SPP Southwest Power Pool

Interim Operational Impact Study For Generation Interconnection Request GEN-2006-044N

SPP Tariff Studies

(#GEN-2006-044N)

August 2010

Executive Summary

<OMITTED TEXT> (Customer) has requested an Impact Study under the Southwest Power Pool Open Access Transmission Tariff (OATT) for interconnection of 40.5 MW of wind generation within the balancing authority of Nebraska Public Power District (NPPD) in Boone County, Nebraska. SPP expects to complete the Impact Study as part of the cluster study DISIS-2009-001-1. 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 31, 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-2009-001-1 posted on March 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 4 of this study might go into service before the completion of all Network Upgrades identified in DISIS-2009-001-1. If any additional generation projects not identified in Table 4 but with queue priority over GEN-2006-044N request to go into commercial operation before all Network Upgrades identified through the DISIS-2009-001-1 study process as required, then this study must be conducted again to determine whether sufficient interim interconnection capacity exists to interconnect the GEN-2006-044N interconnection request in addition to all higher priority requests in operation or pending operation.

A power flow analysis showed that the maximum power that the Customer's wind facility can inject into the NPPD transmission system is 34.5 MW due to line capacity of the Albion-Petersburg-Neligh 115kV transmission line. Powerflow analysis was based on both summer and winter peak conditions and light loading cases.

An analysis of prior outage conditions shows that for a prior outage of the Neligh-County Line 115kV transmission line, the generation facility will be curtailed to at least 26MW.

A power factor analysis at the point of interconnection (POI) determined that the Customer's wind facility must be capable of meeting 0.997 lagging and 0.950 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 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 twenty-seven (27) General Electric 1.5 MW wind turbine generators. This Impact study addresses the dynamic stability effects of interconnecting the plant to the rest of the NPPD transmission system for the system condition as it will be on December 31, 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. Forty (40) contingencies were identified for use in this study. The GE 1.5MW 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 $1,300,000. The Customer will also be required to provide security in the amount of $10,000,000 per DISIS-2009-001 Facility Study. This amount of security will be adjusted as the GEN-2006-044N 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 40.5 MW of wind generation within the balancing authority of Nebraska Public Power District (NPPD) in Boone County, Nebraska. SPP expects to complete the Impact Study as part of the cluster study DISIS-2009-001-1. 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 31, 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-2009-001-1 posted on March 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 NPPD transmission system for the system condition as it will be on December 31, 2010. The wind generation facility was studied with twenty-seven (27) General Electric 1.5 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. Forty (40) 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 4; 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 a single wind turbine generator of 40.5MW output. The wind turbine is connected to a 0.69/34.5KV generator step unit (GSU) with rating of 47.25MVA and an impedance of 5.75%. The high side of the GSU is connected to the 34.5/115kV substation transformer. The substation transformer is rated 27/45 MVA with 10% impedance on the 27MVA base. A 115kV transmission line connects the Customer's substation transformer to the POI.

3.2 <u>Interconnection Facility</u>

The Point of Interconnection will be at the Transmission Owner's Petersburg North Substation. Figure 1 shows the proposed POI.

Cost to interconnect on an Interim basis is estimated at **$1,300,000**.

Customer's latest estimate for cost responsibility for Interconnection Service is given in DISIS-2009-001-1 at **$10,000,000**. The Customer will be required to provide security in this amount to move forward into an Interim Interconnection Agreement.

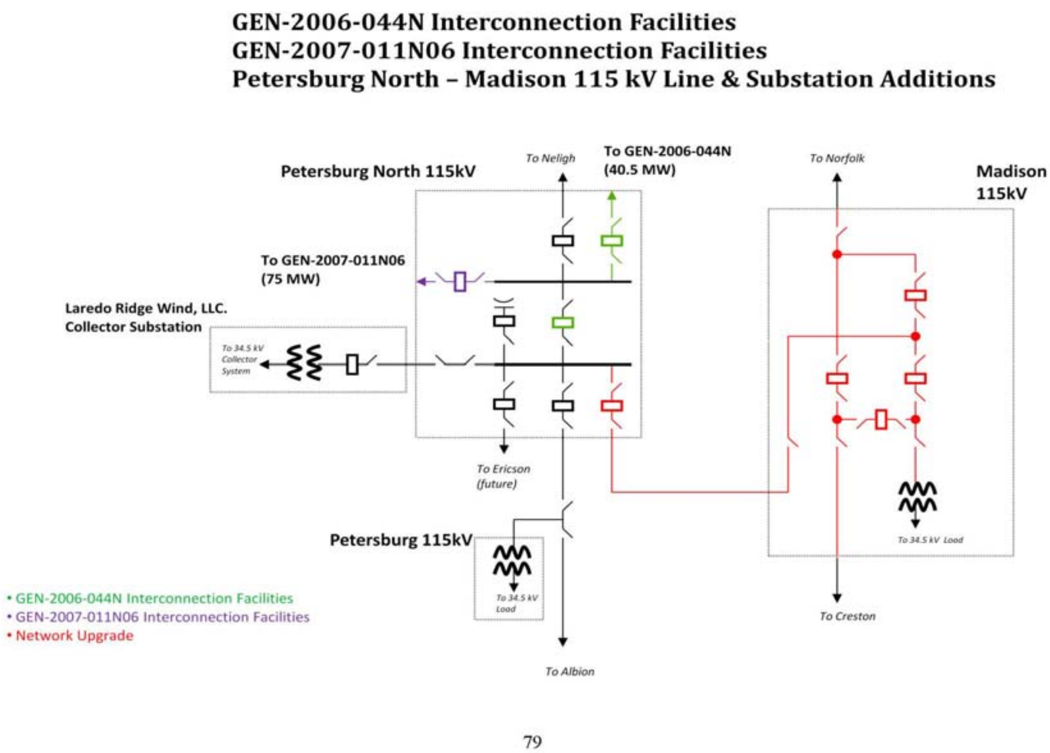

Figure 1: GEN-2006-044N Facility and Proposed Interconnection Configuration

4.0 Power Flow Analysis

A powerflow analysis was conducted for the Interconnection Customer's facility using a modified version of the 2010 spring, 2014 summer, and 2014 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 in the immediate area of this interconnect request 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 areas of NPPD, WAPA, 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.

The ACCC analysis indicates that as a result of the Customer's project at full nameplate power the NPPD 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 34.5 MW for the interim operational interconnection.

Prior Outage Conditions Analysis

At the request of the Transmission Owner, SPP conducted a prior outage analysis to determine the operational limits for certain operating conditions. A full n-1 analysis was conducted on the 10G and 14SP cases for the following scenarios

1. Prior outage of the Neligh – County Line 115kV line
2. Prior outage of the Petersburg North – Neligh 115kV line
3. Prior outage of the Petersburg – Albion 115kV line

The prior outage conditions analysis shows that the wind farm will be curtailed to at least 26MW for the prior outage of the Neligh – County Line 115kV line.

Table 1: ACCC Analysis

SEASON	SC	DIRECTION	MONTCOMMONNAME	RATE A	RATEB	TDF	TC%LOADING	MW	CONTNAME
10G	0	'TO->FROM'	'ALBION - PETERSBURG 115KV CKT 1'	113	113	0.99718	104.16	35.8	'NELIGH - PETERSB_N 115.00 115KV CKT 1'
10G	0	'TO->FROM'	'NELIGH - PETERSB_N 115.00 115KV CKT 1'	113	113	0.99718	105.33	34.5	'ALBION - PETERSBURG 115KV CKT 1'
10G	1	'TO->FROM'	'ALBION - PETERSBURG 115KV CKT 1'	113	113	0.99718	104.17	35.8	'NELIGH - PETERSB_N 115.00 115KV CKT 1'
10G	1	'TO->FROM'	'NELIGH - PETERSB_N 115.00 115KV CKT 1'	113	113	0.99718	104.25	35.7	'ALBION - PETERSBURG 115KV CKT 1'
10G	1	'FROM->TO'	'BLOOMFIELD - GAVINS POINT 115KV CKT 1'	120	120	0.48978	109.68	34.8	'ALBION - PETERSBURG 115KV CKT 1'
10G	1	'TO->FROM'	'ALBION - PETERSBURG 115KV CKT 1'	113	113	0.69394	117.7	26.6	'BLOOMFIELD - GAVINS POINT 115KV CKT 1'
10G	2	'TO->FROM'	'ALBION - PETERSBURG 115KV CKT 1'	113	113	0.99718	104.16	35.8	'BASE CASE'
10G	2	'FROM->TO'	'ALBION - SPALDING 115KV CKT 1'	80	80	0.99704	113.11	30.0	'COLUMBUS - GENOA 115KV CKT 1'
10G	2	'FROM->TO'	'ALBION - SPALDING 115KV CKT 1'	80	80	0.99718	114.9	28.6	'ALBION - GENOA 115KV CKT 1'
10G	3	'TO->FROM'	'NELIGH - PETERSB_N 115.00 115KV CKT 1'	113	113	0.99718	105.33	34.5	'BASE CASE'
10G	3	'FROM->TO'	'BLOOMFIELD - GAVINS POINT 115KV CKT 1'	120	120	0.48978	107.07	36.3	'BATTLE CREEK - NORTH NORFOLK 115KV CKT 1'
10G	3	'FROM->TO'	'BLOOMFIELD - GAVINS POINT 115KV CKT 1'	120	120	0.48978	109.46	34.9	'BATTLE CREEK - COUNTY LINE 115KV CKT 1'
10G	3	'FROM->TO'	'BLOOMFIELD - GAVINS POINT 115KV CKT 1'	120	120	0.48978	109.6	34.9	'LN-1163'
10G	3	'FROM->TO'	'BLOOMFIELD - GAVINS POINT 115KV CKT 1'	120	120	0.48978	109.67	34.8	'COUNTY LINE - NELIGH 115KV CKT 1'
10G	3	'FROM->TO'	'BATTLE CREEK - NORTH NORFOLK 115KV CKT 1'	120	120	0.65675	111.7	31.3	'BLOOMFIELD - GAVINS POINT 115KV CKT 1'
10G	3	'TO->FROM'	'BATTLE CREEK - COUNTY LINE 115KV CKT 1'	120	120	0.65675	116.23	27.7	'BLOOMFIELD - GAVINS POINT 115KV CKT 1'

10G	3	'TO->FROM'	'COUNTY LINE - NELIGH 115KV CKT 1'	120	120	0.65675	116.77	27.3	'BLOOMFIELD - GAVINS POINT 115KV CKT 1'
14SP	0	'TO->FROM'	'ALBION - PETERSBURG 115KV CKT 1'	113	113	0.99718	103.5	36.6	'NELIGH - PETERSB_N 115.00 115KV CKT 1'
14SP	0	'TO->FROM'	'NELIGH - PETERSB_N 115.00 115KV CKT 1'	113	113	0.99718	103.5	36.6	'ALBION - PETERSBURG 115KV CKT 1'
14SP	0	'TO->FROM'	'NELIGH - PETERSB_N 115.00 115KV CKT 1'	113	113	0.99718	103.5	36.6	'ALBION - PETERSBURG 115KV CKT 1'
14SP	3	'TO->FROM'	'NELIGH - PETERSB_N 115.00 115KV CKT 1'	113	113	0.99811	102.77	37.4	'PETERSBURG 115KV SWITCHED SHUNT'
14WP	0	'TO->FROM'	'ALBION - PETERSBURG 115KV CKT 1'	113	113	0.99718	104.4	35.5	'NELIGH - PETERSB_N 115.00 115KV 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 reached for the study project.

The final power factor requirements are shown in Table 2 below. These are only the minimum power factor ranges based on steady-state analysis. A project developer may install more capability than this if desired.

Table 2: Power Factor Requirements [1]

Project	MW	Turbine	POI	Final PF Requirement	
				Lagging [2]	Leading [3]
GEN-2006-044N	40.5	GE 1.5MW	Tap Neligh – Petersburg 115kV line	0.997	0.950

Notes:
1. For each plant, the table shows the minimum required power factor capability at the point of interconnection that must be designed and installed with the plant. The power factor capability at the POI includes the net effect of the generators, transformers, line impedances, and any reactive compensation devices installed on the plant side of the meter. Installing more capability than the minimum requirement is acceptable.
2. Lagging is when the generating plant is supplying reactive power to the transmission grid. In this situation, the alternating current sinusoid “lags” behind the alternating voltage sinusoid, meaning that the current peaks shortly after the voltage.
3. Leading is when the generating plant is taking reactive power from the transmission grid. In this situation, the alternating current sinusoid “leads” the alternating voltage sinusoid, meaning that the current peaks shortly before the voltage.

6.0 Stability Analysis

6.1 Modeling of the Generators for the Stability Simulation

The modeling of the Customer’s wind facility is the same as the power flow except that an equivalent collector system impedance branch was inserted between the GSU and the substation step up transformer. The impedance of this branch is Z=0.003+j0.0073, B=0.04.

The Customer provided the PSSE Version 30.3.3 model for the GE 1.5MW wind turbines.

6.2 Contingencies Simulated

Forty (40) 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 3 below.

Table 3: Contingencies Evaluated

Cont. No.	Cont. Name	Description
1	FLT01-3PH	3 phase fault on the GEN-2006-044N (570644) to Neligh (640293) 115kV line, near GEN-2006-044N. a. Apply fault at the GEN-2006-044N 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted line.
2	FLT02-3PH	3 phase fault on the GEN-2006-044N (570644) to Petersburg (640318) 115kV line, near GEN-2006-044N. a. Apply fault at the GEN-2006-044N 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted line.
3	FLT03-3PH	3 phase fault on the Albion (640054) to Petersburg (640318) 115kV line, near Petersburg. a. Apply fault at the Petersburg 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
4	FLT04-3PH	3 phase fault on the Albion (640054) to Fullerton (640176) 115kV line, near Albion. a. Apply fault at the Albion 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
5	FLT05-3PH	3 phase fault on the Albion (640054) to Genoa (640181) 115kV line, near Albion. a. Apply fault at the Albion 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
6	FLT6-3PH	3 phase fault on the Albion (640054) to Spalding (640347) 115kV line, near Albion. a. Apply fault at the Albion 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
7	FLT7-3PH	3 phase fault on the Clearwater (640113) to Neligh (640293) 115kV line, near Neligh. a. Apply fault at the Neligh 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted lines (Neligh-Clearwater-O'Neill 115 kV).
8	FLT8-3PH	3 phase fault on the County Line (640115) to Neligh (640293) 115kV line, near Neligh. a. Apply fault at the Neligh 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted lines (Neligh-CountyLine-BattleCreek-NorthNorfolk 115 kV).
9	FLT9-3PH	3 phase fault on the Creighton (640149) to Neligh (640293) 115kV line, near Neligh. a. Apply fault at the Neligh 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted line.
10	FLT10-3PH	3 phase fault on the O'Neill (640305) to Spencer (640349) 115kV line, near O'Neill. a. Apply fault at the O'Neill 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted lines (O'Neill-Spencer-Ft.Randall 115 kV).

Cont. No.	Cont. Name	Description
11	FLT11-3PH	3 phase fault on the O’Neill (640305) to Emmett (640165) 115kV line, near O’Neill. a. Apply fault at the O’Neill 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted lines (O’Neill-Emmet-Atkinson-Stuart-Ainsworth 115 kV).
12	FLT12-3PH	3 phase fault on the Ainsworth (640051) to Valentine (640392) 115kV line, near Ainsworth. a. Apply fault at the Ainsworth 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
13	FLT13-3PH	3 phase fault on the Ainsworth Wind (640050) to Ainsworth (640051) 115kV line, near Ainsworth. a. Apply fault at the Ainsworth 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
14	FLT14-3PH	3 phase fault on the Ainsworth Wind (640050) to Calamus (640096) 115kV line, near Ainsworth Wind. a. Apply fault at the Ainsworth Wind 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted lines (AinsworthWind-Calamus-Thedford 115 kV).
15	FLT15-3PH	3 phase fault on the Bloomfield (640084) to Creighton (640149) 115kV line, near Bloomfield. a. Apply fault at the Bloomfield 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
16	FLT15-3PH1	3 phase fault on the Bloomfield (640084) to Gavins (652511) 115kV line, near Bloomfield. a. Apply fault at the Bloomfield 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
17	FLT16-3PH	3 phase fault on the Hartington (640212) to Gavins (652511) 115kV line, near Hartington. a. Apply fault at the Gavins Point 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
18	FLT17-3PH	3 phase fault on the Yankton (652532) to Gavins (652511) 115kV line, near Yankton. a. Apply fault at the Gavins Point 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
19	FLT18-3PH	3 phase fault on the Yankton Jct (660006) to Gavins (652511) 115kV line, near Yankton Jct a. Apply fault at the Yankton Jct 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.
20	FLT19-3PH	3 phase fault on the Shell Creek (640343) to Kelly (640133) 230kV line, near Columbus a. Apply fault at the Kelly 230kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
21	FLT20-3PH	3 phase fault on the Columbus West (640131) to Kelly (640133) 230kV line, near Columbus a. Apply fault at the Kelly 230kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
22	FLT21-3PH	3 phase fault on the East Columbus (640126) to Kelly (640133) 230kV line, near Columbus a. Apply fault at the Kelly 230kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
23	FLT22-3PH	3 phase fault on the GEN-2008-086N02 (570886) to Kelly (640133) 230kV line, near GEN-2008-086N02 a. Apply fault at the GEN-2008086N02 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.

Cont. No.	Cont. Name	Description
24	FLT23-3PH	3 phase fault on the GEN-2008-086N02 (570886) to Fort Randall (652509) 230kV line, near GEN-2008-086N02 a. Apply fault at the GEN-2008086N02 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
25	FLT24-3PH	3 phase fault on the Fort Randall (652509) to Fort Thompson (652507) 230kV line, near GEN-Fort Randall a. Apply fault at the Ft. Randall 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
26	FLT25-3PH	3 phase fault on the Fort Randall (652509) to Utica Jct (652526) 230kV line, near Fort Randall a. Apply fault at the Fort Randall 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
27	FLT26-3PH	3 phase fault on the Fort Randall (652509) to Lake Platt (652516) 230kV line, near Fort Randall a. Apply fault at the Fort Randal 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
28	FLT27-3PH	3 phase fault on the Fort Randall (652509) to Sioux City (652565) 230kV line, near Fort Randall a. Apply fault at the Fort Randal 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.
29	FLT28-3PH	3 phase fault on the Kelly 230/115 kV auto at the 115kV (640134) a. Apply fault at the Columbus 115kV bus. b. Clear fault after 5.5 cycles by tripping autotransformer.
30	FLT29-3PH	3 phase fault on the Spirit Mound (659121) to Manning (652517) 115 kV line, near Spirit Mound. a. Apply fault at the Manning 115 kV bus (652517). b. Clear fault after 6.5 cycles by tripping the faulted line.
31	FLT30-1PH	SLG fault on Bloomfield – Gavins Point 115 kV line, near Bloomfield. Stuck breaker at Gavins. a. Apply fault at Bloomfield 115 kV bus. b. Clear Bloomfield end of line at 5.5 cycles. Leave fault on end of open-ended line from Gavins Point. c. Clear Gavins Point 115 kV bus and fault at 18.0 cycles.
32	FLT31-1PH	SLG fault on Creighton – Neligh 115 kV line, near Creighton. Stuck breaker at Creighton. a. Apply fault at Creighton 115 kV bus. b. Clear Neligh end of line at 6.5 cycles. Leave fault on open-ended line from Creighton. c. Clear Creighton 115 kV bus and fault at 18.0 cycles.
33	FLT32-1PH	SLG fault on Gavins Point – Hartington 115 kV line, near Gavins Point. Stuck breaker at Gavins Point. a. Apply fault at Gavins Point 115 kV bus. b. Clear Hartington end of line at 6.5 cycles. Leave fault on open-ended line from Gavins Point. c. Clear Gavins Point 115 kV bus and fault at 18.0 cycles.
34	FLT33-1PH	SLG fault on Neligh-County Line, near Neligh. Stuck PCB at Neligh. a. Apply fault at Neligh 115 kV bus. b. Clear North Norfolk end of Neligh-CountyLine-BattleCreek-NorthNorfolk 115 kV line at 6.5 cycles. Leave fault on open-ended line. c. Clear Neligh 115 kV bus and fault at 18.0 cycles.
35	FLT34-1PH	SLG fault on Albion-Genoa 115 kV line near Albion. Stuck PCB at Albion. a. Apply fault on Albion 115 kV bus. b. Clear Genoa end of Albion-Genoa 115 kV line at 6.5 cycles. Leave fault on open-ended line. c. Clear Albion 115 kV bus and fault at 18.0 cycles.

Cont. No.	Cont. Name	Description
36	FLT35-1PH	SLG fault on Kelly – Columbus West 230 kV line. Stuck PCB at Kelly. a. Apply fault on Kelly 230 kV bus. b. Clear Columbus West end of line at 6.0 cycles. Leave fault on open-ended line. c. Clear Kelly 230 kV bus and fault at 14.5 cycles.
37	FLT36-3PH	3PH fault on Spirit Mound – Manning 115 kV line with prior outage of Gavins Point – Yankton Junction 115 kV. a. Prior Outage: Gavins Point – Yankton Junction 115 kV line b. Apply 3PH fault on Manning115 kV bus. c. Clear fault after 6.5 cycles and trip faulted Spirit Mound – Manning 115 kV line.
38	FLT37-3PH	3PH fault on Albion – Genoa 115 kV line with prior outage of Petersburg – Neligh 115 kV. a. Prior Outage: Petersburg – Neligh 115 kV line b. Apply 3PH fault on Albion 115 kV bus. c. Clear Albion end of Albion – Genoa 115 kV line in 5.5 cycles. Leave fault on end of line out of Genoa. d. Clear fault after 6.5 cycles and trip faulted Albion – Genoa 115 kV line.
39	FLT38-3PH	3PH fault on Gavins Point – Bloomfield 115 kV line with prior outage of Neligh – County Line 115 kV. a. Prior Outage: Neligh – County Line 115 kV b. Apply 3PH fault on Bloomfield 115 kV bus. c. Clear fault after 6.5 cycles and trip faulted Gavins Point – Bloomfield 115 kV line.
40	FLT39-3PH	3PH fault on Albion - Petersburg 115 kV line with prior outage of Neligh – County Line 115 kV. a. Prior Outage: Neligh – County Line 115 kV b. Apply 3PH fault on Petersburg 115 kV bus. c. Clear fault after 6.5 cycles and trip faulted Albion – Petersburg 115 kV line.

6.3 <u>Further Model Preparation</u>

The base cases contain prior queued projects as shown in Table 4.

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 4: Prior Queued Projects

Project	MW
GEN-2003-021N	75
GEN-2004-005N	30
GEN-2006-020N	42
GEN-2006-038N005	80
GEN-2006-038N019	79.5
GEN-2007-011N08	81

6.4 <u>Results</u>

Results of the stability analysis are summarized in Table 5. The results indicate that for all contingencies studied the transmission system remains stable.

Stability plots for the simulations are in Appendix B.

Table 5: Results of Simulated Contingencies

Cont. No.	Cont. Name	Description	2010 Summer	2010 Winter
1	FLT01-3PH	3 phase fault on the GEN-2006-044N (570644) to Neligh (640293) 115kV line, near GEN-2006-044N. a. Apply fault at the GEN-2006-044N 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted line.	STABLE	STABLE
2	FLT02-3PH	3 phase fault on the GEN-2006-044N (570644) to Petersburg (640318) 115kV line, near GEN-2006-044N. a. Apply fault at the GEN-2006-044N 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted line.	STABLE	STABLE
3	FLT03-3PH	3 phase fault on the Albion (640054) to Petersburg (640318) 115kV line, near Petersburg. a. Apply fault at the Petersburg 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	STABLE	STABLE
4	FLT04-3PH	3 phase fault on the Albion (640054) to Fullerton (640176) 115kV line, near Albion. a. Apply fault at the Albion 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	STABLE	STABLE
5	FLT05-3PH	3 phase fault on the Albion (640054) to Genoa (640181) 115kV line, near Albion. a. Apply fault at the Albion 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	S*TABLE*	STABLE
6	FLT6-3PH	3 phase fault on the Albion (640054) to Spalding (640347) 115kV line, near Albion. a. Apply fault at the Albion 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	STABLE	STABLE
7	FLT7-3PH	3 phase fault on the Clearwater (640113) to Neligh (640293) 115kV line, near Neligh. a. Apply fault at the Neligh 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted lines (Neligh-Clearwater-O'Neill 115 kV).	STABLE	STABLE
8	FLT8-3PH	3 phase fault on the County Line (640115) to Neligh (640293) 115kV line, near Neligh. a. Apply fault at the Neligh 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted lines (Neligh-CountyLine-BattleCreek-NorthNorfolk 115 kV).	STABLE	STABLE
9	FLT9-3PH	3 phase fault on the Creighton (640149) to Neligh (640293) 115kV line, near Neligh. a. Apply fault at the Neligh 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted line.	STABLE	STABLE

Cont. No.	Cont. Name	Description	2010 Summer	2010 Winter
10	FLT10-3PH	3 phase fault on the O'Neill (640305) to Spencer (640349) 115kV line, near O'Neill. a. Apply fault at the O'Neill 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted lines (O'Neill-Spencer-Ft.Randall 115 kV).	STABLE	STABLE
11	FLT11-3PH	3 phase fault on the O'Neill (640305) to Emmett (640165) 115kV line, near O'Neill. a. Apply fault at the O'Neill 115kVbus. b. Clear fault after 6.5 cycles by tripping the faulted lines (O'Neill-Emmet-Atkinson-Stuart-Ainsworth 115 kV).	STABLE	STABLE
12	FLT12-3PH	3 phase fault on the Ainsworth (640051) to Valentine (640392) 115kV line, near Ainsworth. a. Apply fault at the Ainsworth 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	STABLE	STABLE
13	FLT13-3PH	3 phase fault on the Ainsworth Wind (640050) to Ainsworth (640051) 115kV line, near Ainsworth. a. Apply fault at the Ainsworth 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	STABLE	STABLE
14	FLT14-3PH	3 phase fault on the Ainsworth Wind (640050) to Calamus (640096) 115kV line, near Ainsworth Wind. a. Apply fault at the Ainsworth Wind 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted lines (AinsworthWind-Calamus-Thedford 115 kV).	STABLE	STABLE
15	FLT15-3PH	3 phase fault on the Bloomfield (640084) to Creighton (640149) 115kV line, near Bloomfield. a. Apply fault at the Bloomfield 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	STABLE	STABLE
16	FLT15-3PH1	3 phase fault on the Bloomfield (640084) to Gavins (652511) 115kV line, near Bloomfield. a. Apply fault at the Bloomfield 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	STABLE	STABLE
17	FLT16-3PH	3 phase fault on the Hartington (640212) to Gavins (652511) 115kV line, near Hartington. a. Apply fault at the Gavins Point 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	STABLE	STABLE
18	FLT17-3PH	3 phase fault on the Yankton (652532) to Gavins (652511) 115kV line, near Yankton. a. Apply fault at the Gavins Point 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	STABLE	STABLE

Cont. No.	Cont. Name	Description	2010 Summer	2010 Winter
19	FLT18-3PH	3 phase fault on the Yankton Jct (660006) to Gavins (652511) 115kV line, near Yankton Jct a. Apply fault at the Yankton Jct 115kV bus. b. Clear fault after 6.5 cycles by tripping the faulted line.	STABLE	STABLE
20	FLT19-3PH	3 phase fault on the Shell Creek (640343) to Kelly (640133) 230kV line, near Columbus a. Apply fault at the Kelly 230kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	STABLE	STABLE
21	FLT20-3PH	3 phase fault on the Columbus West (640131) to Kelly (640133) 230kV line, near Columbus a. Apply fault at the Kelly 230kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	STABLE	STABLE
22	FLT21-3PH	3 phase fault on the East Columbus (640126) to Kelly (640133) 230kV line, near Columbus a. Apply fault at the Kelly 230kV bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	STABLE	STABLE
23	FLT22-3PH	3 phase fault on the GEN-2008-086N02 (570886) to Kelly (640133) 230kV line, near GEN-2008-086N02 a. Apply fault at the GEN-2008086N02 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	STABLE	STABLE
24	FLT23-3PH	3 phase fault on the GEN-2008-086N02 (570886) to Fort Randall (652509) 230kV line, near GEN-2008-086N02 a. Apply fault at the GEN-2008086N02 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	STABLE	STABLE
25	FLT24-3PH	3 phase fault on the Fort Randall (652509) to Fort Thompson (652507) 230kV line, near GEN-Fort Randall a. Apply fault at the Ft. Randall 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	STABLE	STABLE
26	FLT25-3PH	3 phase fault on the Fort Randall (652509) to Utica Jct (652526) 230kV line, near Fort Randall a. Apply fault at the Fort Randall 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	STABLE	STABLE
27	FLT26-3PH	3 phase fault on the Fort Randall (652509) to Lake Platt (652516) 230kV line, near Fort Randall a. Apply fault at the Fort Randal 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	STABLE	STABLE
28	FLT27-3PH	3 phase fault on the Fort Randall (652509) to Sioux City (652565) 230kV line, near Fort Randall a. Apply fault at the Fort Randal 230V bus. b. Clear fault after 6.0 cycles by tripping the faulted line.	STABLE	STABLE

Cont. No.	Cont. Name	Description	2010 Summer	2010 Winter
29	FLT28-3PH	3 phase fault on the Kelly 230/115 kV auto at the 115kV (640134) a. Apply fault at the Columbus 115kV bus. b. Clear fault after 5.5 cycles by tripping autotransformer.	STABLE	STABLE
30	FLT29-3PH	3 phase fault on the Spirit Mound (659121) to Manning (652517) 115 kV line, near Spirit Mound. c. Apply fault at the Manning 115 kV bus (652517). d. Clear fault after 6.5 cycles by tripping the faulted line.	STABLE	STABLE
31	FLT30-1PH	SLG fault on Bloomfield – Gavins Point 115 kV line, near Bloomfield. Stuck breaker at Gavins. d. Apply fault at Bloomfield 115 kV bus. e. Clear Bloomfield end of line at 5.5 cycles. Leave fault on end of open-ended line from Gavins Point. f. Clear Gavins Point 115 kV bus and fault at 18.0 cycles.	STABLE	STABLE
32	FLT31-1PH	SLG fault on Creighton – Neligh 115 kV line, near Creighton. Stuck breaker at Creighton. d. Apply fault at Creighton 115 kV bus. e. Clear Neligh end of line at 6.5 cycles. Leave fault on open-ended line from Creighton. f. Clear Creighton 115 kV bus and fault at 18.0 cycles.	STABLE	STABLE
33	FLT32-1PH	SLG fault on Gavins Point – Hartington 115 kV line, near Gavins Point. Stuck breaker at Gavins Point. d. Apply fault at Gavins Point 115 kV bus. e. Clear Hartington end of line at 6.5 cycles. Leave fault on open-ended line from Gavins Point. f. Clear Gavins Point 115 kV bus and fault at 18.0 cycles.	STABLE	STABLE
34	FLT33-1PH	SLG fault on Neligh-County Line, near Neligh. Stuck PCB at Neligh. d. Apply fault at Neligh 115 kV bus. e. Clear North Norfolk end of Neligh-CountyLine-BattleCreek-NorthNorfolk 115 kV line at 6.5 cycles. Leave fault on open-ended line. f. Clear Neligh 115 kV bus and fault at 18.0 cycles.	STABLE	STABLE
35	FLT34-1PH	SLG fault on Albion-Genoa 115 kV line near Albion. Stuck PCB at Albion. d. Apply fault on Albion 115 kV bus. e. Clear Genoa end of Albion-Genoa 115 kV line at 6.5 cycles. Leave fault on open-ended line. f. Clear Albion 115 kV bus and fault at 18.0 cycles.	STABLE	STABLE

Cont. No.	Cont. Name	Description	2010 Summer	2010 Winter
36	FLT35-1PH	SLG fault on Kelly – Columbus West 230 kV line. Stuck PCB at Kelly. d. Apply fault on Kelly 230 kV bus. e. Clear Columbus West end of line at 6.0 cycles. Leave fault on open-ended line. f. Clear Kelly 230 kV bus and fault at 14.5 cycles.	STABLE	STABLE
37	FLT36-3PH	3PH fault on Spirit Mound – Manning 115 kV line with prior outage of Gavins Point – Yankton Junction 115 kV. d. Prior Outage: Gavins Point – Yankton Junction 115 kV line e. Apply 3PH fault on Manning115 kV bus. f. Clear fault after 6.5 cycles and trip faulted Spirit Mound – Manning 115 kV line.	STABLE	STABLE
38	FLT37-3PH	3PH fault on Albion – Genoa 115 kV line with prior outage of Petersburg – Neligh 115 kV. e. Prior Outage: Petersburg – Neligh 115 kV line f. Apply 3PH fault on Albion 115 kV bus. g. Clear Albion end of Albion – Genoa 115 kV line in 5.5 cycles. Leave fault on end of line out of Genoa. h. Clear fault after 6.5 cycles and trip faulted Albion – Genoa 115 kV line.	STABLE	STABLE
39	FLT38-3PH	3PH fault on Gavins Point – Bloomfield 115 kV line with prior outage of Neligh – County Line 115 kV. d. Prior Outage: Neligh – County Line 115 kV e. Apply 3PH fault on Bloomfield 115 kV bus. f. Clear fault after 6.5 cycles and trip faulted Gavins Point – Bloomfield 115 kV line.	STABLE	STABLE
40	FLT39-3PH	3PH fault on Albion - Petersburg 115 kV line with prior outage of Neligh – County Line 115 kV. d. Prior Outage: Neligh – County Line 115 kV e. Apply 3PH fault on Petersburg 115 kV bus. f. Clear fault after 6.5 cycles and trip faulted Albion – Petersburg 115 kV line.	STABLE	STABLE

6.5 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 6.

Table 6: LVRT Fault Contingencies

Cont. Name	Description
FLT01-3PH_LVRT	3 phase fault on the GEN-2006-044N (570644) to Neligh (640293) 115kV line, near GEN-2006-044N. a. Apply fault at the GEN-2006-044N 115kVbus. b. Clear fault after 9.0 cycles by tripping the faulted line.
FLT02-3PH_LVRT	3 phase fault on the GEN-2006-044N (570644) to Petersburg (640318) 115kV line, near GEN-2006-044N. a. Apply fault at the GEN-2006-044N 115kVbus. b. Clear fault after 9.0 cycles by tripping the faulted line.

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-2006-044N 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 40.5 MW of wind generation within the balancing authority of Nebraska Public Power District (NPPD) in Boone County, Nebraska, 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-2006-044N is found to be in compliance with FERC Order #661A.

Due to the existing transmission system line capacities near GEN-2006-044N, the Customer's wind facility is limited to a maximum of 34.5MW during the interim operation and may be curtailed to at least 26MW for some prior outage conditions.

The Customer's wind facility must be capable of meeting a 0.997 lagging to 0.950 leading power factor at the POI.

The Customer will also be required to provide security in the amount of $10,000,000 per DISIS-2009-001-1 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-2006-044N interconnection request advances through the Cluster interconnection process as stated in SPP's OASIS posting.

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

Cont. No.	Cont. Name	2010 Summer				2010 Winter			
		Power @ POI	VARS @ POI	Power Factor		Power @ POI	VARS @ POI	Power Factor	
0	No Fault	-39.9	13.8	0.945	LEADING	-39.9	13.2	0.949	LEADING
1	FLT01-3PH	-40.0	9.9	0.971	LEADING	-40.0	2.5	0.998	LEADING
2	FLT02-3PH	-39.9	13.7	0.946	LEADING	-39.9	17.9	0.912	LEADING
3	FLT03-3PH	-40.0	-2.1	0.999	*LAGGING*	-40.0	3.0	0.997	LEADING
4	FLT04-3PH	-39.9	19.3	0.900	LEADING	-39.9	13.6	0.947	LEADING
5	FLT05-3PH	-39.9	14.3	0.941	LEADING	-40.0	13.1	0.950	LEADING
6	FLT6-3PH	-39.9	14.2	0.942	LEADING	-40.0	13.1	0.950	LEADING
7	FLT7-3PH	-39.8	22.2	0.873	LEADING	-39.9	10.8	0.965	LEADING
***8**	**FLT8-3PH**	**-39.8**	**23.3**	**0.863**	**LEADING**	-39.9	15.2	0.934	LEADING
9	FLT9-3PH	-39.9	10.2	0.969	LEADING	-39.9	9.6	0.972	LEADING
10	FLT10-3PH	-39.9	14.7	0.938	LEADING	-39.9	16.8	0.922	LEADING
11	FLT11-3PH	-39.9	14.4	0.941	LEADING	-39.9	13.4	0.948	LEADING
12	FLT12-3PH	-39.9	12.7	0.953	LEADING	-39.9	11.8	0.959	LEADING
13	FLT13-3PH	-40.0	10.9	0.965	LEADING	-39.9	13.0	0.951	LEADING
14	FLT14-3PH	-39.9	13.9	0.944	LEADING	-39.9	13.8	0.945	LEADING
15	FLT15-3PH	-39.9	14.0	0.944	LEADING	-39.9	14.3	0.941	LEADING
16	FLT15-3PH1	-39.9	10.5	0.967	LEADING	-40.0	6.0	0.989	LEADING
17	FLT16-3PH	-39.9	12.4	0.955	LEADING	-39.9	10.4	0.968	LEADING

Cont. No.	Cont. Name	2010 Summer				2010 Winter			
		Power @ POI	VARS @ POI	Power Factor		Power @ POI	VARS @ POI	Power Factor	
18	FLT17-3PH	-39.9	15.4	0.933	LEADING	-39.9	13.4	0.948	LEADING
19	FLT18-3PH	-39.9	13.7	0.946	LEADING	-39.9	11.6	0.960	LEADING
20	FLT19-3PH	-39.9	13.5	0.947	LEADING	-39.9	13.6	0.947	LEADING
21	FLT20-3PH	-39.9	14.0	0.944	LEADING	-40.0	11.4	0.962	LEADING
22	FLT21-3PH	-39.9	12.8	0.952	LEADING	-39.9	12.1	0.957	LEADING
23	FLT22-3PH	-40.0	9.1	0.975	LEADING	-40.0	9.1	0.975	LEADING
24	FLT23-3PH	-39.9	12.7	0.953	LEADING	-39.9	12.0	0.958	LEADING
25	FLT24-3PH	-39.9	14.3	0.941	LEADING	-39.9	13.4	0.948	LEADING
26	FLT25-3PH	-40.0	11.1	0.964	LEADING	-39.9	11.5	0.961	LEADING
27	FLT26-3PH	-39.9	14.2	0.942	LEADING	-39.9	13.4	0.948	LEADING
28	FLT27-3PH	-40.0	11.4	0.962	LEADING	-39.9	11.7	0.960	LEADING
29	FLT28-3PH	-39.9	13.8	0.945	LEADING	-39.9	12.3	0.956	LEADING
30	FLT29-3PH	-40.0	10.0	0.970	LEADING	-39.9	11.7	0.960	LEADING
37	FLT36-3PH	-40.0	9.6	0.972	LEADING	-40.0	7.4	0.983	LEADING
***38**	**FLT37-3PH**	-40.0	8.2	0.980	LEADING	**-40.0**	**-3.2**	**0.997**	***LAGGING***
39	FLT38-3PH	-39.9	20.5	0.889	LEADING	-40.0	2.5	0.998	LEADING
40	FLT39-3PH	-40.0	5.7	0.990	LEADING	-40.0	2.3	0.998	LEADING

* Indicates the least leading and lagging power factors.

APPENDIX B.

STABILITY PLOTS

All plots available on request.