Southwest Power Pool

Interim Operational Impact Study For Generation Interconnection Request GEN-2008-079

SPP Tariff Studies

(#GEN-2008-079)

October *2010*

Executive Summary

<OMITTED TEXT> (Customer) has requested an Impact Study under the Southwest Power Pool Open Access Transmission Tariff (OATT) for interconnection of 99.5 MW of wind generation within the balancing authority of Sunflower Electic Power Corporation (SUNC) in Gray County, Kansas. SPP expects to complete the Interconnection Agreement as part of the cluster study DISIS-2009-001. SPP may not be able submit an Interconnection Agreement in time for the Customer's requested in-service date of December 1, 2010. Therefore, Customer has requested this Interim Operation Impact Study (IOIS) to determine the impacts of interconnecting its generating facility to the transmission system before all required studies can be completed and all required Network Upgrades identified in the DISIS-2009-001 posted on January 30, 2010 can be placed into service. Interim Operational Impact Studies are conducted under GIP Section 11A of the SPP OATT.

This study is intended only as an Interim Operation Study that will be used in order to tender an Interim Interconnection Agreement to the Customer for Interim Interconnection Service. If an Interim Interconnection Agreement is not executed with the Customer, this study will be inapplicable. If an Interim Interconnection Agreement is executed with the Customer, this study will be considered inapplicable upon termination of such Interim Interconnection Agreement.

This study assumed that only the higher queued projects identified in Table 3 of this study might go into service before the completion of all Network Upgrades identified in DISIS-2009-001. If any additional generation projects not identified in Table 3 but with queue priority equal to or over GEN-2008-079 request to go into commercial operation before all Network Upgrades identified through the DISIS-2009-001 study process as required, then this study must be conducted again to determine whether sufficient interim interconnection capacity exists to interconnect the GEN-2008-079 interconnection request in addition to all higher priority requests in operation or pending operation. These projects are listed in Table 4. This will also be a requirement of a Final GIA the customer signs until such time that all network upgrades are placed in service.

A power flow analysis showed that the maximum power that the Customer's wind facility can inject into the SUNC transmission system is 65.5 MW due to line capacity of the Cudahay - Kismet 115kV transmission line. Powerflow analysis was based on both summer and winter peak conditions and light loading cases.

A power factor analysis at the point of interconnection (POI) determined that the Customer's wind facility must be capable of meeting 0.99 lagging and 0.96 leading power factor at the POI. The stability study results show that with the Customer facility the transmission system remains stable for all simulated contingencies and conditions studied. If the Customer does not use the GE 1.5 MW and GE 1.6 MW wind turbines this IOIS will be considered invalid and the Customer will not be allowed to interconnect on an interim basis.

The wind generation facility was studied with forty-five (45) General Electric 1.5 MW wind turbine generators and twenty (20) General Electric 1.6 MW wind turbine generators. This Impact study addresses the dynamic stability effects of interconnecting the plant to the rest of the SUNC transmission system for the system condition as it will be on December 1, 2010. Two seasonal base cases were used in the study to analyze the stability impacts of the proposed generation facility. The cases studied were modified 2010 summer peak and 2010 winter peak cases that were adjusted to reflect system conditions at the requested in-service date. Each case was modified to include prior queued projects that are listed in the body of the report. Thirty-six (36) contingencies were identified for use in this study. The GE 1.5MW and 1.6 MW wind turbines were modeled using information provided by the Customer.

The costs for network upgrades and the interconnection facilities for interim operation are estimated to be $3,267,000. The Customer will also be required to provide security in the amount of $12,000,000 per the Facility Study for GEN-2008-079. This amount of security will be adjusted as the GEN-2008-079 interconnection request advances through the Cluster interconnection process as stated in SPP's OASIS posting.

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.

1.0 Introduction

<OMITTED TEXT> (Customer) has requested an Impact Study under the Southwest Power Pool Open Access Transmission Tariff (OATT) for interconnection of 99.5 MW of wind generation within the balancing authority of Sunflower Electric Power Corporation (SUNC) in Gray County, Kansas. SPP expects to complete the Interconnection Agreement as part of the cluster study DISIS-2009-001. SPP may not be able to complete all interconnection studies required under the OATT in time for the Customer's requested in-service date of December 1, 2010. Therefore, Customer has requested this Interim Operation Impact Study (IOIS) to determine the impacts of interconnecting its generating facility to the transmission system before all required studies can be completed and all required Network Upgrades identified in the DISIS-2009-001 posted on January 30, 2010 can be placed into service. Interim Operational Impact Studies are conducted under GIP Section 11A of the SPP OATT.

This Impact study addresses the dynamic stability effects of interconnecting the plant to the rest of the SUNC transmission system for the system condition as it will be on December 1, 2010. The wind generation facility was studied with forty-five (45) General Electric 1.5 MW wind turbine generators and twenty (20) General Electric 1.6 MW wind turbine generators. Two seasonal base cases were used in the study to analyze the stability impacts of the proposed generation facility. The cases studied were modified versions of the 2010 summer peak and 2010 winter peak to reflect the system conditions at the requested in-service date. Each case was modified to include prior queued projects that are listed in the body of the report. Thirty-six (36) contingencies were identified for this study.

2.0 Purpose

The purpose of this Interim Operational Impact Study (IOIS) is to evaluate the impact of the proposed interconnection on the reliability of the Transmission System. The IOIS considers the Base Case as well as all Generating Facilities (and with respect to (b) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the IOIS is commenced:

a) are directly interconnected to the Transmission System;
b) are interconnected to Affected Systems and may have an impact on the Interconnection Request;
c) have a pending higher queued Interconnection Request to interconnect to the Transmission System listed in Table 3; or
d) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC.

Any changes to these assumptions, for example, one or more of the previously queued projects not included in this study signing an interconnection agreement, may require a re-study of this request at the expense of the customer.

Nothing in this System Impact Study constitutes a request for transmission service or confers upon the Interconnection Customer any right to receive transmission service.

3.0 Facilities

3.1 Generating Facility

The project was modeled as two (2) equivalent wind turbine generators of 67.5 MW and 32 MW output. The wind turbines are each connected to an equivalent 0.69/34.5KV generator step unit (GSU) with respective ratings of 78.75 MVA with an impedance of 5.75% and 36 MVA with an impedance of 5.75%. The high side of each GSU is connected to the 34.5/115kV substation transformer. The substation transformer is rated 67.2/89.6/112 MVA with 8.5% impedance on the

67.2 MVA base. A 115kV transmission line connects the Customer's substation transformer to the POI.

3.2 Interconnection Facility

The Point of Interconnection will be at a tap on the Transmission Owners Cudahay – Judson Large 115kv transmission line. Figure 1 shows the proposed POI. Figure 2 shows the Point of Interconnection.

Cost to interconnect on an Interim basis is estimated at $3,267,000.

Customer's latest estimate for cost responsibility for Interconnection Service is given in DISIS-2009-001 at $15,267,000. The Customer will be required to provide security in the amount of $12,000,000 to move forward into an Interim Interconnection Agreement.

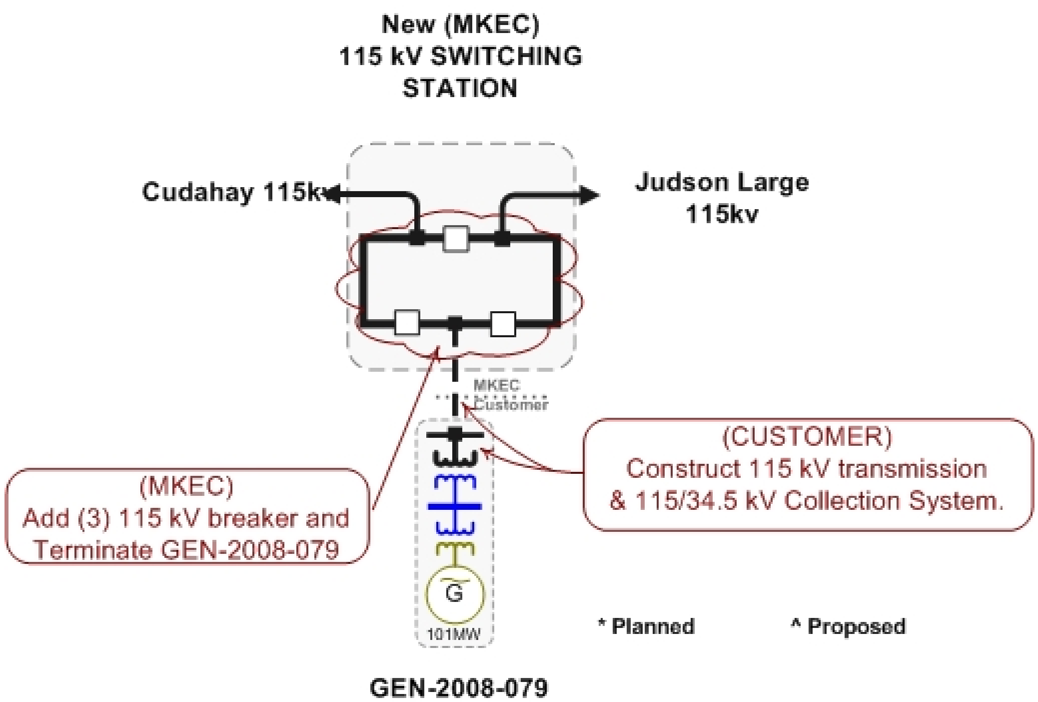

Figure 1: GEN-2008-079 Facility and Proposed Interconnection Configuration

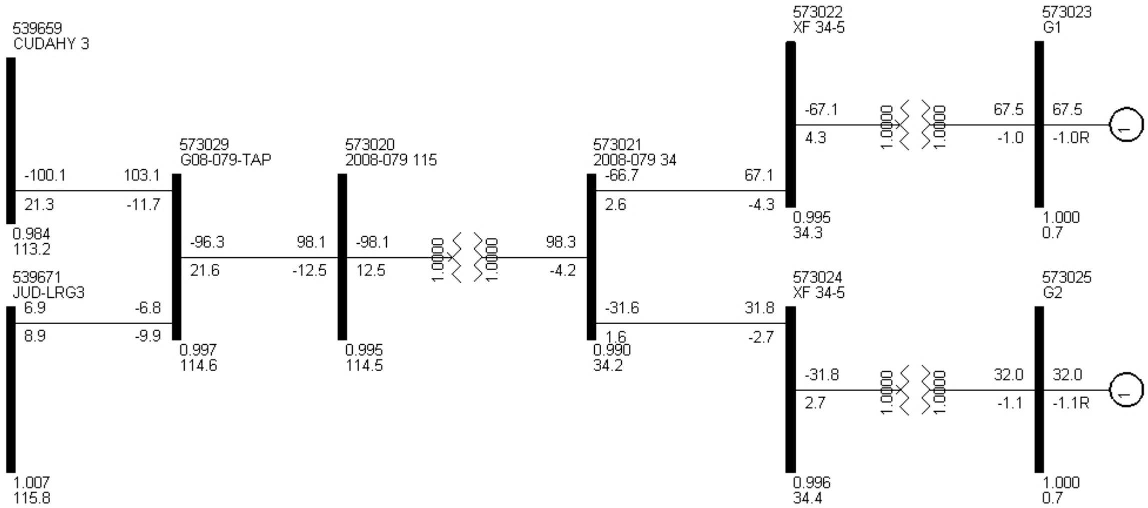

Figure 2: GEN-2008-079 Bus Interconnection

4.0 <u>Power Flow Analysis</u>

A powerflow analysis was conducted for the Interconnection Customer's facility using a modified version of the 2011 summer and 2011 winter seasonal models. The output of the Interconnection Customer's facility was offset in the model by a reduction in output of existing online SPP generation. This method allows the request to be studied as an Energy Resource (ERIS) Interconnection Request. This analysis was conducted assuming that previous queued requests listed in Table 3 were in-service.

The Southwest Power Pool (SPP) Criteria states that:

> "The transmission system of the SPP region shall be planned and constructed so that the contingencies as set forth in the Criteria will meet the applicable NERC Reliability Standards for transmission planning. All MDWG power flow models shall be tested to verify compliance with the System Performance Standards from NERC Table 1 – Category A."

The ACCC function of PSS/E was used to simulate single contingencies in portions of or all of the control area of SUNC and other control areas within SPP and the resulting data analyzed. This satisfies the "more probable" contingency testing criteria mandated by NERC and the SPP criteria.

Higher queued projects listed in Table 4. were not modeled as in service. If any of these come in service, this study will need to be performed again to determine if any interim interconnection service is available.

The ACCC analysis indicates that as a result of the Customer's project at full nameplate power the SUNC transmission system will experience thermal overloads as shown in Table 1. To mitigate these violations the maximum power output of Customer's project shall be limited to 65.5 MW for the interim operational interconnection.

Table 1: ACCC Analysis

SOURCE	GROUP DISPATCH SCENARIO	REQUESTED POWER (MW)	AVAILABLE INTERCON-NECTION (MW)	SEASON	DIRECTION	MONTCOMMONNAME	RATE A	RATE B	TDF	TC % LOADING	CONTNAME
G08_079	3	101	95.2	11WP	'TO->FROM'	CIMARRON RIVER TAP - KISMET 3 115KV CKT 1'	120.7	129.5	0.2435	100.9	'PIONEER TAP - PLYMELL 115KV CKT 1'
G08_079	3	101	83.5	11WP	'TO->FROM'	CIMARRON RIVER TAP - KISMET 3 115KV CKT 1'	120.7	129.5	0.2435	103.1	'HOLCOMB - PLYMELL 115KV CKT 1'
G08_079	3	101	69	11WP	'TO->FROM'	CIMARRON RIVER TAP - KISMET 3 115KV CKT 1'	120.7	129.5	0.5809	113.9584	'NORTH JUDSON LARGE SUB - SPEARVILLE 115KV CKT 1'
G08_079	3	101	72.6	11WP	'TO->FROM'	CIMARRON RIVER TAP - KISMET 3 115KV CKT 1'	120.7	129.5	0.5809	112.3159	'SPEARVILLE (SPEARVL6) 230/115/13.8KV TRANSFORMER CKT 1'
G08_079	3	101	95.7	11WP	'TO->FROM'	CIMARRON RIVER TAP - KISMET 3 115KV CKT 1'	120.7	129.5	0.2435	100.8655	'SPP-SUNC-14'
G08_079	3	101	85.5	11SP	'TO->FROM'	'CUDAHY - G08-79T 115.00 115KV CKT 1'	120.7	129.5	0.5817	106.4887	'NORTH JUDSON LARGE SUB - SPEARVILLE 115KV CKT 1'
G08_079	3	101	90.4	11SP	'TO->FROM'	CUDAHY - G08-79T 115KV CKT 1'	120.7	129.5	0.5817	104.2768	'SPEARVILLE (SPEARVL6) 230/115/13.8KV TRANSFORMER CKT 1'
G08_079	3	101	96.7	11WP	'FROM->TO'	CUDAHY - KISMET 3 115KV CKT 1'	120.7	129.5	0.3508	100.8611	'HOLCOMB - SPEARVILLE 345KV CKT 1'
G08_079	3	101	65.5	11WP	'FROM->TO'	CUDAHY - KISMET 3 115KV CKT 1'	120.7	129.5	0.5809	115.6107	'NORTH JUDSON LARGE SUB - SPEARVILLE 115KV CKT 1'
G08_079	3	101	96.3	11WP	'FROM->TO'	CUDAHY - KISMET 3 115KV CKT 1'	120.7	129.5	0.3508	100.9847	'SPEARVILLE (SPEARVL) 345/230/13.8KV TRANSFORMER CKT 1'
G08_079	3	101	69	11WP	'FROM->TO'	CUDAHY - KISMET 3 115KV CKT 1'	120.7	129.5	0.5809	113.9677	'SPEARVILLE (SPEARVL6) 230/115/13.8KV TRANSFORMER CKT 1'
G08_079	3	101	86.7	11WP	'FROM->TO'	CUDAHY - KISMET 3 115KV CKT 1'	120.7	129.5	0.2435	102.5051	'SPP-SUNC-14'
G08_079	3	101	74.6	11WP	'FROM->TO'	'FLATRDG3 138.00 - HARPER 138KV CKT 1'	105.2	105.2	0.2199	105.2853	'NORTH JUDSON LARGE SUB - SPEARVILLE 115KV CKT 1'
G08_079	3	101	78.4	11WP	'FROM->TO'	'FLATRDG3 138.00 - HARPER 138KV CKT 1'	105.2	105.2	0.2199	104.5454	'SPEARVILLE (SPEARVL6) 230/115/13.8KV TRANSFORMER CKT 1'

5.0 Power Factor Analysis

All contingencies were tested in power flow to determine the power factor requirements for the wind farm study project to maintain scheduled voltage at the point of interconnection (POI). The voltage schedule was set equal to the voltage at the POI under no fault conditions, with a minimum of 1.0 per unit. A fictitious reactive power source was added to the study project to maintain scheduled voltage during all studied contingencies. The MW and Mvar injections from the study project at the POI were recorded and the resulting power factors were calculated for all contingencies for both summer peak and winter peak cases (see Appendix A for the data). The most leading and most lagging power factors determine the minimum power factor range capability that the study project must install before commercial operation.

Per FERC and SPP Tariff requirements, if the power factor needed to maintain scheduled voltage were less than 0.95 lagging, then the requirement would be set to 0.95 lagging. This limit was not reached for the study project. The limit for leading power factor requirement is also 0.95, and this limit was not reached for the study project.

6.0 Stability Analysis

6.1 Contingencies Simulated

Thirty-six (36) contingencies were considered for the transient stability simulations. These contingencies included three phase faults and single phase line faults at 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 faults that were defined and simulated are listed in Table 2 below.

Table 2: Contingencies Evaluated

Cont. No.	Cont. Name	Description
1	FLT03-3PH	3 phase fault on the Spearville (531469) to Holcomb (531449) 345kV lines, near Spearville. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
2	FLT4-1PH	*Single phase fault and sequence like previous*
3	FLT5-3PH	3 phase fault on the Judson Large (539671) to Dodge City Beef (539645) 115kV line, near Judson Large. a. Apply fault at the Judson Large 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
4	FLT6-1PH	*Single phase fault and sequence like previous*
5	FLT9-3PH	3 phase fault on the Holcomb 345kV / 115kV autotransformer near the 345 kV bus (531449). a. Apply fault at the Holcomb 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
6	FLT10-1PH	*Single phase fault and sequence like previous*
7	FLT15-3PH	3 phase fault on the Spearville 345kV / 230kV autotransformer near the 345 kV bus (531469). a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
8	FLT16-1PH	*Single phase fault and sequence like previous*
9	FLT17-3PH	3 phase fault on the Judson Large (539671) to Greenburg (539664) 115kV line, near Judson Large. a. Apply fault at the Judson Large 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
10	FLT18-1PH	*Single phase fault and sequence like previous*
11	FLT19-3PH	3 phase fault on the Spearville 230kV / 115kV autotransformer near the 230 kV bus (539695). a. Apply fault at the Spearville 230kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
12	FLT20-1PH	*Single phase fault and sequence like previous*
13	FLT21-3PH	3 phase fault on the Spearville (539695) to Mullergren (539679) 230kV line, near Spearville. a. Apply fault at the Spearville 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
14	FLT22-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
15	FLT23-3PH	3 phase fault on the Mullergren (539679) to South Hays (530582) 230kV line, near Mullergren. a. Apply fault at the Mullergren 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
16	FLT24-1PH	*Single phase fault and sequence like previous*
17	FLT25-3PH	3 phase fault on the Mullergren (539679) to Circle (532871) 230kV line, near Mullergren. a. Apply fault at the Mullergren 230kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
18	FLT26-1PH	*Single phase fault and sequence like previous*
19	FLT35-3PH	3 phase fault on the Judson Large (539671) to North Jusdson Large (539771) 115kV line, near Judson Large. a. Apply fault at the Judson Large 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
20	FLT36-1PH	*Single phase fault and sequence like previous*
21	FLT37-3PH	3 phase fault on the Spearville (531469) to Knoll (560004) 345kV line, near Spearville. a. Apply fault at the Spearville 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
22	FLT38-1PH	*Single phase fault and sequence like previous*
23	FLT39-3PH	3 phase fault on the Knoll (560004) to Axtell (640065) 345kV line, near Knoll. a. Apply fault at the Knoll 345kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
24	FLT40-1PH	*Single phase fault and sequence like previous*
25	FLT41-3PH	3 phase fault on the Knoll 345kV (560004) to 230kV (530558) transformer, near the 345 kV bus. a. Apply fault at the Knoll 345kV bus. b. Clear fault after 5 cycles by tripping the faulted transformer.
26	FLT42-1PH	*Single phase fault and sequence like previous*
27	FLT49-3PH	3 phase fault on the Cimarron River Tap (539652) to Cimarron Plant (539654) 115kV line, near Cimarron River Tap. a. Apply fault at the Cimarron River Tap 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
28	FLT50-1PH	*Single phase fault and sequence like previous*

Cont. No.	Cont. Name	Description
29	FLT51-3PH	3 phase fault on the Cimarron River Tap (539652) to East Liberal (539672) 115kV line, near Cimarron River Tap. a. Apply fault at the Cimarron River Tap 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
30	FLT52-1PH	*Single phase fault and sequence like previous*
31	FLT55-3PH	3 phase fault on the Spearville (539694) to North Judson Large (539771) 115kV line, near Spearville. a. Apply fault at the Spearville 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
32	FLT56-1PH	*Single phase fault and sequence like previous*
33	FLT57-3PH	3 phase fault on the GEN-2008-079T (573029) to Judson Large (539671) 115kV line, near GEN-2008-079T. a. Apply fault at the GEN-2008-079T 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
34	FLT58-1PH	*Single phase fault and sequence like previous*
35	FLT55-3PH	3 phase fault on the GEN-2008-079T (573029) to Cudahy (539659) 115kV line, near GEN-2008-079T. a. Apply fault at the GEN-2008-079T 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
36	FLT56-1PH	*Single phase fault and sequence like previous*

6.2 Further Model Preparation

The base cases contain prior queued projects as shown in Table 3.

The wind generation from the study customer and the previously queued customers were dispatched into the SPP footprint.

Initial simulations were carried out on both base cases and cases with the added generation for a no-disturbance run of 20 seconds to verify the numerical stability of the model. All cases were confirmed to be stable.

Table 3: Prior Queued Projects Included

Project	MW
Montezuma	110
GEN-2002-025A	150
GEN-2004-014	50
GEN-2001-039M	99
GEN-2006-021	100
GEN-2003-019	250

The projects in Table 4. are higher or equally queued projects that are not included in this analysis. If any of these projects come into service, this study will need to be re-performed to determine if any interim capacity is available.

Table 4: Prior Queued Projects Not Included

Project	MW
GEN-2001-039A	105
GEN-2004-014	100
GEN-2005-012	250
GEN-2006-006	205
GEN-2007-038	200
GEN-2007-040	200
GEN-2008-018	405
GEN-2008-124	200

6.3 Results

Results of the stability analysis are summarized in Table 4. The results indicate that for all contingencies studied the transmission system remains stable.

Stability plots for the simulations are in Appendix B.

Table 4: Results of Simulated Contingencies

Cont. No.	Cont. Name	Description	2010 Summer	2010 Winter
1	FLT03-3PH	3 phase fault on the Spearville (531469) to Holcomb (531449) 345kV lines, near Spearville.	Stable	Stable
2	FLT4-1PH	*Single phase fault and sequence like previous*	Stable	Stable
3	FLT5-3PH	3 phase fault on the Judson Large (539671) to Dodge City Beef (539645) 115kV line, near Judson Large.	Stable	Stable
4	FLT6-1PH	*Single phase fault and sequence like previous*	Stable	Stable
5	FLT9-3PH	3 phase fault on the Holcomb 345kV / 115kV autotransformer near the 345 kV bus (531449).	Stable	Stable
6	FLT10-1PH	*Single phase fault and sequence like previous*	Stable	Stable
7	FLT15-3PH	3 phase fault on the Spearville 345kV / 230kV autotransformer near the 345 kV bus (531469).	Stable	Stable
8	FLT16-1PH	*Single phase fault and sequence like previous*	Stable	Stable
9	FLT17-3PH	3 phase fault on the Judson Large (539671) to Greenburg (539664) 115kV line, near Judson Large.	Stable	Stable
10	FLT18-1PH	*Single phase fault and sequence like previous*	Stable	Stable
11	FLT19-3PH	3 phase fault on the Spearville 230kV / 115kV autotransformer near the 230 kV bus (539695).	Stable	Stable
12	FLT20-1PH	*Single phase fault and sequence like previous*	Stable	Stable
13	FLT21-3PH	3 phase fault on the Spearville (539695) to Mullergren (539679) 230kV line, near Spearville.	Stable	Stable
14	FLT22-1PH	*Single phase fault and sequence like previous*	Stable	Stable
15	FLT23-3PH	3 phase fault on the Mullergren (539679) to South Hays (530582) 230kV line, near Mullergren.	Stable	Stable
16	FLT24-1PH	*Single phase fault and sequence like previous*	Stable	Stable
17	FLT25-3PH	3 phase fault on the Mullergren (539679) to Circle (532871) 230kV line, near Mullergren.	Stable	Stable
18	FLT26-1PH	*Single phase fault and sequence like previous*	Stable	Stable
19	FLT35-3PH	3 phase fault on the Judson Large (539671) to North Jusdson Large (539771) 115kV line, near Judson Large.	Stable	Stable
20	FLT36-1PH	*Single phase fault and sequence like previous*	Stable	Stable
21	FLT37-3PH	3 phase fault on the Spearville (531469) to Knoll (560004) 345kV line, near Spearville.	Stable	Stable
22	FLT38-1PH	*Single phase fault and sequence like previous*	Stable	Stable
23	FLT39-3PH	3 phase fault on the Knoll (560004) to Axtell (640065) 345kV line, near Knoll.	Stable	Stable
24	FLT40-1PH	*Single phase fault and sequence like previous*	Stable	Stable
25	FLT41-3PH	3 phase fault on the Knoll 345kV (560004) to 230kV (530558) transformer, near the 345 kV bus.	Stable	Stable
26	FLT42-1PH	*Single phase fault and sequence like previous*	Stable	Stable

Cont. No.	Cont. Name	Description	2010 Summer	2010 Winter
27	FLT49-3PH	3 phase fault on the Cimarron River Tap (539652) to Cimarron Plant (539654) 115kV line, near Cimarron River Tap.	Stable	Stable
28	FLT50-1PH	*Single phase fault and sequence like previous*	Stable	Stable
29	FLT51-3PH	3 phase fault on the Cimarron River Tap (539652) to East Liberal (539672) 115kV line, near Cimarron River Tap.	Stable	Stable
30	FLT52-1PH	*Single phase fault and sequence like previous*	Stable	Stable
31	FLT55-3PH	3 phase fault on the Spearville (539694) to North Judson Large (539771) 115kV line, near Spearville.	Stable	Stable
32	FLT56-1PH	*Single phase fault and sequence like previous*	Stable	Stable
33	FLT57-3PH	3 phase fault on the GEN-2008-079T (573029) to Judson Large (539671) 115kV line, near GEN-2008-079T.	Stable	Stable
34	FLT58-1PH	*Single phase fault and sequence like previous*	Stable	Stable
35	FLT55-3PH	3 phase fault on the GEN-2008-079T (573029) to Cudahy (539659) 115kV line, near GEN-2008-079T.	Stable	Stable
36	FLT56-1PH	*Single phase fault and sequence like previous*	Stable	Stable

6.4 FERC LVRT Compliance

FERC Order #661A places specific requirements on wind farms through its Low Voltage Ride Through (LVRT) provisions. For Interconnection Agreements signed after December 31, 2006, wind farms shall stay on line for faults at the POI that draw the voltage down at the POI to 0.0 pu.

Two fault contingencies were developed to verify that the wind farm will remain on line when the POI voltage is drawn down to 0.0 pu. These contingencies are shown in Table 5.

Table 5: LVRT Fault Contingencies

Cont. Name	Description
FLT57-3PH	3 phase fault on the GEN-2008-079T (573029) to Judson Large (539671) 115kV line, near GEN-2008-079T. a. Apply fault at the GEN-2008-079T 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.
FLT55-3PH	3 phase fault on the GEN-2008-079T (573029) to Cudahy (539659) 115kV line, near GEN-2008-079T. a. Apply fault at the GEN-2008-079T 115kV bus. b. Clear fault after 5 cycles by tripping the faulted line. c. Wait 20 cycles, and then re-close the line in (b) back into the fault. d. Leave fault on for 5 cycles, then trip the line in (b) and remove fault.

The project wind farm remained online for the fault contingencies described in this section and for all the fault contingencies described in section 6.2. GEN-2008-079 is found to be in compliance with FERC Order #661A.

7.0 Conclusion

<OMITTED TEXT> (Customer) has requested an Interim Operation Impact Study for interim interconnection service of 99.5 MW of wind generation within the balancing authority of Sunflower Electric Power Corporation in Gray County, Kansas, in accordance with the OASIS posting made by SPP on March 6, 2009.

The results of this study show that the wind generation facility and the transmission system remain stable for all contingencies studied. Also, GEN-2008-079 is found to be in compliance with FERC Order #661A.

Due to the existing transmission system line capacity near GEN-2008-079, the Customer's wind facility is limited to a maximum of 65.5MW during the interim operation.

The Customer's wind facility must be capable of meeting a 0.99 lagging to 0.96 leading power factor at the POI.

The Customer will also be required to provide security in the amount of $12,000,000 per the Facility Study for GEN-2008-079 in addition to the $3,267,000 in interconnection substation costs in order to move forward into an Interim Interconnection Agreement. Failure by the Customer to provide the security in this amount in accordance with the Interim Interconnection will cause this Interim Operation Impact Study and the Interim Interconnection Agreement to become invalid. The amount of security will be adjusted as the GEN-2008-079 interconnection request advances through the Cluster interconnection process as stated in SPP's OASIS posting.

The projects in Table 4. are higher or equally queued projects that are not included in this analysis. If any of these projects come into service, this study will need to be re-performed to determine if any interim capacity is available.

The estimates do not include any costs associated with the deliverability of the energy to final customers. These costs are determined by separate studies if the Customer requests transmission service through Southwest Power Pool's OASIS. It should be noted that the models used for simulation do not contain all SPP transmission service.

APPENDIX A.

POWER FACTOR DATA

Contingency. No.	Contingency. Name	2010 Summer				2009 Winter			
		Power @ POI	**VARS @ POI**	**Power Factor**		**Power @ POI**	**VARS @ POI**	**Power Factor**	
0	No Fault	-96.3	12.1	0.9922	Leading	-96.3	18.2	0.9826	Leading
1	FLT03-3PH	-96.3	13.3	0.9906	Leading	-96.3	17.9	0.9832	Leading
3	FLT5-3PH	-96.3	11.5	0.9929	Leading	-96.3	19.4	0.9803	Leading
***5**	**FLT9-3PH**	-96.3	16	0.9865	Leading	**-96.3**	**26**	**0.9654**	**Leading**
7	FLT15-3PH	-96.3	2.1	0.9998	Leading	-96.3	8.4	0.9962	Leading
9	FLT17-3PH	-96.2	5.5	0.9984	Leading	-96.3	13.6	0.9902	Leading
11	FLT19-3PH	-96.3	-3.1	0.9995	Lagging	-96.3	2.9	0.9995	Leading
13	FLT21-3PH	-96.3	9.8	0.9949	Leading	-96.3	17.5	0.9839	Leading
15	FLT23-3PH	-96.4	12	0.9923	Leading	-96.3	18.1	0.9828	Leading
17	FLT25-3PH	-96.3	11.9	0.9925	Leading	-96.3	18.2	0.9826	Leading
19	FLT35-3PH	-96.3	14.9	0.9882	Leading	-96.3	18.1	0.9828	Leading
21	FLT37-3PH	-96.3	7.3	0.9971	Leading	-96.3	14.8	0.9884	Leading
23	FLT39-3PH	-96.3	10.6	0.9940	Leading	-96.3	16.6	0.9855	Leading
25	FLT41-3PH	-96.3	12.7	0.9914	Leading	-96.3	18.4	0.9822	Leading
27	FLT49-3PH	-96.3	9.8	0.9949	Leading	-96.3	17.2	0.9844	Leading
29	FLT51-3PH	-96.3	11.7	0.9927	Leading	-96.3	16.6	0.9855	Leading
***31**	**FLT55-3PH**	**-96.3**	**-3.6**	**0.9993**	**Lagging**	-96.3	3.6	0.9993	Leading
33	FLT57-3PH	-96.3	7.6	0.9969	Leading	-96.3	11.3	0.9932	Leading
35	FLT55-3PH	-96.3	16.4	0.9858	Leading	-96.3	24.9	0.9682	Leading

* Indicates the least leading and lagging power factors.

APPENDIX B.

STABILITY PLOTS

All plots available on request.