chatter" and oscillate. As mentioned previously, if the fixed taps in each of the 115/34.5 kV transformers (GEN-2006-049) were set flat, the output from the Suzlon turbines would not oscillate. Only for summer peak loads, additional static compensation is required at GEN-2006-049. An additional 55 MVAR MSSC (mechanically switched shunt capacitor bank) would come online at the 115 kV POI (MSS-44 bus #700) for voltage support. Alternatively, the MSSC can be installed at the 34.5 kV collector bus. The output from the Suzlon turbines will not oscillate with the fixed tap adjustments and additional 55 MVAR MSSC. GEN-2006-049 is located on the southern edge of the study area for GEN-2007-003 and does not directly affect the study project. The issues concerning GEN-2006-049 are discussed further in the Impact Study for GEN-2006-049.

Pre-project study results are summarized in Table 5 for fault contingencies listed in Table 2.

3.5 Post-Project Dynamic Simulations

Non-disturbance runs of 10 seconds were carried out on Winter Peak 2008 and Summer Peak 2012 base cases to verify proper initialization of dynamic models and valid power flow cases after the addition of the project.

Winter Peak 2008

All fault contingencies are stable with few exceptions:

Wind turbines connected to bus #645 (GFRT30) and #646 (GFRT29) will disconnect after fault #11. As with the pre-project case, if the fixed tap of each of the pad mount transformers of turbines that disconnect were set to 36.23 kV (currently set flat), the wind farm would survive the fault contingency. Alternatively, the fixed tap of the main 34.5/115 kV step up transformer could be set to 120.75 kV (currently set flat) and the wind farm would survive the fault contingency.

Faults #19 and #20 cause the output power, frequency, and speed of Suzlon wind turbine generators belonging to GEN-2006-049 to “chatter” and oscillate post-fault when terminal voltages settle near 0.90 pu. As with the pre-project case, if the fixed taps in each of the 115/34.5 kV transformers (GEN-2006-049) were set flat (currently 2.5% above), the oscillations will damp out.

Pre-project study results are summarized in Table 5 for fault contingencies listed in Table 2.

Summer Peak 2012

All fault contingencies are stable with exception of fault #19, and #20, which cause the output power, frequency, and speed of Suzlon wind turbine generators belonging to GEN-2006-049 to “chatter” and oscillate. As mentioned previously, the fixed taps in each of the 115/34.5 kV transformers (GEN-2006-049) could set flat. An additional 55 MVAR MSSC (mechanically switched shunt capacitor bank) would come online at the 115 kV POI (MSS-44 bus #700) for voltage support. Alternatively, the MSSC can be installed at the 34.5 kV collector bus. The oscillations from the Suzlon turbines will damp out with the fixed tap adjustments and additional 55 MVAR MSSC.

Post-project study results are summarized in Table 5 for fault contingencies listed in Table 2.

Table 5: Summary of Fault Simulation Results

Fault No.	*Description*	Winter Peak 2008			Summer Peak 2012		
		Pre-project	Post-project		Pre-project	Post-project	
			No changes	with fixed tap adjustments[1]		No changes	with fixed tap adjustments and MSSC[2]
1	3 phase fault on the Goodland Tap (531443) to Ruleton (531357) 115kV line, near Goodland Tap.	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE
2	*Single phase fault and sequence like Cont. No. 1*	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE
3	3 phase fault on the Goodland Tap (531443) to Sunflower Goodland (531353) 115kV line, near Goodland Tap.	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE
4	*Single phase fault and sequence like Cont. No. 3*	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE
5	3 phase fault on the Ruleton (531357) to Lawn Ridge (531368) 115kV line, near Ruleton.	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE
6	*Single phase fault and sequence like Cont. No. 5*	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE

Fault No.	Description	Winter Peak 2008			Summer Peak 2012		
		Pre-project	Post-project		Pre-project	Post-project	
			No changes	with fixed tap adjustments[1]		No changes	with fixed tap adjustments and MSSC[2]
7	3 phase fault on the G06-34 Sub (90800) to Sharon Springs (531358) 115kV line, near Sharon Springs.	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE
8	*Single phase fault and sequence like Cont. No. 7*	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE
9	3 phase fault on Tribune Switch (531438) to Selkirk (531434) 115kV line, near Tribune Switch.	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE
10	*Single phase fault and sequence like Cont. No.9*	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE

Fault No.	*Description*	Winter Peak 2008			Summer Peak 2012		
			Post-project			Post-project	
		Pre-project	No changes	with fixed tap adjustments[1]	Pre-project	No changes	with fixed tap adjustments and MSSC[2]
11	3 phase fault on Setab (531464) to City Service (531416) 115kV line, near Setab.	UNSTABLE GEN-2001-039M trip	UNSTABLE GEN-2001-039M trip	STABLE	STABLE	STABLE	STABLE
12	*Single phase fault and sequence like Cont. No.119*	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE
13	3 phase fault on Setab (531464) to Scot City (531433) 115kV line, near Setab.	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE
14	*Single phase fault and sequence like Cont. No.13*	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE
15	3 phase fault on the Setab autotransformer (531465-531464-531259)	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE
16	*Single phase fault and sequence like Cont. No.15*	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE

Fault No.	*Description*	Winter Peak 2008			Summer Peak 2012		
		Pre-project	Post-project		Pre-project	Post-project	
			No changes	with fixed tap adjustments[1]		No changes	with fixed tap adjustments and MSSC[2]
17	3 phase fault on the Mingo autotransformer (531451-531429-531452)	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE
18	*Single phase fault and sequence like Cont. No.17*	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE
19	3 phase fault on Mingo (531451) to Setab (531465) 345kV line, near Setab.	UNSTABLE: GEN-2006-049	UNSTABLE: GEN-2006-049	STABLE	UNSTABLE: GEN-2006-049	UNSTABLE: GEN-2006-049	STABLE
20	*Single phase fault and sequence like Cont. No.19*	UNSTABLE: GEN-2006-049	UNSTABLE: GEN-2006-049	STABLE	UNSTABLE: GEN-2006-049	UNSTABLE: GEN-2006-049	STABLE
21	3 phase fault on Atwood Switch (531364) to Herndon (531367) 115kV line, near Atwood Switch.	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE
22	*Single phase fault and sequence like Cont. No.21*	STABLE	STABLE	STABLE	STABLE	STABLE	STABLE

Notes:
1. Fixed tap adjustments on GEN-2001-039M pad mount transformers and GEN-2006-49 main step up transformers
2. Fixed tap adjustments on GEN-2001-039M pad mount transformers and GEN-2006-49 main step up transformers and 55 MVAR MSSC online at 115 kV MSS-44

4. Conclusions

During winter and summer peak conditions, all fault contingencies are stable with the exception of fault #19 and #20. During winter peak, GEN-2001-039M will disconnect for fault #11. These problems are not the result of interconnecting the project as they are present in the pre-project case as well. The proposed solution is to adjust the fixed tap settings of transformers in GEN-2001-039M and GEN-2006-049. During summer peak conditions, additional static compensation is required at GEN-2006-049. This additional MSCC can be installed at the 115 kV POI or 34.5 kV collector bus for voltage support. A 55 MVAR MSSC is required if installed at the 115 kV POI.

APPENDIX A

DYNAMIC STABILITY PLOTS

WINTER PEAK 2008

(FAULT CONTINGENCIES #1 THRU #22)

SUMMER PEAK 2012

(FAULT CONTINGENCIES #1 THRU #22)

APPENDIX B

DYNAMIC STABILITY PLOTS

WITH IMPROVEMENTS

WINTER PEAK 2008

WITH FIXED TAP ADJUSTMENTS AT GEN-2006-049 AND GEN-2001-039M

(FAULT CONTINGENCIES #11, #19, AND #20)

SUMMER PEAK 2012

WITH FIXED TAP ADJUSTMENTS AT GEN-2006-049 AND GEN-2001-039M

55 MVAR MSSC ONLINE AT GEN-2006-049

(FAULT CONTINGENCIES #11, #19, AND #20)