St. Leon Wind Farm Interconnection Evaluation Study

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August 2003

Executive Summary

An Interconnection Evaluation Study (IES) has been performed to determine the transmission facilities necessary to connect a 50, 99 or 198 MW wind farm near St. Leon, Manitoba. The Generator has requested the proposed generation facility be considered a Manitoba Hydro (MH) network resource subject to negotiations with Power Supply. As a network resource, the impacts of scheduling to MH generation and load were evaluated. MH's load and generation are located entirely within the Province of Manitoba. Therefore, the wind generation will not require the need to increase transfer levels on the Manitoba to Ontario, Saskatchewan or U.S. boundaries. This IES determined the impact of the wind generation on the existing MH transmission system by means of steady-state ac and dc power flow analysis, constrained interface analysis, stability analysis, short circuit analysis and voltage quality analysis.

There are two feasible connection points for the wind farm, either the St. Leon 230 kV station bus or the St. Leon 66 kV station bus. Analysis was performed to determine the amount of wind generation that can be connected at either of these locations. The wind farm distribution station is assumed to be a maximum of 1.6 km away from the St. Leon switching station.

For the 66-kV location, approximately 50 MW of generation can be accommodated with a single 66-kV feeder due to thermal limitations of the transmission line. A 99-MW wind farm requires two 66-kV feeders. Due to the rating of the St. Leon 230-66 kV transformer banks, the maximum amount of wind generation that can be connected is 99 MW. An additional step-up transformer bank is required for larger wind farms. Voltage control on each wind turbine is required if the total size of the wind farm exceeds 9 MW. Additional studies are required to determine if voltage control is adequate to prevent interaction with tap changers on the St. Leon transformers and to prevent dynamic voltage instability if the wind farm is greater than 50 MW.

For the 230 kV location, 198 MW of generation can be accommodated with a single transmission line. Voltage control is required on each wind turbine if the total wind farm size exceeds 27 MW. Additional studies are required to determine if voltage control is adequate to prevent dynamic voltage instability if the wind farm is greater than 99 MW.

There are no short circuit concerns or constrained interface concerns for either the St. Leon 66 kV or 230 kV termination locations.

Voltage flicker due to the tower shadow effect, wind turbulence and switching of individual wind mills is not a concern.

Several thermal overloads are identified that require further investigation in an Interconnection Facility Study. A 50 MW wind farm impacts the 110 kV line between Laverendrye and St. Vital (YV5). A 100 MW wind farm impacts the 110 kV line between Cornwallis and Brandon (CB 42) and the 230 kV line between Dorsey and Rosser (D5R) in addition to YV5. A 200 MW wind farm impacts the 110 kV line between Rosser and Inkster (RS51), the 110 kV between Mohawk and St. Vital (XV39) and the 110 kV line between Rosser and Griffin Steel (TR5) in addition to YV5, CB42 and D5R.

The wind turbine’s grid overvoltage capability of 112.5% is exceeded following disturbances that result in temporary or permanent blocking of the HVdc system at Dorsey. The wind turbine must stay connected for temporary overvoltages up to 1.3 p.u. for 200 milliseconds.

The wind turbine’s grid undervoltage capability of 85% is exceeded for local 230 kV stuck-breaker disturbances or local 66 kV disturbances. Local area disturbances must not result in cascade tripping of the wind generation. The wind turbines must be equipped with fault ride through capability.

A detailed evaluation of the capability of the St. Leon ring buses to accommodate the proposed wind generation was not conducted. This study is part of the Interconnection Facilities Studies. For example, if breaker 6 in the 230 kV ring is open for maintenance and there is an inadvertent trip of breaker 3, the output of the wind farm flows into Bank 3 and out of Bank 4. If the wind farm is greater than 93 MW both banks could overload. An operating restriction and reverse power relays on the St. Leon transformers would be required. There are concerns with the rating of current transformers and bus work in the 66 kV ring bus. Extensive modifications may be required if the wind farm is greater than 50 MW.

The approximate costs of the transmission facilities necessary to connect the wind farm to the St. Leon 230 kV and 66 kV station buses were calculated for planning purposes. A more detailed cost estimate will be developed in the Interconnection Facilities Study. The cost to connect a 50, 99 or 198 MW wind farm to the St. Leon 230 kV bus is $2.9 million. The cost to connect a 50 MW wind farm to the St. Leon 66 kV bus is $1.9 million and $3.8 million if the wind farm is 99 MW.

Based on economic and technical considerations, it is preferred to terminate the wind farm on the St. Leon 230 kV station bus rather than the 66 kV station bus. If a commitment to proceed with the project (i.e. either a signed Interconnection & Operating Agreement or Letter Agreement) is made before July 31, 2003 an in-service date of October 31, 2004 is possible for the direct interconnection facilities. If a commitment to proceed is made by February 28, 2004, an in-service date of May 31, 2005 is achievable. In-service dates between Nov. 1 and May 1 are not possible because of outage restrictions at St. Leon. These dates are preliminary and would be confirmed during Interconnection Facility Studies.

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1.0 Introduction

1.1 Background Information

This report documents the results of an Interconnection Evaluation Study for a wind farm near the town of St. Leon, Manitoba. The Generator is proposing to develop a 50 MW, 99 MW or 198 MW wind farm. The proposed in-service date is Dec. 2004.

The Generator has indicated that the wind turbines could be installed in up to 23 sections located in Township-Range: 4-9W, 4-8W, 5-8W and 5-9W. The exact location of the Generator's distribution station has not been determined. For the purpose of this study, it is assumed to be a maximum 1.6 km away from the St. Leon station.

The initial plan for the distribution station is 34.5 kV. Manitoba Hydro's standard distribution voltages are 12.47 kV, 25 kV and 66 kV. MH could be contracted to provide an emergency spare transformer if one of our standard voltages are chosen.

A 230 kV to 66 kV switching station is located at St. Leon. Three 230 kV lines terminate in this station. A 129 km line extends to Dorsey (D14S), a 52 km line terminates at Glenboro (S53G) and a 100 km line terminates at Letellier (S60L). The summer rating of each line is 372 MVA (D14S), 309 MVA (S60L), and 279 MVA (S53G). Three radial 66 kV lines are used to supply loads in the area. Line 51 is 106 km, line 52 is 82 km long and line 79 is 81 km. The summer rating of each line is approximately 64 MVA. Two 230-66 kV 93-MVA transformer banks supply the load. Fig. 1 is a single line diagram showing the existing facilities connected to the St. Leon station.

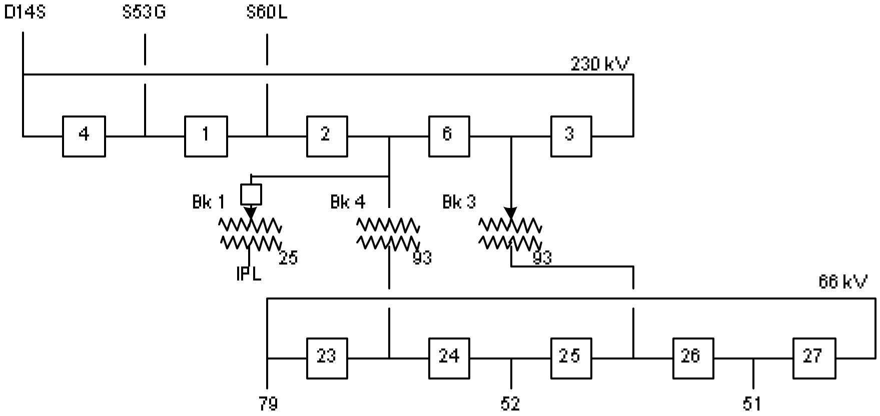

Fig. 1: Existing St. Leon station single line diagram.

There are several options for interconnection of the wind farm to the MH network:

- Tapping a 230 or 66 kV line
- Direct connection to the St. Leon 230 or 66 kV station bus

Tapping a 230 kV or 66 kV line a short distance from the St. Leon station is not desirable for the following reasons:

- The cost to establish a new station is expensive.
- There are no future needs to expand such a station for Manitoba Hydro purposes.
- New generation connected to a networked 230 kV transmission line requires as a minimum that the line be sectionalized (2 circuit breakers) for protection and reliability purposes.
- HVdc reduction logic on line S60L and S53G would require modification.

The most desirable options are to connect the new generation facility to either the 230 kV or 66 kV station buses.

Fig. 2 shows the major interconnection facilities required to connect the wind farm into the 230 kV station bus. One 230 kV circuit breaker within the St. Leon station (and associated equipment) plus a 1.6 km line are required to be installed by MH. The line is assumed to have a 795 MCM ACSR conductor, 100 deg C thermal rating (393 MVA summer, 515 MVA winter rating). A minimum of one motor-operated disconnect is required at the point of interconnection (i.e. high side of Generator's step-up transformer). MH requires visual isolation as well as the ability to automatically isolate the Generation Facility. The Generator must provide a fault interrupting device near the point of interconnection. A 230 kV circuit breaker is indicated in Fig. 2. It is not MH's practice to provide primary protection for Generator's equipment due to liability concerns.

The single 230 kV transmission line is adequate from an operating reserve point of view. The MH network is designed to withstand loss of the largest unit under a single contingency, which today is two 133 MW Limestone units or 266 MW. The system can withstand loss of the largest HVdc valve group under maximum temperature conditions (i.e. greater than 28 deg. C), which corresponds to 500 MW. The probability of this event is ten times lower than loss of the Limestone unit. The single transmission line also assumes no energy delivery penalty during unscheduled outages of the line.

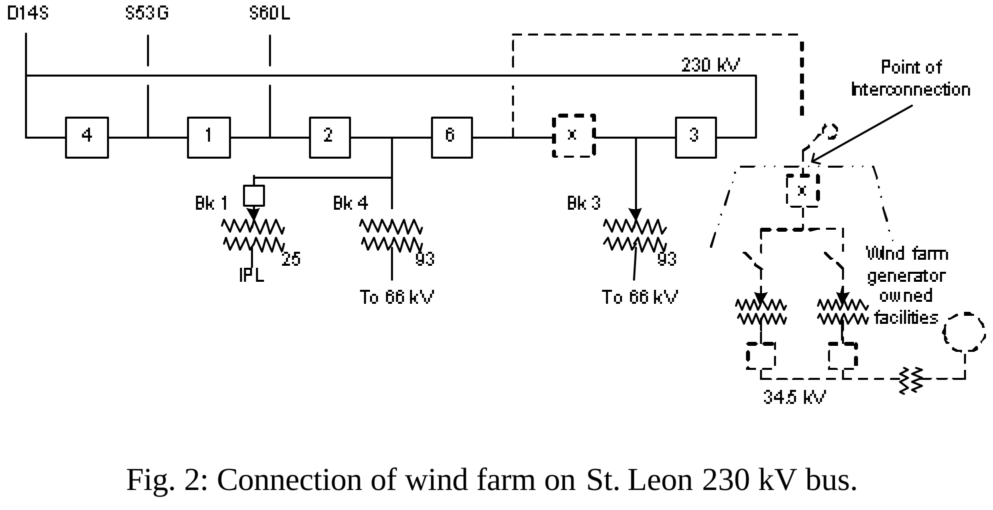

Fig. 2: Connection of wind farm on St. Leon 230 kV bus.

Fig. 3 shows how the wind farm could be integrated into the St. Leon 66 kV station bus. A 50-MW connection requires one 66 kV circuit breaker in the station and a 1.6-km 66-kV line terminated by a high-side breaker. A 99-MW wind farm requires two 66-kV circuit breakers in the station and two 1.6-km 66-kV lines terminated by high-side breakers. The high-side breaker prevents isolation of the wind farm onto MH load for a single breaker failure.

The 66 kV lines are assumed to be 336 MCM ACSR conductor with a 64.3 MVA summer and 84 MVA winter rating (i.e. on 65.1 kV base).

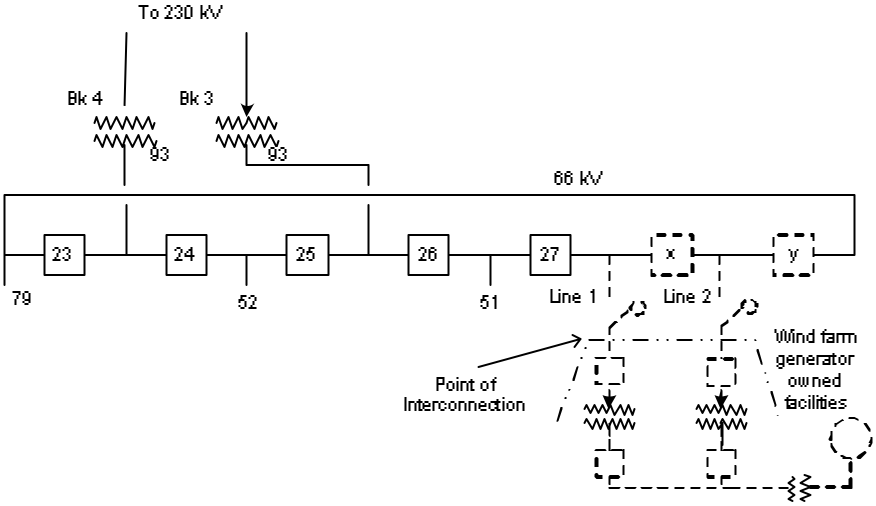

Fig. 3: Connection of wind farm on St. Leon 66 kV bus.

1.2 Objectives

The Interconnection Evaluation Study objectives are to determine:

- the voltage level at point of interconnection,
- facilities required to electrically connect the generator to the MH electrical system
- adequacy of reactive power facilities,
- system reliability limitations (i.e. equipment overloads, voltage violations),
- short circuit impacts (e.g. circuit breaker replacement),
- planning level cost estimates of transmission facilities and an estimate of the lead time required to procure major apparatus.

If the Generator chooses to proceed, the Interconnection Facilities Study phase will:

- address the system reliability limitations,
- determine a good faith cost estimate of all the interconnection facilities,
- determine a good faith construction schedule estimate,
- define the design ratings of the connection equipment,
- satisfy any requirements of the Regional Transmission Authority.

2.0 Wind Turbine Models

2.1 Introduction

The wind turbines proposed by the Generator are the fixed-speed type consisting of a directly grid-coupled squirrel cage induction generator. The Generator proposes using NEG Micon NM72C, 0.6 kV, 1.66 MVA (1.5 MW) wind turbines. The voltage and frequency characteristic of the wind turbines are summarized in Table 1 below:

Table 1: Standard Voltage and Frequency Characteristic of NM72C Wind Turbines

Condition	Wind Turbine Tolerance	Wind Turbine Tolerance
Over–voltage	1.1 pu for 60 s	1.12 pu for 0.1 s
Under–voltage	0.9 pu for 60 s	0.85 pu for 0.1 s
Over–frequency	61 Hz for 0.2 s	
Under–frequency	58 Hz for 0.2 s	

The wind turbines are designed to trip-off if any of the above conditions are violated. Additional equipment can be installed by NEG Micon if, for example, fault ride through capability is required.

Nominal operating wind speed is 16 m/s (33.6 mph) with cut-in and cut-out wind speeds being 5 m/s (8.9 mph) and 24 m/s (55.9 mph). Power output is optimized over the wind speed range of around 16 to 24 m/s. Power output from the turbines is zero (turbines shut down) above the cut-out wind speed of 24 m/s and below the cut-in wind speed of 5 m/s.

The rotor of each wind turbine has three blades which are 72 m in diameter with a total swept area of 4072 m^2 and rated rotor speed of 17.3 rpm. Rotor hub height, which is the distance between the tower footing and the turbine rotor hub, can be between 60 and 80 m. Each turbine is coupled to an ABB manufactured 6-pole induction generator through a gear box mechanism with a 1:70.2 gear ratio. The gearbox is required to convert the slow rotating high torque output power of the wind turbine rotor to the high speed low torque power used for the generator.

2.2 Reactive Power Compensation

There are various reactive power arrangements that can be supplied with the NM72C/1500 turbine. The basic schemes are:

- No-load Power Factor Compensation (PFC)
- Full load PFC
- Dynamic PFC

Reactive power consumption and power factor correction is provided by 600-V capacitors that are supplied with each wind turbine. The 1.66-MVA induction generators absorb 0.42 MVAr reactive power at no load and 0.727 MVAr reactive power at rated output power. Capacitors can be switched in five steps or continuously with the dynamic

PFC option. At 100% generation output the power factor without reactive compensation is 0.9 lagging, with no-load PFC the power factor is 0.981 lagging and with full load PFC the power factor is unity. Table 2 below summarizes the reactive power compensation available from the three basic schemes.

Table 2: NM72C Reactive Power Compensation Options

Step No.	No-Load PFC	Full Load PFC	Dynamic PFC
1	136.2	227	Full range fast acting thyristor switched capacitor banks (available without turbine running)
2	136.2	181.6	
3	90.8	181.6	
4	45.4	90.8	
5	22.7	45.4	
Total kVAr	431.3	726.4	825

The full-load or no-load power factor compensation can be combined with dynamic power factor compensation. The maximum available kVAr capability is 1551.4 kVAr. The machine power factor can be controlled between 0.90 underexcited and 0.88 overexcited with this combination of reactive power compensation.

The Manitoba Hydro connection standard requires that any generation facility providing reactive supply must be able to control the voltage level by adjusting the Machine’s power factor between 0.85 overexcited and 0.90 underexcited. If the generation facility is small enough then reactive supply may not be required. The minimum connection requirement for an induction generator in this case is that sufficient reactive supply must be provided to deliver rated output at unity power factor.

Power flow and stability simulations in this interconnection evaluation study use the full-load PFC arrangement as an initial assumption. This study will determine the adequacy of this type of reactive power compensation.

2.3 Wind Turbine Control Types

Wind turbines are generally designed to yield maximum output at wind speeds between 16 and 24 m/s. Since higher wind speeds are rare, it is not economical to design the turbines to maximize their output at higher wind speeds. In case of higher wind speeds, to prevent damage to the wind turbine, the excess energy in the wind is not harnessed. The present practice is to design all wind turbines with some form of power control.

Wind turbine power control is generally achieved in three ways: blade pitch angle control; passive stall control and active stall control.

Blade Pitch Angle Control: On a blade pitch angle controlled wind turbine the controller is designed to check the power output of the turbine several times per second. When the power output becomes too high an error signal is sent to the blade pitch mechanism which pitches (turns about the vertical axis) the rotor blades slightly out of the wind. The blades are turned back into the wind whenever the wind drops again.

Passive Stall Control: Wind turbines equipped with passive stall control have their blades bolted onto the hub at a fixed angle. The geometry of the blades are designed to ensure that when the wind becomes too high turbulence is created on the side of the rotor which is not facing the wind. This turbulence or “stall” effect prevents the lifting force of the rotor blade from acting on the rotor. Therefore as the wind speed in the area increases, the angle of attack of the rotor blade will increase, until at some point it starts to stall.

Active Stall Control: Active stall is a relatively new technology which combines the advantages of pitch control and passive stall control. It is similar to pitch control in that the wind turbine blades are equipped with a pitch control mechanism. The pitch angle is adjusted slightly and very slowly at higher wind speeds in order to always obtain the correct power level. In order to get fairly large torques at low wind speeds the machines are controlled to pitch their blades. When the machine reaches its rated power and the generator is about to be overloaded, the machines are controlled to pitch their blades in the opposite direction in order to make the blades go into a deeper stall. With active stall the power output can be controlled more accurately than with passive stall. This active stall control system can also adjust for variations in air density and pitches the blades to minimize the effects of dust and insect accumulation on the blades.

The NEG Micon NM72C wind turbines proposed by the Generator are fixed speed types equipped with active stall control. For these fixed-speed active-stall controlled wind turbines, the dynamic response to a grid or system disturbance is mainly governed by the dynamics of the induction generator. The other parts of the wind turbine such as the drive train and blade aerodynamic conversion are not important to model in this case.

2.4 Wind Turbine PSS/E Model Discussion

In order to meet 50, 99 or 198 MW capacity at St. Leon, 33, 66 or 132 individual wind turbines will be installed. Power from the turbines will be collected by a 34.5 kV distribution collector system. For the purpose of stability model development, the generators are assumed connected to the St. Leon bus via one equivalent 0.6/34.5 kV step-up transformer and two parallel 34.5/66 or 34.5/230 kV step-up transformers. All of the reactive compensation is modeled as a lumped capacitor on the 600-V bus.

Figure 4 shows the assumed arrangement at St. Leon for a 99 MW installation connected to the 230-kV bus. This arrangement is used for power flow model development associated with the stability analysis portion of this study.

In the PSS/E power flow, a generator with positive electrical power should be used. To model a single-cage machine, either T” or X” should be set to zero and ZSORCE in the power flow model should be set equal to X’. To model a double-cage machine, a value must be provided for both T” and X” and ZSORCE in the power flow model should be set equal to X”.

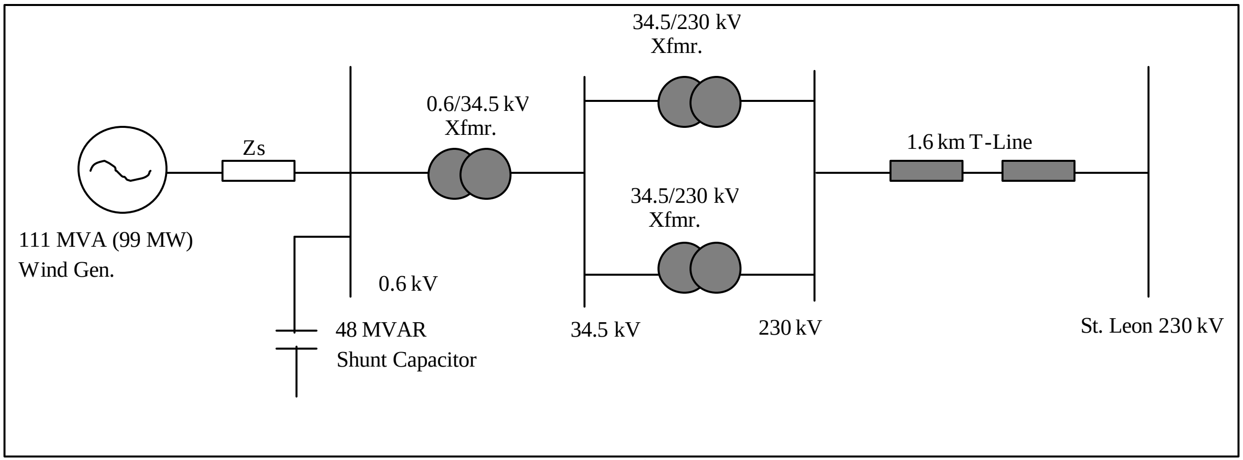

Fig. 4: Assumed connection at St. Leon for stability model development.

Due to the very small time constants in the double cage model, a change in the default PSS/E simulation time step from one-half cycle to one-quarter cycle may be necessary to avoid simulation “blow-up”. As these models are expected to be incorporated into the standard MAPP base cases, modifications to the PSS/E default simulation time step of one-half cycle in order to accommodate the wind turbine models is undesirable. It is therefore recommended that the single cage model be used. Simulations show the difference in damping between the single cage and double cage models, following simulated disturbances, to be negligible.

A standard PSS/E “CIMTR3” single-cage induction generator was applied in the stability model for the wind machine, as shown in Table 3.

Table 3: Wind turbine “CIMTR3” dynamics data

Parameter	**Value (single cage)**
Zsorce	0.222 pu = X’
T’ (sec.)	1.073
T” (sec)	0.0
H (MW-sec./MVA)	5.26
X (pu)	4.18
X’ (pu)	0.222
X’’ (pu)	0.178
Xl (pu)	0.143
E1	1.0
S(E1)	0.17
E2	1.2
S(E2)	0.44
Switch.	0.0
SYN-POW	0
Simulation time step	Default ½ cycle

3.0 Steady-State AC Power Flow Analysis (ACCC)

3.1 Introduction

Steady state power flow analysis was performed to examine the system impact of the proposed wind generation at the following sites:
1) St. Leon 230 kV: 50, 99, 198 MW wind generation
2) St. Leon 66 kV: 50, 99 MW wind generation

The analysis was performed using the AC contingency calculation (ACCC) activity of PSS/E.

A variety of disturbances were considered for the steady state analysis:

- Single element outages in the MH system
- Multi element outages (multi-terminal, common towers) from the MAPP contingency definition for MH

Contingency analysis is conducted on the summer off peak (suop), summer peak (supk) and winter peak (wipk) models for the years 2004 and 2008. ACCC cases investigate sensitivity to Brandon generation, import and export levels, load variations and the impact of a prior outage of the Dorsey to Forbes 500-kV transmission line. The objective of this analysis is to assess the impact of the proposed wind generation on post contingency transmission line and transformer loadings and bus voltages.

All single contingencies on transmission elements rated from 100 kV to 500 kV were studied for the MH area.

3.2 Study Criteria

Steady state power flow analysis monitors voltage and branch loading. Study criteria for both voltage and branch loading were set to match the limits specified in the *MAPP Operating Studies Manual.* Transmission line and transformer loadings were compared with 100% of the PSS/E Rate C (30 minute emergency rating) following a contingency and 100% of Rate A (Continuous normal rating) for system intact conditions as a general study criteria. Bus voltages were monitored for voltages above 110% or below 90 % of the rated voltage following a contingency. Bus voltages were monitored for voltages above 105% or below 95% for system intact conditions.

Facility impacts that are created by the proposed wind addition are monitored. Impacts within the following bounds are considered acceptable:

- A change in voltage of less than +/- 1%
- An increase in facility loading of less than 2% of the facility rating
- Contingency line or transformer overloads not exceeding 100% of Rate C
- Contingency voltage limits within 90 % and 110 % of rated voltage

The above parameters are used as screening parameters to minimize the output included in the ACCC summary report.

The MAPP Design Review Subcommittee (DRS) currently employs a 2% power transfer distribution factor (PTDF) threshold for MAPP member studies, while MISO employs a 3% threshold for MISO system impact studies. The DRS is working with MISO to address the discrepancies especially with respect to MISO member impacts on MAPP facilities. The DRS is also evaluating a change in criteria to account for impacts based on a facility rating PTDF. For ACCC analysis, a 2% PTDF will be used to screen the output, however the 3% MISO criteria will be used for MH facilities.

3.3 Power Flow Model

The base cases were derived from the 2003 series of MAPP load flow models representing the years 2004 and 2008:
2004suop, 2004supk and 2004/2005 wipk
2008suop, 2008supk and 2008/2009 wipk

The specific cases investigated are summarized in Table 4. Wind generation is integrated into the network by rescheduling power to Northern ac generation (i.e. Kettle, Longspruce, and Limestone) connected to Winnipeg (i.e. Dorsey) through HVdc transmission lines. Cases with wind add one to the loadflow numbers (LF #) in Table 4 and a letter designation for the wind location (b-St. Leon 230 kV, c-St. Leon 66 kV).

Table 4: Power Flow Base Case Description

LF #	Yr/ld	MHgen	Wpg Riv.	MH dc	Brandon	MH-US	MH-HO	MH-SP	D602F
1	04suop	4777	590	2670	387	2173	223	301	in
3	04suop	4831	590	3066	0	2177	224	302	in
5	04suop	4766	590	2540	519	2173	224	301	in
7	04suop	3194	590	1192	387	700	223	301	out
9	04suop	1448	119	516	387	-500	0	40	out
11	04supk	5538	590	3350	387	2182	223	213	in
13	04supk	1820	226	752	387	-900	0	58	in
15	04supk	5152	590	3350	0	1800	223	214	in
17	04supk	5670	590	3350	519	2173	223	352	in
19	04supk	3903	590	1864	387	700	224	213	out
21	04wipk	2815	590	824	387	-900	0	47	in
23	08suop	4912	590	2792	387	2175	223	299	in
25	08suop	4966	590	3186	0	2176	223	300	in
27	08suop	4898	590	2660	519	2175	223	300	in
29	08suop	3319	590	1312	387	700	224	300	out
31	08suop	1585	119	656	387	-500	0	60	out
33	08supk	5538	590	3350	387	2175	223	85	in
35	08supk	1951	226	880	387	-900	0	53	in
37	08supk	5152	590	3350	0	1793	223	86	in
39	08supk	5670	590	3350	519	2179	223	214	in
41	08supk	3909	590	1870	387	700	223	85	out
43	08wipk	2903	590	910	387	-900	0	41	in

One of the transmission system tests is to demonstrate that maximum accredited generation can be connected at 70% peak load. Since MH is a winter peaking utility, the 70% peak load case is chosen to be summer peak. Summer peak cases are more limiting than winter cases because of transformer and transmission line thermal ratings.

The generation level in the 2004 and 2008 summer peak cases were adjusted (LF #17 and #39) to the maximum accredited level less 45 MW to meet Manitoba's regulating reserve requirements. MH is delivering firm and non-firm power sales on the tie lines as well as the MAPP reserve obligation. According the MH generator interconnection queue, additional generation is proposed to be connected at Brandon in 2006. As this generator has a higher queue position than St. Leon, it was included in the analysis for sensitivity. Table 4A summarizes the output from each generator in the maximum generation case.

Table 4A: Maximum Accredited Capability of MH Generation

Generation Plant	Accredited Value (MW)	PSS/E summer peak (MW)
Limestone	1348.7	1337.0
Long Spruce	1030.6	1025.0
Kettle	1233.1	1198.6
Jenpeg	138.4	138.4
Kelsey	237.6	237.6
Grand Rapids	480.0	480.0
Pine Falls	91.0	89.6
McArthur Falls	61.2	56.5
Great Falls	138.6	131.6
Seven Sisters	172.7	165.4
Slave Falls	72.0	68.0
Pointe du Bois	78.9	78.8
Brandon	386.5	518.0
Selkirk	145.0	145.0
Total	5614.3	5569.5

3.4 ACCC Results

3.4.1 St. Leon 230 kV connection

The addition of wind results in one new overload for a single contingency. ACCC analysis results of 198 MW wind connection at St Leon 230 kV identified an overloaded line in the 2008 Summer Peak case, 900 MW North flow to MH system (Case #36b). The Brandon Victoria to Rapid City 110 kV line MR11 has a 102.4 % overload following loss of the 230 kV Cornwallis-Reston transmission line (C28R). No new overloads for single contingencies result with 99 MW of wind generation connected.

There are no new overloads for common tower contingencies.

Pre-existing (no wind) overloads have been increased in several cases for single and common tower contingencies. These increases are listed in Tables 5 and 6:

Table 5: St. Leon 230 kV single contingency overload increase

Facility	PTDF (%)	LF Case #	Contingency	Year
Raven Lake BK3	7.2	14b	C28R	2004
	7.3	36b	C28R	2008

Table 6: St. Leon 230 kV site-common tower contingencies

Facility	PTDF (%)	LF Case #	Contingency	Year
Brandon-Victoria (BE3)	2.8	14b	BE1/BE2	2004
	2.8	36b	BE1/BE2	2008

Loss of Y51L overloads Glenboro to Cornwallis (G37C) line to 100.8% in 2004 (case 5) and 101.3% in 2008 (case27). The overloads only occur at maximum Brandon output. The St. Leon 230-kV generation eliminates this overload condition.

3.4.2 St. Leon 66 kV connection

Wind generation up to 99 MW at the St. Leon 66-kV site causes no new overload concerns.

The facilities whose pre-existing (no wind) overloads were increased are listed in Table 7.

Table 7: St Leon 66 kV single contingency overload increase

Facility	PTDF (%)	LF Case #	Contingency	Year
Raven Lake BK3	3.6	14c	C28R	2004
	3.7	36c	C28R	2008

Loss of Y51L overloads Glenboro to Cornwallis (G37C) line to 100.8% in 2004 (case 5) and 101.3% in 2008 (case27). The overloads only occur at maximum Brandon output. The St. Leon 66 kV generation eliminates this overload condition.

3.5 Discussion of Limiting Elements

3.5.1 Brandon-Victoria to Rapid City 110 kV Transmission Line MR11

The overloaded section of the MR11 line from Brandon-Victoria to Rapid City is constructed with 266.8 MCM ACSR conductor and is sagged to 75 degree Celsius. The summer line conductor rating is 70.3 MVA. The restrictive element is a line current transformer (CT) at Brandon Victoria with a rating of 57.2 MVA. A new 114.3 MVA rated CT is scheduled to be installed at Brandon Victoria in the 2003/2004 fiscal year. After the CT is replaced, the line MR11 becomes the limiting element and the indicated overload will be eliminated.

3.5.2 Raven Lake 230-110 kV bank 3

The maximum loading of the Raven Lake transformer (BK3) is 103.3 % following the loss of Cornwallis-Reston 230 kV line C28R in the 2004 supk case with 900 MW import from the U.S. (Case #13).

In order to protect the 110 kV line MR11, the low side of the Raven Lake 230-110 kV transformer bank is set to trip on overcurrent to open the network and alleviate the overload. The inverse time overcurrent relay has a 360 A trip setting or 68.59 MVA at 110 kV. The thermal rating of the transformer is 110 MVA.

These overloads are therefore a non-issue as the transformer bank will trip before line MR11 exceeds its overload rating.

3.5.3 Brandon – Victoria 110 kV line, BE3

The 110 kV lines BE1, BE2 and BE3 are parallel lines connecting the Brandon G.S. to Brandon Victoria. The lines are constructed with 336.4 ACSR conductor and are sagged to 75 degree Celsius. The limiting element is the line itself and not station equipment.

A common tower loss of lines BE1 and BE2 results in an overload of 120.7% on the remaining line in the 2004 SUPK case with 900 import to MH (Case #13). The overload increases to 126.6% in 2008 (Case 35). Wind generation at St. Leon increases the loading on the lines an additional 2.8%. Since the PTDF is less than 3%, this contingency does not require further investigation.

3.6 Conclusions

For the single and multiple contingencies investigated, no violation of post disturbance voltage criteria or thermal loading criteria was caused by the addition of wind generation at either the St. Leon 66-kV bus (99 MW max) or the St. Leon 230-kV bus (198 MW max). The additional power from the wind farm was scheduled to Dorsey.

The St. Leon wind farm reduces loading on the Glenboro to Cornwallis transmission line when Brandon generation is high.

4.0 Steady-State DC Power Flow Analysis (TLTG)

4.1 Introduction

Linear dc powerflow analysis (PSS/E activity TLTG) is used to estimate import or export limits between a defined source and sink. The activity identifies a study system in which generation is increased and an opposing system in which generation is decreased (or load is increased). For this study, the source system or POR is defined as the potential wind site - St. Leon 230 kV or St. Leon 66 kV. The opposing system or POD is defined as various combinations of Manitoba load or combinations of Manitoba generation.

Linear dc powerflows calculate thermal limitations caused by overloaded transmission lines or transformers. The method assumes sufficient reactive power reserves are available to hold voltages constant. This type of analysis confirms point-to-point transmission adequacy by identifying transmission limitations that arise as a result of the increased flows from the proposed wind sites to redispatched generation within Manitoba or due to a Manitoba load increase.

4.2 Study Procedure

To test the adequacy of the transmission to transfer the additional wind generation and to search for worst-case contingencies, transfers between the wind sites and several Manitoba sinks were increased incrementally up to 400 MW for the 230 kV connection and 200 MW for the 66 kV connection. For the St. Leon site, all single and common tower contingency outages within Manitoba and on ties to neighboring utilities were tested.

Buses and branches 110 kV and above are monitored. The purpose is to find a contingency that results in a thermal overload of a transmission line or transformer at each incremental transfer level. Power transfer distribution factors (PTDFs) relate the change in wind generator output to the change in specific line and interface flows. PTDF is sometimes referred to as Transaction Participation Factor (TPF) by MISO. Maximum transfer capabilities are calculated by extrapolating the line flows using the PTDF's and comparing them to specified ratings. Facilities identified in TLTG analysis are considered to be limiting elements if they have a PTDF greater than 3%.

Even though the maximum wind generation that may be connected at a site is only 50, 99 or 198 MW, the analysis was performed up to double the proposed maximum output at each site in order to obtain a view of thermal limitations over a wider range of generation. Wind was considered to have a negative impact on the system if a line or transformer became overloaded (and the PTDF was greater than 3%) at an incremental value of wind generation at or below the following target levels:

- St. Leon - 50, 99 or 198 MW connected at 230 kV
- St. Leon - 50, or 99 MW connected at 66 kV

The four Manitoba sinks included Winnipeg River generation, Manitoba load, Dorsey DC and Grand Rapids generation. The two critical sinks are considered to be Grand Rapids generation and Dorsey DC as these are the AGC plants for Manitoba Hydro that would react to control net MH interchange for unscheduled variation in wind generation.

A number of insoluble contingencies can occur in the TLTG analysis. For the Manitoba area, they usually occur for a contingency that would normally result in a DC reduction. DC reductions are not modeled. These insoluble cases are ignored because it is assumed that the DC reduction will mitigate potential overloads. If a DC reduction does not occur, the problem is an existing base case or contingency overload not affected by the wind addition (i.e. PTDF much less than 3%).

In the process of comparing TLTG and ACCC results, it was found that TLTG did not always find all of the same overloads as ACCC analysis. In reference to PTI PSS/E manuals, knowing that TLTG uses the same linearized network model as PSS/E activity DCLF, PTI support provided the following explanation,

"Activity DCLF provides only approximate power flow solutions. The simplified branch flow equations on which its algorithm is based inherently result in phase angles and branch flows that are different from the ac power flow solution, even when the starting point is a fully solved power flow case. Further, they lead to the assumption that bus voltage magnitudes and line losses remain constant as a branch is placed in- or out-of-service. It has the advantage, though, that it is substantially faster than a full ac power flow solution. Thus, its proper role is that of a screening tool to indicate which cases deserve further attention."

4.3 TLTG Results

4.3.1 St Leon 230 kV Connection-Power scheduled to load and non-AGC plants

For several 2004 summer peak cases, single contingency overloads occurred for incremental generation less than 198 MW but greater than 99 MW. For all 2008 summer peak cases, adding wind generation caused contingency overloads at several locations below targets of 99 MW and 198 MW. The most limiting overloads for 2004 and 2008 are summarized in Table 8.

Table 8: Single Contingency Overloads – non-AGC sinks.

Year	Case	Sink	Incremental MW	Limiting Facility	Single Contingency
2004	13	MH load	105.4	Ridgeway Bk 2	Ridgeway Bk 1
			144.0	Line YV5	Line YH33
			167.6	Line MR11	Line C28R
2004	15	MH load	122.6	Line CB42	Cornwallis Bk 3
2008	35	MH load	28.4	Line YV5	Line YX48
			102.7	Line RS51	Line YX48
			165.0	Line MR11	Line C28R
2008	37	MH load	70.3	Line CB42	Cornwallis Bk3

Several common tower contingency overloads also occurred. The most limiting cases for 2004 and 2008 are summarized in Table 9.

Table 9: Com. Tower Contingency Overloads – non-AGC sinks.

Year	Case	Sink	Incremental MW	Limiting Facility	Common Tower Contingency
2004	13	MH load	119.2 149.6	Line RS51 Line XV39	Lines YX47+YX48 Lines YX47+YX48
2004	15	Wpg Riv	70.6	Line D5R	Lines D13R+D16R
2004	17	Wpg Riv	194.8	Line TR5	Lines TV1+TV2
2008	41	Wpg Riv	149.9	Line TR5	Line TV1+TV2

4.3.2 St Leon 230 kV connection-Power scheduled to AGC plants

No single contingency overloads occurred if the generation was scheduled to Dorsey DC.

If generation was scheduled to Grand Rapids, several single contingency overloads occurred on line MR11 and line CB42 at incremental transfers below 198 MW but above 99 MW. The most limiting overloads for 2004 and 2008 are summarized in Table 10.

Table 10: Single Contingency Overloads – AGC sinks.

Year	Case	Sink	Incremental MW	Limiting Facility	Single Contingency
2004	21	Grd Rap	142.8	Line MR11	Line BN5
2008	37	Grd Rap	118.6	Line CB42	Cornwallis Bk 3
2008	43	Grd Rap	132.5	Line MR11	Line BN5

Several common tower overloads also occurred. The most limiting cases for 2004 and 2008 are summarized in Table 11.

Table 11: Com. Tower Contingency Overloads – AGC sinks.

Year	Case	Sink	Incremental MW	Limiting Facility	Common Tower Contingency
2004	15	Grd Rap	118.5	Line D5R[1]	Lines D13R+D16R
2008	37	Grd Rap	99.3	Line D5R[1]	Lines D13R+D16R

4.3.3 St Leon 66 kV connection-Power scheduled to load and non-AGC plants

There were no limiting overloads produced in the 2004 cases. For all 2008 summer peak cases, single contingency overloads occurred for generation levels below 50 MW and 99 MW. The most limiting cases for 2004 and 2008 are shown in Table 12.

Several common tower overloads also occurred. The most limiting cases for 2004 and 2008 are summarized in Table 13.

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[1] This overload shows up as pre-existing if the TLTG sink subsystem is a non-AGC plant. A manual check of this contingency shows the line is loaded to 97% without wind generation.

Table 12: Single Contingency Overloads – non-AGC sinks.

Year	Case	Sink	Incremental MW	Limiting Facility	Single Contingency
2004	1	any	107.3	St. Leon Bk 3	St. Leon Bk 4
2004	13	MH load	106	Ridgeway Bk 2	Ridgeway Bk 1
			113.3	St. Leon Bk 3	St. Leon Bk 4
2008	23	any	108.6	St. Leon Bk 3	St. Leon Bk 4
2008	35	MH load	28.8	Line YV5	Line YX48
			104	Line RS51	Line YX48
			113	St. Leon Bk 3	St. Leon Bk 4
2008	37	MH load	71.3	Line CB42	Cornwallis Bk 3
			113	St. Leon Bk 3	St. Leon Bk 4

Table 13: Com. Tower Contingency Overloads – non-AGC sinks.

Year	Case	Sink	Incremental MW	Limiting Facility	Common Tower Contingency
2004	15	Wpg Riv	70.6	Line D5R	Lines D13R+D16R

4.3.4 St Leon 66 kV connection-Power scheduled to AGC plants

No single contingency overloads occurred for generation levels below 99 MW.

Several common tower overloads occurred. The most limiting cases for 2004 and 2008 are summarized in Table 14.

Table 14: Com. Tower Contingency Overloads – AGC sinks.

Year	Case	Sink	Incremental MW	Limiting Facility	Common Tower Contingency
2008	37	Grd Rap	99.3	Line D5R	Lines D13R+D16R

4.4 Discussion of Limiting Elements

4.4.1 Laverendrye – St. Vital 110 kV line YV5

Single contingency overloads can occur on 110 kV line YV5 following the loss of 110 kV lines YH33, YX47, YX48 or 230 kV line R23R. The limiting element is the line itself. Line YV5 is already sagged to 100 deg C and has a thermal rating of 110.1 MVA. Line YV5 could be re-conductored to mitigate the overloads.

4.4.2 Cornwallis – Brandon 110 kV line CB42

Single contingency overloads can occur on 110 kV line CB42 following the loss of Cornwallis 230-110 kV transformer bank 3. The limiting elements are risers at Brandon and Cornwallis that have ratings of 120 MVA and 133.5 MVA, respectively. Replacing the risers at Brandon and Cornwallis would increase the thermal capability to 184 MVA, which is the limit of the line. Riser replacement would eliminate overloads.

4.4.3 St. James – Rosser 110 kV line RS51

Single contingency overloads can occur on 110 kV line RS51 following the loss of 110 kV line YX48. The overloads only occur at wind generation levels greater than 99 MW. The limiting element is a CT (ratio 800/5) at St. James, which has a thermal rating of 152.4 MVA. The restrictive portion of the St. James – Inkster line is an underground cable that has a thermal rating of 160 MVA. A minimum rating of 165.3 MVA would be required for a 200 MW wind connection. The Rosser – Inkster portion of the line has a rating of 186.7 MVA and is sagged to 100 deg C. A 198 MW wind connection would require a line rating of 194 MVA. The line could be re-conductored to mitigate this overload.

4.4.4 Raven Lake – Brandon-Victoria 110 kV line MR11

Single contingency overloads can occur on 110 kV line MR11 following the loss of 230 kV line C28R or 110 kV line BN5. The limiting element is the Brandon-Victoria CT limit of 57.2 MVA. Brandon-Victoria line MR11 CT replacement is scheduled for 2003/4, which will eliminate the overloads.

4.4.5 Ridgeway 230-63.5 kV transformer bank

Ridgeway 230-63.5 kV station is a supply to the previously Winnipeg Hydro-owned 63.5 kV system. A contingency overload exists following the loss of the other Ridgeway 230-63.5 kV transformer bank. The limiting elements are the station conductors, which are limited to 123 MVA. The transformers are limited to 125 MVA. A third Ridgeway bank is scheduled for 2007. A 30 minute overload rating will be applied until the third transformer bank is in-service.

4.4.6 Dorsey - Rosser 230 kV line D5R

The 230 kV lines D5R, D13R and D16R are parallel lines connecting Dorsey to Rosser. A common tower loss of lines D13R and D16R results in an overload of line D5R. The limiting elements are the Dorsey risers. If the risers are replaced, the thermal limit would increase from 426.3 MVA to 503.5 MVA (18.1%), which corresponds to the line thermal rating. Line D5R is already sagged to 100 deg C.

4.4.7 Mohawk - St. Vital 110 kV line XV39

Contingency overloads can occur on 110 kV line XV39 following the common tower loss of lines YX47 and YX48. The limiting element is line XV39. Line XV39 is already sagged to 100 deg C and has a thermal rating of 110.1 MVA. The line could be re-conductored to mitigate the overloads.

4.4.8 Rosser – Griffin Steel 110 kV line TR5

Common tower contingency overloads can occur on 110-kV line TR5 following the loss of parallel 110-kV lines TV1 and TV2 from St. Vital to Transcona. The limiting element is the line itself. The line is already sagged to 100 deg C and has a thermal rating of 93.2 MVA. The line could be re-conductored to mitigate the overloads.

4.4.9 St. Leon 230-66 kV transformer bank

Load at St. Leon station is supplied via two 93 MVA 230-66 kV transformer banks. If wind generation is connected to the 66-kV bus, loss of one transformer bank will limit the total amount of generation that can be connected. For 2004 summer off peak loads, the maximum amount of wind that can be connected is 107 MW. Further investigation is required at light loads if this location is selected for a 99 MW wind farm.

4.5 Conclusions

Table 15 summarizes all of the limiting elements for each proposed wind site that require further investigation depending on the selected amount of wind to be connected.

Table 15: Summary of Limiting Elements.

Contingency	Limiting Elements
Overloaded elements due to wind at St. Leon 230	
Single	Line YV5 (>28 MW) Line CB42 (>70 MW) Line RS51 (>103 MW) Line MR11 (>133 MW)
Common Tower	Line D5R (> 71 MW) Line XV39 (>150 MW) Line TR5 (>150 MW)
Overloaded elements due to wind at St. Leon 66	
Single	Line YV5 (>29 MW) Line CB42 (> 71 MW) St. Leon Bk. 3&4 (>99 MW) Line RS51 (>104 MW)
Common Tower	Line D5R (>71 MW)

5.0 Constrained Interface Analysis

5.1 Introduction

Constrained interface analysis is typically used to investigate the impact that long-term firm point-to-point transactions have on constrained interfaces within MAPP and MISO and to determine if there is sufficient non-recallable available transmission capacity to accommodate the request. In this case the Generator has requested the wind generator be considered a MH network resource. The impact of redispatching the wind generator to generation within Manitoba on constrained interfaces is calculated.

5.2 Study Procedure

For each of the wind generation sites, system intact cases are modified to include wind generation. An additional 2004 and 2008 winter peak export case was created, and wind generation was added. Three different powerflows are created for each case at each site, in which the wind generation was scheduled to Grand Rapids, Dorsey DC or Brandon CT generation.

The net change in power flow across a constrained interface is divided by the amount of new generation. This quantity is called the distribution factor (DF). Three different sets of DFs were calculated for each powerflow in order to see any effects of varying the Manitoba Hydro slack bus. Area interchange was enabled in the creation of the pre and post wind generation powerflows.

An IPLAN program was run to compare the flows on MAPP constrained interfaces in the pre and post wind cases. If the DF (incremental loading as a percent of the generation schedule) is greater than 3% and the impact is greater than 1 MW, investigation of long-term non-recallable transmission capacity (NATC) is required.

5.3 Discussion - Results

In all cases, the entire wind transaction stays within Manitoba's boundaries, and therefore does not directly cross any of MAPP's constrained interfaces. Loop flows through Saskatchewan and Ontario do not result, due to phase-shifting transformers being present at Boundary Dam on the Saskatchewan-North Dakota 230 kV interconnection and at Whiteshell on the Manitoba-Ontario 230 kV interconnection.

Some minor loop flow through the U.S. is observed as the wind generation increases flows on G82R and L20D and reduces flows on D602F. The highest increased distribution factors for each site are discussed below. Decreased flow on a constrained path is considered to be a positive impact.

5.3.1 St. Leon 230 kV connection

The highest positive distribution factor for the 198 MW generation addition is 1.3% and occurs for the COOPER_S interface (Nebraska) during the 2004 winter peak case. Since the impact is less than 3%, no additional investigation of NATC is needed.

The MWSI interface (Minnesota) shows a reduction in flows of 3% across its boundary.

5.3.2 St. Leon 66 kV connection

The highest positive distribution factor for the 99 MW generation addition is 1.9% and occurs for the COOPER_S interface during the 2004 winter peak case. Since the impact is less than 3%, no additional investigation of NATC is needed.

The MWSI interface shows a reduction in flows of 3.6% across its boundary.

5.4 Conclusions

Either wind generation site at St. Leon can be redispatched to Manitoba Hydro generation without impacting any MAPP constrained interface.

The addition of wind generation increases flows onto G82R and L20D while reducing flows on D602F. The shift is approximately 3-4% of the wind farm output.

6.0 Short Circuit Analysis

6.1 Introduction

The addition of a wind farm near St. Leon may expose existing facilities to an increase in fault current. Fault analysis has been performed to determine the impact of the wind farm on existing equipment connected to the Manitoba Hydro network.

6.2 Fault Study Model

The study model was based on the System Planning 2003 short circuit model, but included the addition of the proposed wind farm locations in southwestern Manitoba.

Transformer, line and generator impedances are in accordance with the data included in this report. The only variation exists in the sub-transient generator reactance X"d. The value of X"d (0.178 pu) used in the stability model is assumed to be "unsaturated", therefore requiring an assumption to develop a "saturated" impedance for placement in the fault study generator model. This assumption (equal to 85% of the unsaturated impedance) creates a more conservative result and follows existing Manitoba Hydro and industry practices.

6.3 Criteria Used In the Evaluation

Three phase and single-line-ground fault levels were calculated at 10 stations in close proximity to the proposed wind facilities. The results were developed and evaluated under the following criteria:

1. "Flat Classical" analysis was used in all fault calculations. The base kV was then increased to1.05 pu and the fault levels adjusted to better reflect actual system voltages.
2. Only the maximum proposed generation at each site was studied, providing for the highest possible fault level.
3. Station fault levels were directly compared to the lowest rated breaker(s) at a particular location, i.e. an individual breaker is required to interrupt the entire fault kA produced by a "close in" fault. No consideration was given for breaker duty or individual equipment contribution.
4. All busses in the major transmission system were analyzed in their "normal"[2] operating condition.
5. All busses in the sub-transmission system were analyzed in a "minimal networked"[3] operating condition.

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[2] This is the "normal operating" model of the 2003 Manitoba Hydro system; all N/O points in use during non-emergency operation are represented.

[3] "Minimal Networked" fault levels allow for a maximum of two switch closures thus linking as many as three supply stations. This differs from normal switching procedures in which only one closure linking a maximum of two supply stations is permitted. All other N/O points are consistent with normal operation.

6.4 Study Results

The evaluation of circuit breaker capabilities requires the development of a base set of fault levels that *do not* contain any added generation. This reference case can then be used to calculate the percent increase in fault levels associated with the addition of generation at the locations and scenarios detailed above.
A theoretical worst case fault level can be evaluated by placing all sites in service simultaneously. The resulting data can be summarized as follows:

1. All circuit breakers within the scope of this investigation have the capability of interrupting all fault levels produced by this theoretically maximum scenario.
2. Stations closest to the generation source have the highest percent increase in fault level. This increase rapidly declines as distance from the source increases.

6.4.1 St. Leon 230 kV Site (198 MW)

An addition of 198 MW of wind generation at the St. Leon 230 kV site, results in an S-L-G fault increase of 28.65 % at St. Leon station. The levels however are only at 42.60 % of the breaker interrupting rating.

6.4.2 St. Leon 66 kV Site (99 MW)

An addition of 99 MW of wind generation at the St. Leon 66 kV site, results in a 3-phase fault increase of 31.44 % at the St. Leon station. The levels however are only at 37.44 % of the breaker interrupting rating.

6.5 Conclusions

The addition of wind farm generation at either or all of the locations detailed in this study will not raise fault levels in the surrounding area beyond the capabilities of any local circuit breakers.

7.0 Stability Analysis

7.1 Introduction

Transient stability involves major disturbances such as sudden loss of generation, line-switching operations, faults or sudden load changes. Following a disturbance, synchronous machine frequencies undergo transient deviations from synchronous frequency and machine power angles change. The objective of a transient stability study is to determine whether or not the machines will return to synchronous frequency at a new steady-state power angle. Changes in power flows and bus voltages are also a concern. Stability analysis is performed using the Northern MAPP Operating Review Working Group (NMORWG) study package to monitor bus voltages, rotor angles, relay margins, power flows and other system variables during critical disturbances.

7.2 Study Criteria

MAPP has specific voltage criteria for buses during system disturbances. This criteria ensures that power system performance is within NERC guidelines. The default transient voltage criteria within MAPP requires that voltages do not swing below 0.70 per unit or above 1.20 per unit voltage after a disturbance clears. Specific buses defined in the *MAPP Operating Studies Manual* have voltage limits outside of those defined by the MAPP default criteria and were applied in this study.

7.2.1 Grid Requirements – Voltage

Specifications from the wind turbine manufacturer NEG Micon indicate an electrical grid requirement of 112.5% maximum voltage for 0.10 seconds and 85% minimum voltage for 0.10 seconds. Note that these undervoltage limits would be exceeded for close-in single phase stuck breaker faults. At St. Leon the undervoltage limits may also be exceeded for normal clearing close-in 66 kV faults due to the longer clearing time associated with this class of breaker.

Bus voltages within Manitoba are allowed to increase to 1.30 pu for a duration no longer than 200 milliseconds. The overvoltages result following temporary or permanent blocking of the HVdc system at Dorsey.

7.2.2 MP voltage

While the 500-kV Forbes to Chisago (line 601) 3-phase fault case (nbz) is flagged in all cases (with and without wind generation) as an undervoltage at MP's Mahtowa 115-kV bus, the sustained 0.81 pu voltage is above the current MP eastern system limit of 0.80 pu, and therefore acceptable.

7.3 Study Models

The 2002/03 winter and 2003 summer study packages approved by NMORWG were used for winter and summer stability assessment, respectively. They are based on a 2001 MAPP model series, year 2003 cases with updates provided by NMORWG.

One summer off-peak base case with high simultaneous transfer and two winter cases with high MH-US north flow provided the base cases:

Load	Prior outage	power flow case
Summer off-peak	none	cu1-so03aa.uzvV4V4.sav
Winter peak	none	vic-wp02aa.ZNZ0Y4W.sav
Winter off-peak	D602F	dn2-wo02ma.9Pn0Y1W.sav

To compare performance with wind generation, the proposed generation was placed in service as a single net machine at one of two alternative buses with either 198 MW (St. Leon 230 kV connection) or 99 MW (St. Leon 66 kV alternative) output, as shown in Table 16. Offsetting generation changes were made via the MH DC system. Lower generation levels, down to 49.5 MW, were studied at each connection point only when transient performance was unacceptable at the generation levels shown below.

Table 16: Base case power flows - Stability Analysis

Power flow	Wind Alternative	Wind generation (MW)	Major Interface Power Transfers		
			MH-US (MW)	NDEX (MW)	SP-US (MW)
cuw-so03aa.uzvV4V4	off	0	2176	1951	164
wa1-so03aa.uzvV4V4	St Leon 230kV	198	2176	1946	164
wb1-so03aa.uzvV4V4	St Leon 66kV	99	2177	1947	164

For 3-phase fault cases, prior outages were applied to the preceding base cases.

Wind generators proposed for these sites are NEG Micon specification type NM72C. These 600-V induction generators have the following rating: 1.667 MVA; 1.5 MW –j 0.727 MVAr at full-load. Power factor compensation is assumed to be provided by 0.727 MVArs (600 V) of capacitors per machine.

The wind farm is modeled by a single equivalent machine model. Zsource in the power flow model is set to the transient reactance (0.222 pu) for representation as a single-cage induction generator. The loadflow Mbase is set to 220, 110 and 55 MVA for the 198, 99 and 49.5 MW alternatives, respectively. This is the net rating for 132, 66 or 33 generators, respectively.

7.3.1 Disturbance List

Based on past summer off-peak coincident maximum transfer studies, the following limiting disturbances were simulated to assess impact of the wind generation:

ag1	4-cycle SLG 345 kV fault at Lelond Olds on Ft. Thompson line. Stuck breaker. Clear faulted line at 11 cycles.
ei2	Permanent bipole fault on the CU DC line. Both Coal Creek units tripped at 0.28 seconds.
mqs	SLG fault at Sherco unit # 3 with breaker fail 8N28. Trip Sherco unit 3.
nbz	4-cycle 3-phase 500 kV fault at Chisago on Forbes line 601. Cross-trip D602F.

In addition, two classes of local disturbances were simulated to assess performance for each alternative:

i. Single line to ground stuck breaker (slow clearing) fault with system intact.

ii. 3-phase normal clearing fault with a prior line or transformer outage.

To give a fair comparison for the local disturbances, it was assumed the network was modified to accommodate the wind site. The cases were first run with the wind plant off and then with it on, at desired output. The following local disturbances were assessed:

<u>St. Leon 230 kV connection</u>

sa3	5-cycle 3-phase 230 kV fault at St. Leon end of St. Leon - Dorsey line D14S
sb3	5-cycle 3-phase 230 kV fault at St. Leon end of St. Leon - Stanley - Letellier line S60L
scs or scz	16-cycle SLG 230 kV fault at St. Leon on Dorsey line D14S. Stuck breaker R4 and subsequent loss of 230 kV line S53G.
sds or sdz	16-cycle SLG 230 kV fault at St. Leon on Dorsey line D14S. Stuck breaker R3 and subsequent loss of 230-65.1 kV Bank 3.

<u>St. Leon 66 kV connection</u>

se3	8-cycle 3-phase 65.1 kV fault on St. Leon 230-66 kV Bank 3
sa3	5-cycle 3-phase 230 kV fault at St. Leon end of St. Leon - Dorsey line D14S
scs or siz	16-cycle SLG 230 kV fault at St. Leon on Dorsey line D14S. Stuck breaker R4 and subsequent loss of 230 kV line S53G.
sds or sjz	16-cycle SLG 230 kV fault at St. Leon on Dorsey line D14S. Stuck breaker R3 and subsequent loss of 230-65.1 kV Bank 3.

7.4 Discussion - Stability Results

Addition of generation in southwest Manitoba at the proposed wind sites changes the Manitoba-US tie line sharing, resulting in increased south flow on the western ties (G82R and L20D) and reduced south flow on the remaining ties, primarily D602F. This change produces slightly different steady state and transient relay margins on the MH-US ties. With the high south transfer cases studied, this has a beneficial effect, reducing D602F loading, which is generally restrictive at high North Dakota export.

While it is understood the wind site facilities would be equipped with protection from conditions such as over/under-voltage or over/under-frequency, this protection was not modeled in this screening analysis. Similarly, some noted problems could be mitigated through the addition of protection schemes. Determination of potential mitigation schemes was not included in the study scope.

Wind machine power and voltage response figures for notable disturbances are included in Appendix A. Appendix B includes power-voltage curves that are used for voltage stability analysis. Transient voltage response is tabled in Appendix C. The table includes notable minimum and maximum voltage at the noted bus after the fault period, consistent with the MH transient voltage criterion.

7.4.1 St. Leon 230 kV connection

The new St. Leon generators (230 kV connection) generally improve performance of the Canada-US ties for key MAPP disturbances at high export. Minimum relay margins decreased by 1% to 86% on line B10T with the worst disturbance studied (Sherco SLG stuck breaker fault mqs, cases 5 and 6).

Transient voltage rise for a nbz fault (Appendix C - case 8) is within MH voltage criteria but does not meet NEG Micon’s grid requirements. Reducing the size of the wind plant from 198 MW is worse, as it increases the transient overvoltage.

With a line S60L prior outage and 198-MW wind generation, poor wind plant voltage response was noted with a local line D14S 3-phase fault (case 10, fault sa3). St. Leon 230 kV voltage recovery, as shown in Figure A-1, is slow and sustains <u>11% post-disturbance voltage decline</u> at 5 seconds.

A subsequent stability case (68, fault sa3) at 99 MW generation provided acceptable performance, with full voltage recovery. This is shown in Figure A-2.

Performance was unacceptable with a local 230-kV line D14S stuck-breaker fault (case 14 - fault scz). With 198 MW of wind generation connected at St. Leon, this disturbance results in <u>dynamic voltage instability</u> at the wind site, as shown in Figure A-3. This disturbance leaves the St. Leon wind site connected to the grid via 230-kV line S60L. This generation becomes a radial supply into an already heavily loaded point in the network (between Y51L and L20D). Power flow analysis was used to study post-disturbance conditions. A power flow solution could not be reached at 198 MW generation level. It was marginal at 148.5 MW (75% of the target). Using immediate post-disturbance power flow analysis (tap-changers locked), a P-V curve was created as shown in Figure B-1. The wind machine MW, MVAr, shunt capacitor and transformer impedance values were modified to reflect the appropriate number of turbines as net wind-farm generation was varied. Note that generator terminal voltage falls below 0.95 pu at approximately 135 MW output.

A subsequent stability case (case 69, fault sfz) was run at 99 MW generation providing acceptable transient performance. St. Leon 230 kV voltage recovery, as shown in Figure B-4, is slow but returns within 3.7% of pre-disturbance voltage.

7.4.2 St. Leon 66 kV connection

The new St. Leon generators (66 kV connection) generally improve performance of the Canada-US ties for key MAPP disturbances at high export. Minimum relay margins remained at 87% on line B10T with the worst disturbance studied (Sherco SLG stuck breaker fault mqs, cases 5 and 19).

Transient voltage rise for a nbz fault (Appendix C - case 20) is within MH voltage criteria but does not meet NEG Micon's grid requirements. Reducing the size of the wind plant from 99 MW is worse, as it increases the transient overvoltage.

Performance was severely degraded with a local 230 kV line D14S stuck breaker fault (case 24 – fault siz). With 99 MW generation at St. Leon this disturbance results in significant sustained voltage depression at St. Leon, as shown in Figure A-5. St. Leon voltages drop to 0.78 pu, 0.66 pu and 0.34 pu at 5 seconds on the 230 kV, 66 kV and 600-V buses, respectively. This disturbance leaves St. Leon wind site connected to the grid via 230-kV line S60L. This generation becomes a radial supply into an already heavily loaded point in the network (between Y51L and L20D). Power flow analysis was used to study post-disturbance conditions. P-V analysis provided results shown in Figure B-2. Tap-changers were locked to show voltage response before St. Leon 230-66 kV tap-changer action. Generator terminal voltage falls below 0.95 pu at approximately 22 MW and 85 MW output.

A subsequent stability case (case 70, fault siz) was run at 49.5 MW generation providing acceptable transient performance. St. Leon 230 kV voltage recovery is shown in Figure A-6.

Similar but marginally less severe results were noted with 230 kV line D14S stuck-breaker fault (case 25 - fault sjz). St. Leon voltage response is shown in Figure A-7. In this case, line D14S and one St. Leon 230-66 kV bank are opened to clear the fault. Another P-V curve, as described above, is shown in Figure B-3.

A subsequent stability case (case 71, fault sjz) was run at 49.5 MW generation providing acceptable transient performance. St. Leon 230 kV voltage recovery is shown in Figure A-8.

There was steady St. Leon 230-66 kV tap-changer action for 66 kV voltage control with variation in wind generation level. Unlike the other alternatives, this suggests potential voltage control or tap-changer duty issues.

With the prior outage of a St. Leon 230-66 kV transformer and loss of the companion bank (fault se3), this alternative leads to isolation of the wind farm generators onto St. Leon 66 kV load. Since the wind generators do not provide voltage control, this results in 66 kV bus overvoltage at 99 MW (case 23, Figure A-9) or undervoltage at 49.5 MW (case 72, Figure A-10) plant capacity.

7.5 Conclusions

The addition of wind generation at St. Leon results in increased south flow on the western ties (G82R and L20D) and reduced south flow on the remaining ties, primarily D602F. This has the beneficial effect of reducing D602F loading which can be limiting when exports out of North Dakota are high.

7.5.1 St. Leon 230 kV connection

The wind turbine manufacturer's grid overvoltage criterion was exceeded for a Chisago 500-kV line 601 disturbance at all proposed plant sizes. Resolution of this issue must be pursued with NEG Micon.

Under studied summer simultaneous export conditions, dynamic voltage instability was noted for a local 230-kV stuck-breaker fault (on line D14S) at 198 MW wind generation.

At 198 MW generation there also was excessive (11%) voltage decline at St. Leon 230-kV for a local 3-phase 230-kV fault on line D14S with the prior outage of 230-kV line S60L.

Transient performance was acceptable based on MH criteria at 99 MW wind generation.

7.5.2 St. Leon 66 kV connection

The wind turbine manufacturer's grid overvoltage criterion was exceeded for a Chisago 500-kV line 601 disturbance at both proposed plant sizes. Resolution of this issue must be pursued with NEG Micon.

With the prior outage of a St. Leon 230-66 kV transformer and loss of the companion bank, this alternative leads to isolation of the wind farm generators onto St. Leon 66-kV load. Since the wind generators do not provide voltage control, the MH 66-kV St. Leon load would sustain uncontrolled over or undervoltage, based on wind generation versus local load level.

Under studied summer simultaneous export conditions, minimum transient voltage at St. Leon was unacceptable for local 230 kV stuck breaker faults (on line D14S) at 99 MW wind generation. This was confirmed with immediate post-disturbance power flow analysis. Transient performance was acceptable at 49.5 MW wind generation.

The St. Leon 230-66 kV tap-changer action resulting from variation in wind generation levels suggested potential voltage control or tap-changer duty issues with this alternative.

8.0 Voltage Quality Analysis

8.1 Introduction

There are several types of fluctuations which can affect the voltage quality due to wind power.

1) Tower shadow effect (periodic, f ˜ 1-2 Hz)
2) Wind turbulence (stochastic, average frequency $f < 0.1$ Hz)
3) Switching of windmills (single events per hour)

These phenomena, as well as others such as wind vertical gradients, contribute to voltage fluctuations or flicker.

The tower shadow effect is caused by the wind turbine blades periodical passing the wind mill tower three times a cycle for three blade turbines, such as the NEG MICON NM72C/1500. This results in a dip in the mechanical torque at each passing, which is transferred to the generator shaft and subsequently seen as a dip in the output voltage.

Voltage fluctuations caused by wind turbulence are due to the stochastic as well as gusty impact of the wind on the turbine.

Windmill switching gives rise to voltage dips in the grid each time it happens and can occur several times per hour.

Flicker is defined as an impression of unsteadiness of visual sensation induced by light stimulus whose luminance or spectral distribution fluctuates with time. This may be caused by voltage variations. Applying a flicker meter, a ten-minute time-series of measured or simulated voltage variations can be transformed into a short-term flicker value, P_{st}. A P_{st} of 1.0 corresponds to the 'threshold of flicker irritation' for rectangular voltage changes. The long term value, P_{lt} corresponds to a period of 2 hours, calculated from a sequence of P_{st} values:

$$P_{lt} = \left(\sum_{i=1}^{12} \frac{P_{st,i}^{3}}{12} \right)^{1/3} \qquad (1)$$

Flicker may be caused both by the continuous and switching operations, such as start-ups, of a wind turbine.

The emission of flicker from a wind turbine during continuous operation is adequately described by its flicker coefficient. The flicker coefficient is a normalized measure of the flicker emission from a wind turbine.

Measurements show that the flicker coefficient for a given turbine is a function of the wind speed at hub-height of the wind turbine, and the network impedance phase angle of the electric network.

It has been shown that the long-term flicker emission (P_{lt}) from a wind turbine during continuous operation is equal to the short-term flicker emission (P_{st}).

The procedure for assessing flicker emission due to switching operations assumes that each wind turbine is characterized by a flicker step factor $k_f(?_f)$, being a normalized measure of the flicker emission due to a single worst-case switching operation.

The start-up of a wind turbine may cause a sudden reduction of the voltage followed by a voltage recovery after a few seconds. Wind turbines are characterized by a voltage change factor $k_u(?_f)$, and this may be used to calculate the expected voltage dip.

8.2 Study Criteria

Flicker planning levels are used by Manitoba Hydro for planning purposes and are useful for evaluating the cumulative impact of all fluctuating loads connected to the system. The levels are specified by the utility based on field measurement, historical experience and industry practice. Table 17 lists the flicker limits used for planning new or evaluating existing installations:

Table 17: Flicker Limits.

System Voltage (U_s)	**P_{st}**	**P_{lt}**
$U_s > 35$ kV	0.8	0.6

Industry standards state that the flicker levels shall be at or below the planning levels, 99% of the time, with a minimum assessment period of 1 week.

Also, starting multiple motors may appear to generate periodic fluctuations on the electrical system when each individual motor is started several times within a given time period. To limit the potential of a flicker problem, Manitoba Hydro requires that individual loads or sources do not introduce fluctuations, at their point of interconnection, above the limits given in Table 17. The purpose of these limits is to ensure that cumulative system flicker levels never exceed the threshold of irritation (i.e. $P_{st}=1.0$).

Dynamic voltage fluctuations are usually caused by motor starting, however, loss of a wind turbine due to excessive wind can cause a brief voltage fluctuation. Dynamic voltage restrictions that are being used by MH are based on IEC Standard 1000-3-7 table 8. The restrictions are repeated in Table 18.

Table 18: Dynamic voltage fluctuation limits (System Voltage 35 kV and greater)

Voltage Change	Permissible Number of Dynamic Events
<2.0%	10 per hour
2.0 – 2.4 %	Twice per hour
2.5 – 2.9 %	Once per hour
3.0 – 3.4 %	Once every two hours
3.5 – 3.9 %	Once every four hours
4.0 – 4.9 %	Once per day
> 5%	Not allowed

8.3 Procedure for Assessment of Voltage Quality

The following procedure is based on IEC 61400-21, “Measurement and Assessment of Power Quality Characteristics of grid Connected Wind Turbines”.

8.3.1 Voltage Flicker During Continuous Operation

The 99th percentile flicker emission from a single wind turbine during continuous operation is estimated by applying equation 2 below:

$$P_{st} = P_{lt} = c(y_k, n_a)\cdot\frac{S_n}{S_k} \qquad (2)$$

where

$c(y_k, n_a)$ is the flicker coefficient of the wind turbine for the given network impedance phase angle, y_k at the PCC, and for the given annual average wind speed, n_a at hub-height of the wind turbine at the site;

S_n is the rated apparent power of the wind turbine;

S_k is the short-circuit apparent power at the PCC.

In the case where more then one wind turbine is connected to the PCC, the flicker emission can be estimated from equation 3 below:

$$P_{st}\Sigma = P_{lt}\Sigma = \frac{1}{S_k}\cdot\sqrt{\sum_{i=1}^{N_{wt}}\left(c_i(y_k, n_a)\cdot S_{n,i}\right)^2} \qquad (3)$$

where

$c_i(y_k, n_a)$ is the flicker coefficient of the individual wind turbine;

$S_{n,i}$ is the rated apparent power of the individual wind turbine;

N_{wt} is the number of wind turbines connected to the PCC.

Equation 3 assumes that the maximum power levels between wind turbines are uncorrelated. Under special conditions, however, wind turbines in a farm may ‘synchronize’, causing power fluctuations to coincide. Equation 3 would then underestimate the flicker emission.

8.3.2 Voltage Flicker During Switching Operations

The flicker emission due to switching operations of a single wind turbine shall be estimated by applying equations 4 and 5 below.

$$P_{st} = 18 \cdot N_{10}^{.31} \cdot k_f(y_k) \cdot \frac{S_n}{S_k} \qquad (4)$$

$$P_{lt} = 8 \cdot N_{120}^{.31} \cdot k_f(y_k) \cdot \frac{S_n}{S_k} \qquad (5)$$

where

$k_f(y_k)$ is the flicker step factor of the wind turbine for the given y_k at the PCC.

In the case where more than one wind turbine is connected to the PCC, the flicker emission from the sum of them can be estimated from equation 6 and 7 below.

$$P_{st}\Sigma = \frac{18}{S_k} \cdot \left(\sum_{i=1}^{N_{wt}} N_{10,i} \cdot (k_{f,i}(y_k) \cdot S_{n,i})^{3.2}\right)^{.31} \qquad (6)$$

$$P_{lt}\Sigma = \frac{8}{S_k} \cdot \left(\sum_{i=1}^{N_{wt}} N_{120,i} \cdot (k_{f,i}(y_k) \cdot S_{n,i})^{3.2}\right)^{.31} \qquad (7)$$

where

$N_{10,i}$ and $N_{120,\mathrm{i}}$ are the number of switching operations of the individual wind turbines within a 10 min and 2 h period;

$k_{f,i}(y_k)$ is the flicker step factor of the individual wind turbine;

$S_{n,i}$ is the rated power of the individual wind turbine.

8.3.3 Voltage Fluctuations

The relative voltage change due to a switching operation of a single wind turbine is estimated by applying equation 8 below.

$$d = 100 \cdot k_u(y_k) \cdot \frac{S_n}{S_k} \tag{8}$$

where

d is the relative voltage change in %;

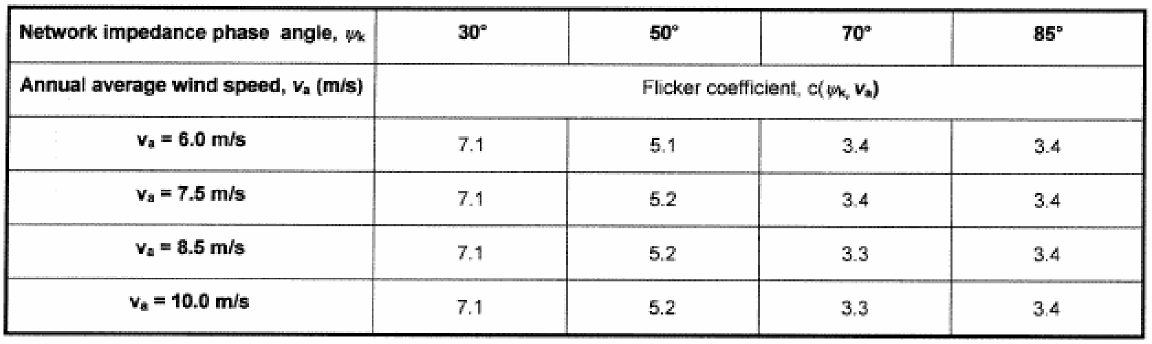
$k_u(y_k)$ is the voltage change factor of the wind turbine for the y_k given at the PCC.

In cases where more than one wind turbine is connected to the PCC, it is not likely that even two of them will perform switching operations at the same time. Therefore, no summation effects need to be taken into account to assess the relative voltage change of a wind turbine installation according to the IEC standard.

8.4 Wind Turbine Voltage Quality Data

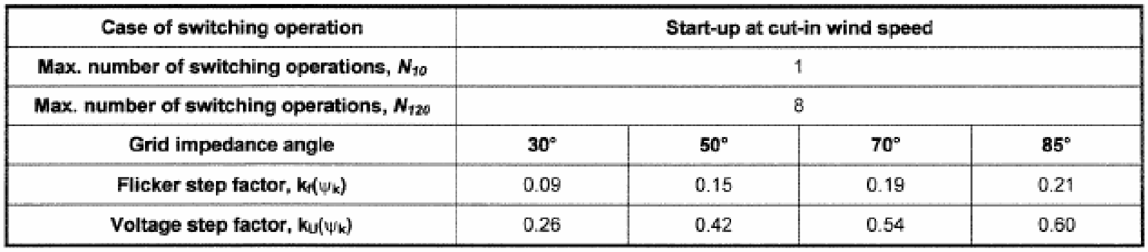
The following data was submitted by NEG MICON on the NM72C/1500 according to IEC 61400-21 for continuous and switching operations.

Table 19: Flicker coefficients for continuous operation.

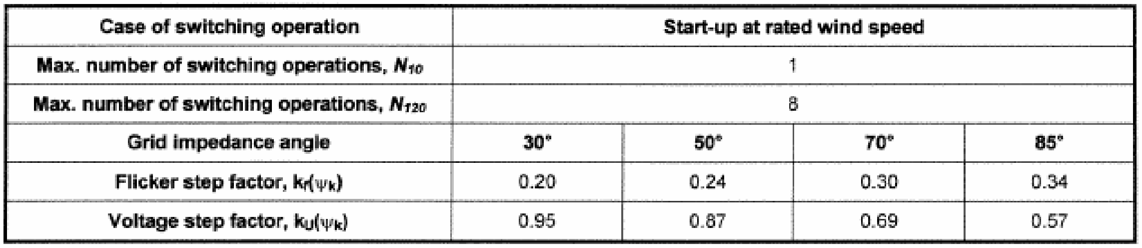


Network impedance phase angle, ψ_k	**30°**	**50°**	**70°**	**85°**
Annual average wind speed, v_a (m/s)	Flicker coefficient, $c(\psi_k, v_a)$			
v_a = 6.0 m/s	7.1	5.1	3.4	3.4
v_a = 7.5 m/s	7.1	5.2	3.4	3.4
v_a = 8.5 m/s	7.1	5.2	3.3	3.4
v_a = 10.0 m/s	7.1	5.2	3.3	3.4

Table 20: Start-up at cut-in wind speed.



Case of switching operation	**Start-up at cut-in wind speed**			
Max. number of switching operations, N_{10}	1			
Max. number of switching operations, N_{120}	8			
Grid impedance angle	**30°**	**50°**	**70°**	**85°**
Flicker step factor, $k_f(\psi_k)$	0.09	0.15	0.19	0.21
Voltage step factor, $k_U(\psi_k)$	0.26	0.42	0.54	0.60



Case of switching operation	Start-up at rated wind speed			
Max. number of switching operations, N_{10}	1			
Max. number of switching operations, N_{120}	8			
Grid impedance angle	30°	50°	70°	85°
Flicker step factor, $k_f(\psi_k)$	0.20	0.24	0.30	0.34
Voltage step factor, $k_U(\psi_k)$	0.95	0.87	0.69	0.57

8.5 Calculations of Voltage Quality Impact

The P_{st} and P_{lt} for continuous and switching operations for an individual wind generator turbine and for the proposed wind farms is calculated below and summarized in Table 23 and 25. A strong system refers to normal operation conditions and weak means that there is a prior outage of a single transmission line or transformer.

8.5.1 St. Leon 230 kV, 198 MW, 132 Wind Generator Turbines

Table 22: Fault Levels at St. Leon 230 kV.

System	Strong	Weak
Short Circuit MVA	2214.8	1376.7
X/R (degrees)	83.7	83.88

Table 23: Calculation of P_{st} and P_{lt} for 132 Wind Generator Turbines at St. Leon 230 kV.

System	Pst=Plt (Continuous)	Pst (Switching)		Plt (Switching)		relative change, d %	
		Start-up at cut-in wind speed	Start-up at rated wind speed	Start-up at cut-in wind speed	Start-up at rated wind speed	Start-up at cut-in wind speed	Start-up at rated wind speed
Strong	0.0294	0.013	0.021	0.011	0.0178	0.0452	0.0429
Weak	0.0473	0.021	0.0338	0.0178	0.0286	0.0726	0.069

8.5.2 St. Leon 66 kV, 99 MW, 66 Wind Generator Turbines

Table 24: Fault Levels at St. Leon 66 kV.

System	Strong	Weak
Short Circuit MVA	768.7	463.6
X/R (degrees)	86.8	87.4

Table 25: Calculation of P_{st} and P_{lt} for 66 Wind Generator Turbines at St. Leon 66 kV.

System	Pst=Plt (Continuous)	Pst (Switching)		Plt (Switching)		relative change, d %	
		Start-up at cut-in wind speed	Start-up at rated wind speed	Start-up at cut-in wind speed	Start-up at rated wind speed	Start-up at cut-in wind speed	Start-up at rated wind speed
Strong	0.0599	0.0303	0.0489	0.0256	0.0414	0.13	0.1236
Weak	0.0993	0.0502	0.081	0.0425	0.0686	0.2157	0.2049

8.5.3 Worst Case Analysis of $P_{st}=P_{lt}$ for Continuous Operation

There is a possibility of the wind turbines operating in synchronism and producing power fluctuations. The P_{st} values for this scenario are calculated for each site and are given in Table 26. The P_{lt} criterion of 0.6 is violated at St. Leon 66 kV during the worst case prior outage condition.

Table 26: Calculation of Worst Case P_{st} and P_{lt}.

System	St. Leon, 230 kV, 198 MW	St. Leon, 66 kV, 99MW
Strong	0.3432	0.4884
Weak	0.5412	0.792

8.6 Voltage Fluctuation Due to Loss of Plant

The worst case estimate of voltage fluctuation (? V) for loss of plant, due to excessive wind, frequency, voltage or temperature for example, can be approximated by equation (9). This analysis does not consider the effects of capacitor switching.

$$\Delta V \approx \frac{MW}{MVA_{SC}} \tag{9}$$

Table 27: Calculation of Worst Case Voltage Fluctuation (? V).

Location	kV	MW	MVA$_{SC}$	?V %	MW	MVA$_{SC}$	?V %
St. Leon	230	198	2215	8.9	99	2215	4.5
			1377	14.4		1377	7.2
St. Leon	66	99	769	12.9	50	769	6.5
			464	21.3		464	10.8

Assuming that there will be at least 6 switching operations per hour in the worst case (i.e. rough average given N_{10} is 1 and N_{120} is 8), the voltage fluctuation changes calculated in Table 27 exceed the MH dynamic voltage fluctuation criteria of 2%. The relative voltage change *d*, given in previous tables, gives a much more conservative estimate.

Equation (9) will be used to establish a voltage control criteria for new generation. If loss of plant during worst case prior outage condition results in a voltage change of 2% or less, the generator does not need to have the ability to control voltage. For St. Leon 230 kV, a wind farm larger than 27 MW (0.02*1377) requires voltage control capability. For St. Leon 66 kV, a wind farm greater than 9 MW (0.02*464) requires voltage control capability.

8.6.1 Overvoltage after Loss of Plant Considering Capacitor Switching

The previous section indicated large overvoltages are possible following loss of the wind farm. Power flow calculations are made to determine the impact of switching the power factor correction capacitors. Three cases are analyzed. Case 1 assumes that all the capacitors on the 600-V bus are tripped off with the wind generation. Case 2 assumes that all the capacitors remain on the 600-V bus after the wind generation is disconnected. Case 3 assumes half the capacitors are tripped off with the wind turbines. The voltage fluctuation at the high voltage point of connection is calculated for each case and is summarized in Table 28.

Table 28: Change in voltage following loss of wind generation plant.

Location	kV	MW	?V1 %	?V2 %	?V3 %
St. Leon	230	198	0.60%	5.70%	2.80%
		99	0.48%	2.80%	1.60%
St. Leon	66	99	1.52%	8.90%	4.82%
		50	0.80%	4.20%	2.40%

Table 28 demonstrates that the power factor correction capacitors need to be tripped off simultaneously with the wind generation in order to prevent large voltage fluctuations. If the capacitors are not switched instantaneously off with the wind generation, then fast voltage control will be needed.

St. Leon is expected to be sensitive to voltage fluctuations because of the large number of customers connected nearby.

8.7 Conclusions

Based on the application of IEC 61400-21 for the purpose of determining the voltage impact due to the grid connection of wind turbine generation, it was found that the proposed sites could be installed without a significant impact on flicker levels. The standard assumes that since the wind turbines are not located in exactly the same place they will not experience the same wind-speeds on the rotor disks. The power fluctuations and the flicker of two or more wind turbines are expected to be uncorrelated stochastic noise.

The P_{st} is well within MH limits for each site for continuous and switching operations.

The P_{lt} is within criteria for each site for normal switching operations. The only possible violation is under the worst case analysis of continuous operation ($P_{st}=P_{lt}$), where all the turbines are synchronized. The limit of 0.6 for P_{lt} is exceeded with a weak system at St. Leon 66 kV. There are no violations of P_{st} or P_{lt} for the St. Leon 230-kV wind farm.

The relative voltage change, *d*, due to switching of a single wind turbine is well within MH limits due to the low magnitude and infrequent occurrence of switching events.

Major impacts on the voltage quality, based on IEC 61400-21 are not a problem due to the strong system strength at each site and the low flicker coefficients of the wind turbines. Therefore, no voltage control device is required for flicker mitigation at the proposed wind farm sites.

The impact on voltage due to loss of plant and capacitor switching is a concern. The power factor correction capacitors must switch off at the same instant as the wind turbine. Voltage control is required on wind farms connected to the St. Leon 230 kV bus if they are larger than 27 MW based on a maximum 2% voltage change criterion for plant loss. Wind farms larger than 9 MW connected to the St. Leon 66 kV bus require voltage control.

9.0 Transmission Facility Costs

9.1 Introduction

The transmission facility costs to connect the wind farm to the St. Leon 230 kV and 66 kV station buses are calculated for planning purposes. Typical unit costs for equipment are used. A more detailed good faith cost estimate will be developed if the study proceeds to the Interconnection Facility Study phase.

9.2 Costs to Connect to St. Leon 230 kV Station

Table 29 summarizes the planning level cost estimate for connecting to the St. Leon 230 kV station. The connection costs are the same for a 50 MW, 99 MW or 198 MW wind farm.

Table 29 St. Leon 230 kV Station Cost Estimate

Item	Cost
Apparatus (CB, CTs, CVTs, disconnects)	$406,997.00
Steel Structures	$73,350.00
Communication	$666,100.00
Protection, SCADA	$166,672.00
Design, construction, commissioning	$514,830.00
Transmission line	$400,000.00
Contingency	$668,385.00
Total	**$2,896,334.00**

The following assumptions have been made in the above estimate:

- A 230 kV wood pole line is required,
- A 230 kV motor operated disconnect is required,
- 4 CVTs and 3 CTs will be installed,
- A 230 kV circuit breaker will be installed,
- 230 kV maintenance disconnects will be provided,
- 6 columns, 5 girders, 15 foundations and all assorted bus hardware and apparatus will be installed,
- Line protection will be installed: dual protection system, digital current differential protection, includes breaker fail,
- Communication will be installed: dual system with fiber as primary and microwave secondary,
- Metering in the wind farm station has not been included,
- No property costs for construction of the 230 kV line are considered,
- No environmental costs have been considered-assumed covered in wind farm licensing,
- No overtime has been estimated,
- No cost has been estimated to mitigate system reliability limitations.

9.3 Costs to Connect to the St. Leon 66 kV bus

Table 30 summarizes the planning level cost estimate for connecting to the St. Leon 66 kV station. The connection costs are for a 50 MW wind farm. The cost of a 99 MW wind farm is double because two terminations are required.

Table 29 St. Leon 66 kV Station Cost Estimate

Item	Cost
Apparatus (CB, CTs, CVTs, disconnects)	$42,000.00
Steel Structures	$148,714.00
Communication	$666,100.00
Protection, SCADA	$166,672.00
Design, construction, commissioning	$514,830.00
Transmission line	$160,000.00
Contingency	$445,100.00
Total	**$1,928,767.00**

The following assumptions have been made in the above estimate:

- A 66 kV wood pole line is required,
- A 66 kV selector switch is required,
- 4 CVTs and 3 CTs will be installed,
- A 66 kV circuit breaker will be installed,
- 66 kV maintenance disconnects will be provided,
- 2 columns, 1 girders, 5 foundations and all assorted bus hardware and apparatus will be installed,
- Line protection will be installed: dual protection system, digital current differential protection, includes breaker fail,
- Communication will be installed: dual system with fiber as primary and microwave secondary,
- Metering in the wind farm station has not been included,
- No property costs for construction of the 66 kV line are considered,
- No environmental costs have been considered-assumed covered in wind farm licensing,
- No overtime has been estimated,
- No cost has been estimated to mitigate system reliability limitations.
- A 336 ACSR conductor is adequate for the loading requirements. Because this is a severe ice area, the use of larger conductors, such as 477 ACSR, is banned. Further investigation would be required to design an appropriate 66 kV line.

The cost to terminate a 50 MW wind farm in the 66 kV St. Leon ring bus is $1.9 million. The price doubles for a 99 MW wind farm. It is more economic to connect a wind farm larger than 50 MW in the 230 kV St. Leon bus. There are concerns with the ability of the 66 kV ring bus to accommodate the proposed generation. It is possible that a large portion of the ring bus would require reconductoring or a number of current transformers may require replacement. In addition, there are concerns with the feasibility of a 66 kV transmission line in this area of the province for the proposed size of wind farm. The 66 kV St. Leon bus is not a viable option for a 50 MW or 99 MW wind farm.

9.4 High Level Schedule

Once a commitment is made to proceed by the Generator, MH requires approximately 1 month to order major apparatus, 12 months for delivery, 2 months to install and commission. If a commitment to proceed is made on July 31, 2003, the earliest in-service date possible is October 31, 2004. Sole sourcing of critical apparatus can reduce the lead time but can increase the apparatus cost.

Bus modifications within the St. Leon station will require transformer outages. Outages for construction are not permissible from November 1 to approximately March 31 depending on weather. If a commitment to proceed with the project is made between August 31, 2003 and February 28, 2004, the earliest possible in-service date is May 31, 2005

Appendix A
Stability Analysis Figures

St Leon 230 kV connection alternative

Figure A1 Comparison - Case 9 (no wind) vs 10 (198 MW wind)
Prior outage of 230 kV line S60L
3-phase fault on 230 kV line D14S (sa3)

Figure A2 - Case 68 (99 MW wind)
Prior outage of 230 kV line S60L
3-phase fault on 230 kV line D14S (sa3)

Figure A3 Comparison - Case 13 (no wind) vs 14 (198 MW wind)
SLG stuck breaker fault on 230 kV line D14S (scs & scz)

Figure A4 - Case 69 (99 MW wind)
SLG stuck breaker fault on 230 kV line D14S (sfz)

St Leon 66 kV connection alternative

Figure A5 Comparison - Case 13 (no wind) vs 24 (99 MW wind)
SLG stuck breaker fault on 230 kV line D14S (scs & siz)

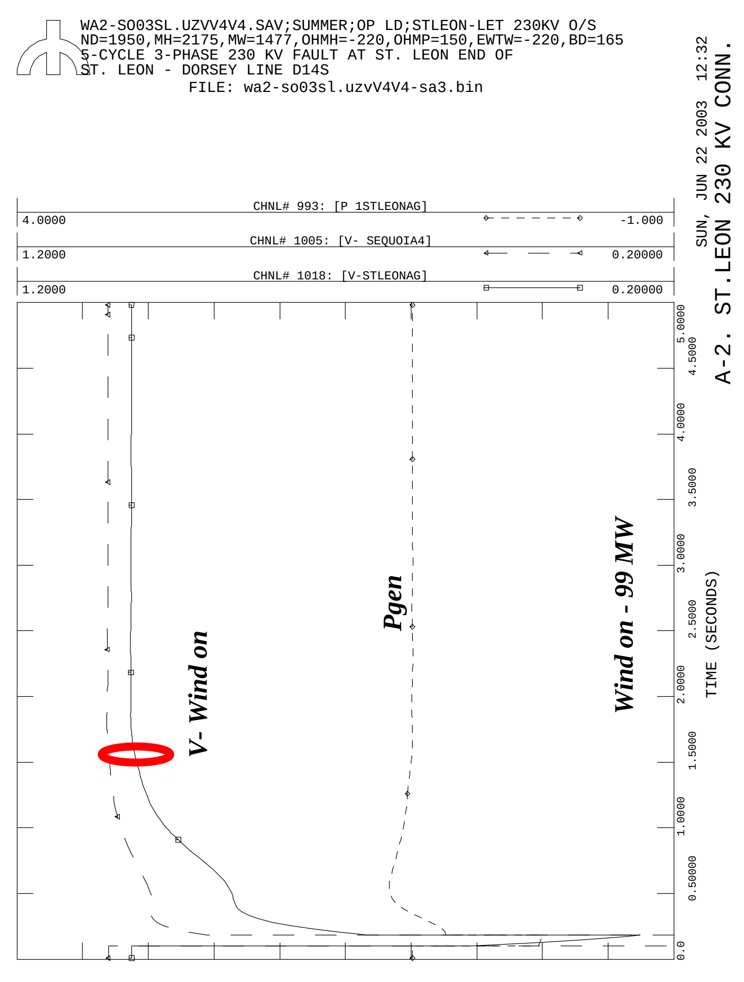
Figure A6 - Case 70 (49.5 MW wind)
SLG stuck breaker fault on 230 kV line D14S (siz)

Figure A7 Comparison - Case 15 (no wind) vs 25 (99 MW wind)
SLG stuck breaker fault on 230 kV line D14S (sds & sjz)

Figure A8 - Case 71 (49.5 MW wind)
SLG stuck breaker fault on 230 kV line D14S (sjz)

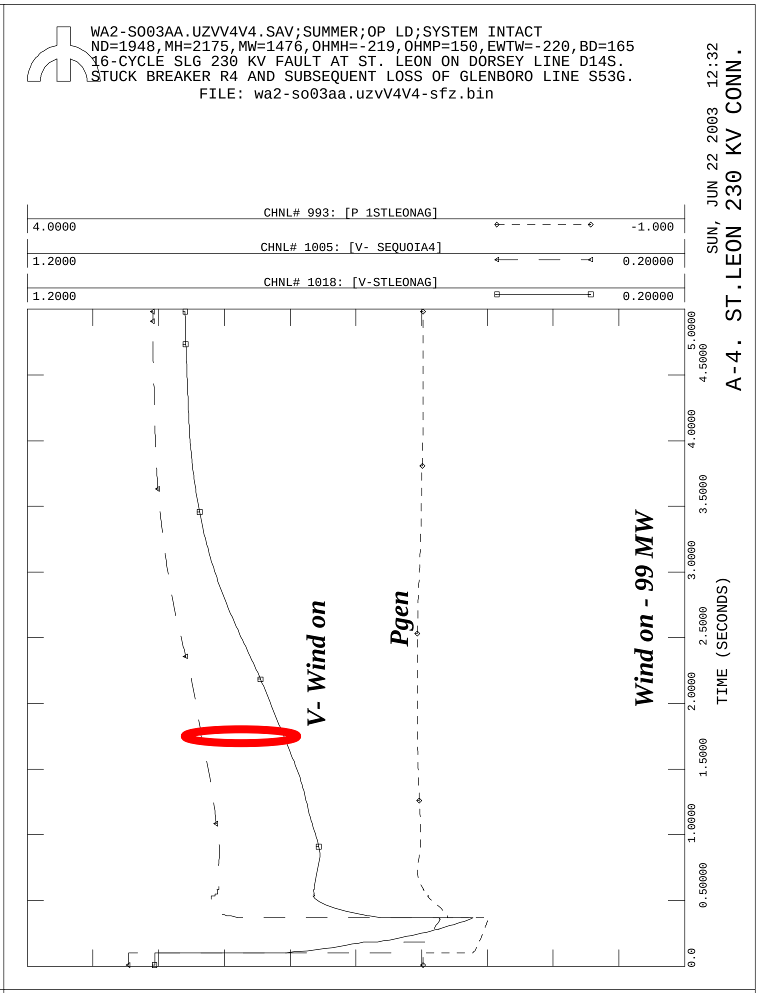
Figure A9 - Case 23 (99 MW wind)
Prior outage of St. Leon 230-66 kV Bank 4
3-phase fault on St. Leon 230-66 kV Bank 3 (se3)

Figure A10 - Case 72 (49.5 MW wind)
Prior outage of St. Leon 230-66 kV Bank 4
3-phase fault on St. Leon 230-66 kV Bank 3 (se3)


WA2-SO03SL.UZVV4V4.SAV;SUMMER;OP LD;STLEON-LET 230KV O/S
ND=1950,MH=2175,MW=1477,OHMH=-220,OHMP=150,EWTW=-220,BD=165
5-CYCLE 3-PHASE 230 KV FAULT AT ST. LEON END OF
ST. LEON - DORSEY LINE D14S
FILE: wa2-so03sl.uzvV4V4-sa3.bin

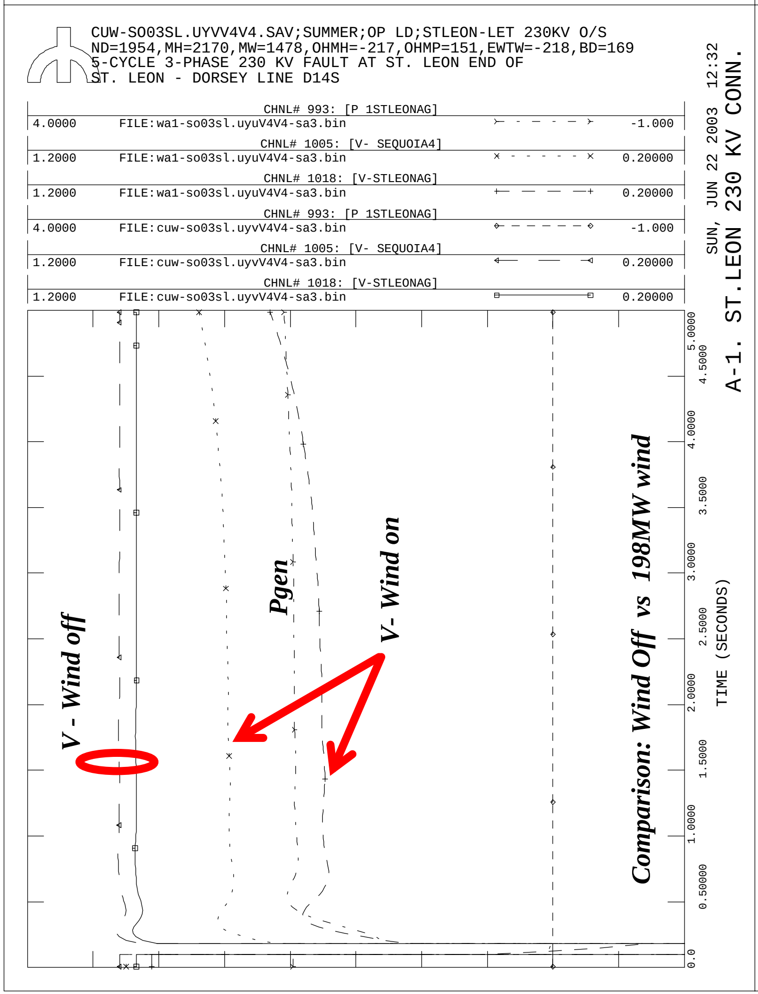
A-2. ST.LEON 230 KV CONN.

SUN, JUN 22 2003 12:32


WA2-SO03AA.UZVV4V4.SAV;SUMMER;OP LD;SYSTEM INTACT
ND=1948,MH=2175,MW=1476,OHMH=-219,OHMP=150,EWTW=-220,BD=165
16-CYCLE SLG 230 KV FAULT AT ST. LEON ON DORSEY LINE D14S.
STUCK BREAKER R4 AND SUBSEQUENT LOSS OF GLENBORO LINE S53G.
FILE: wa2-so03aa.uzvV4V4-sfz.bin

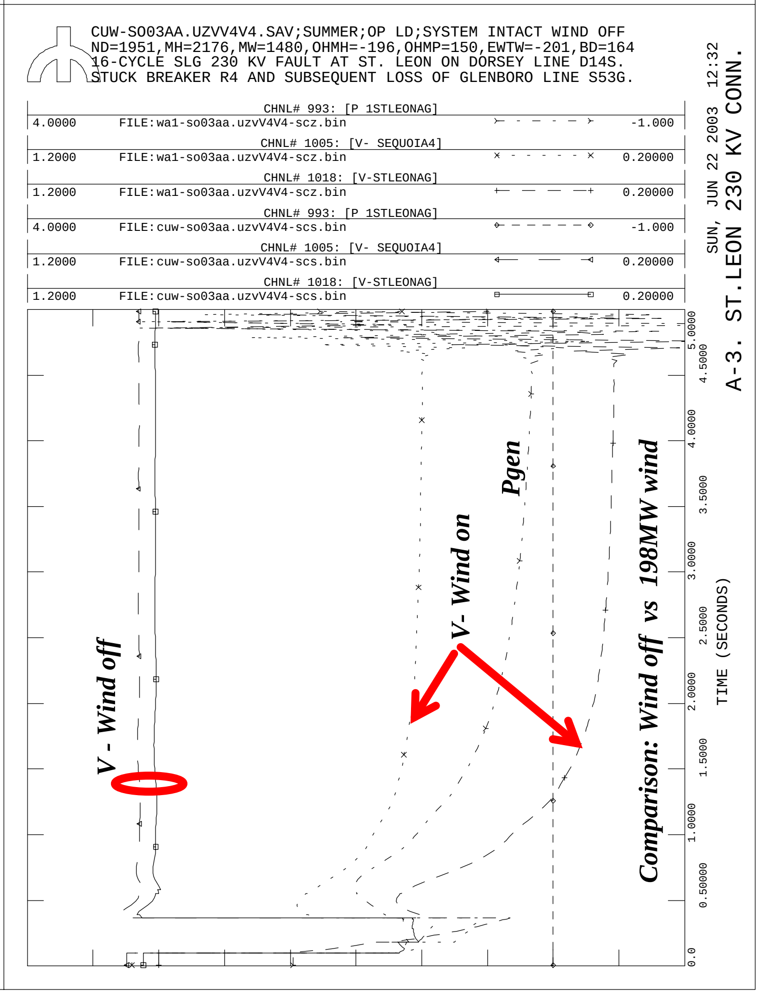
A-4. ST.LEON 230 KV CONN.

SUN, JUN 22 2003 12:32


CUW-SO03SL.UYVV4V4.SAV;SUMMER;OP LD;STLEON-LET 230KV O/S
ND=1954,MH=2170,MW=1478,OHMH=-217,OHMP=151,EWTW=-218,BD=169
5-CYCLE 3-PHASE 230 KV FAULT AT ST. LEON END OF
ST. LEON - DORSEY LINE D14S

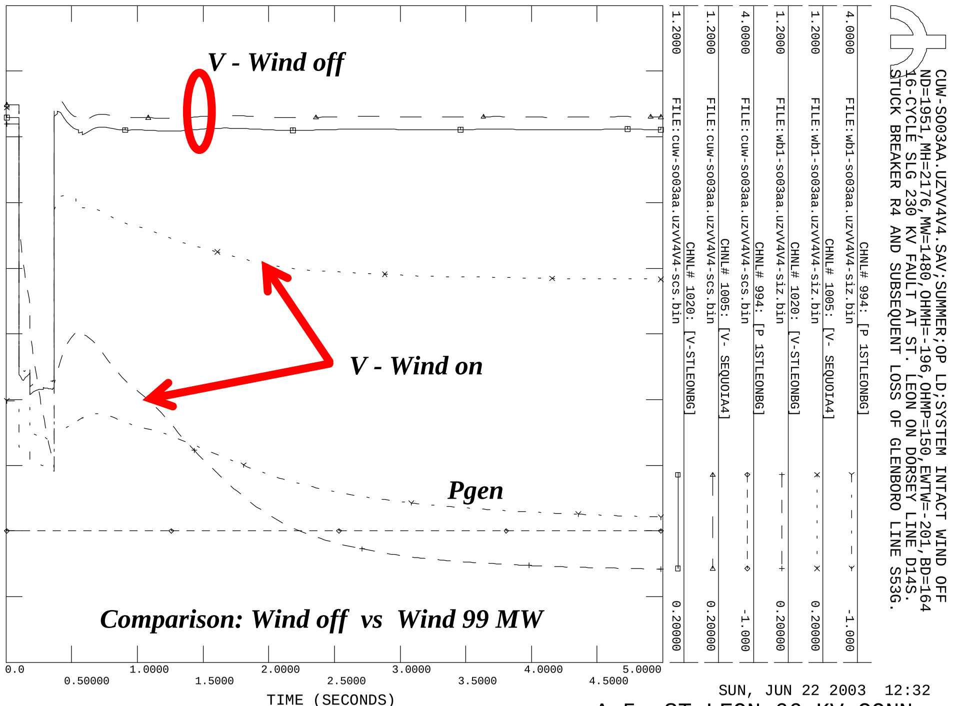
A-1. ST.LEON 230 KV CONN.

SUN, JUN 22 2003 12:32


CUW-SO03AA.UZVV4V4.SAV;SUMMER;OP LD;SYSTEM INTACT WIND OFF
ND=1951,MH=2176,MW=1480,OHMH=-196,OHMP=150,EWTW=-201,BD=164
16-CYCLE SLG 230 KV FAULT AT ST. LEON ON DORSEY LINE D14S.
STUCK BREAKER R4 AND SUBSEQUENT LOSS OF GLENBORO LINE S53G.

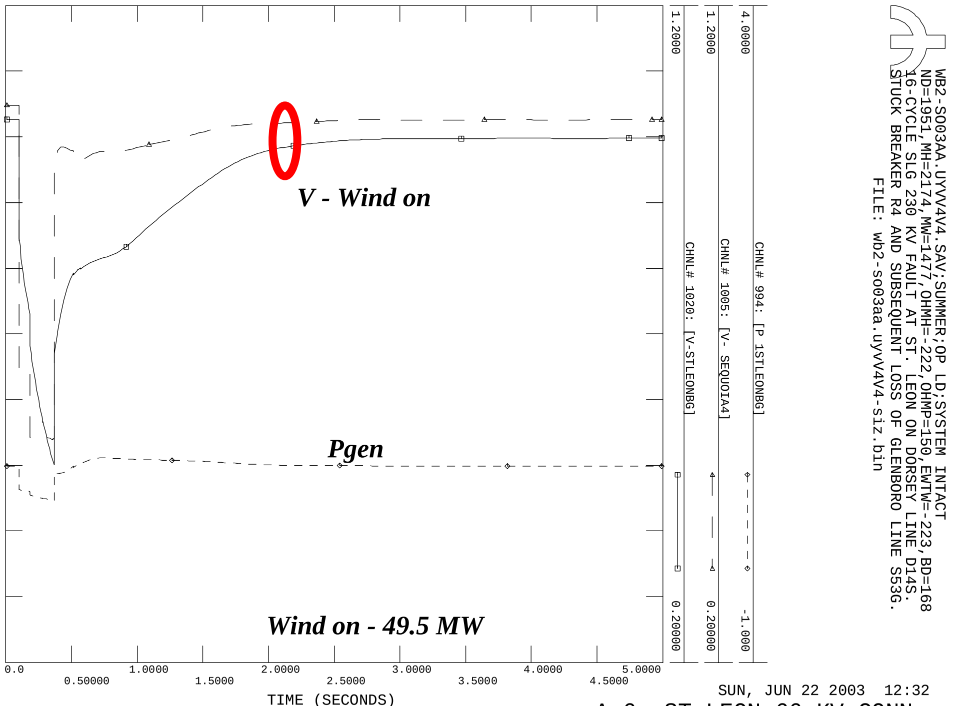
A-3. ST.LEON 230 KV CONN.

SUN, JUN 22 2003 12:32



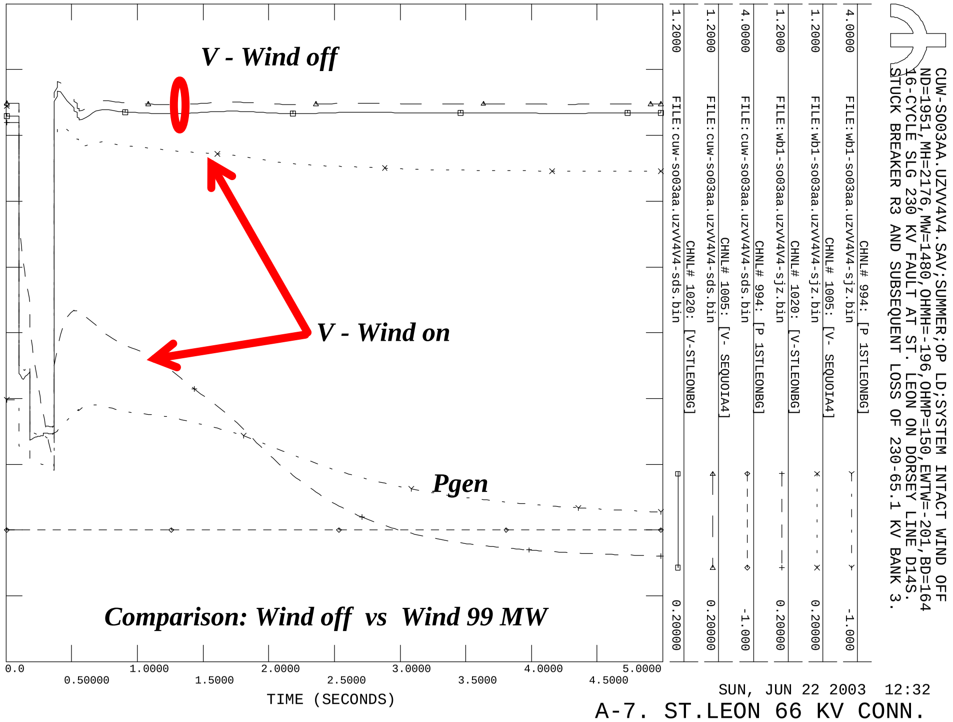
SUN, JUN 22 2003 12:32

A-5. ST.LEON 66 KV CONN.



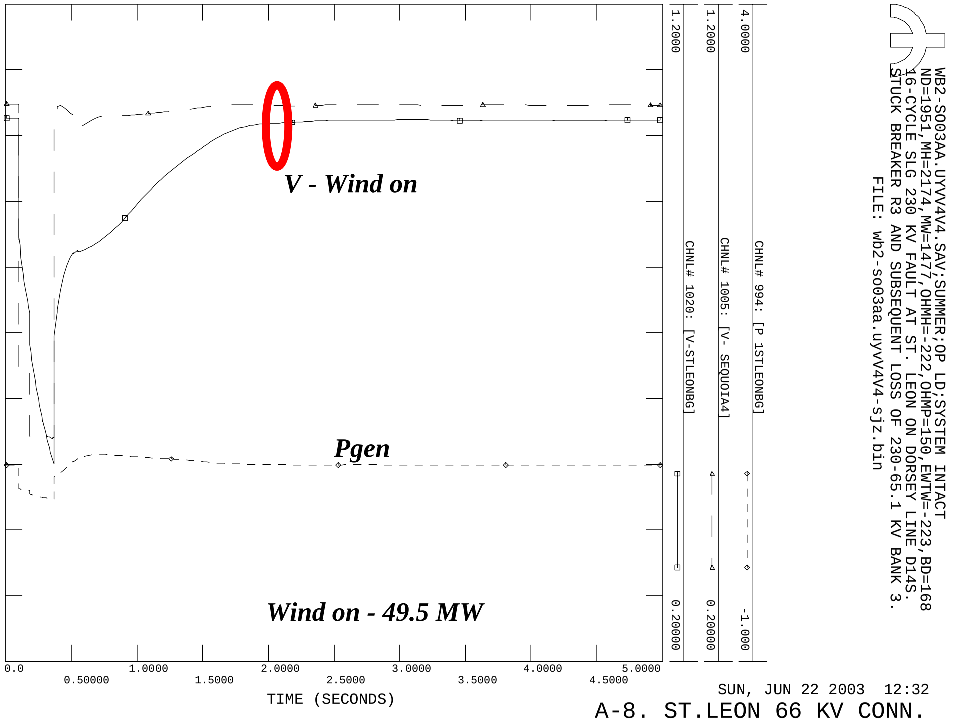
SUN, JUN 22 2003 12:32

A-6. ST.LEON 66 KV CONN.



SUN, JUN 22 2003 12:32

A-7. ST.LEON 66 KV CONN.



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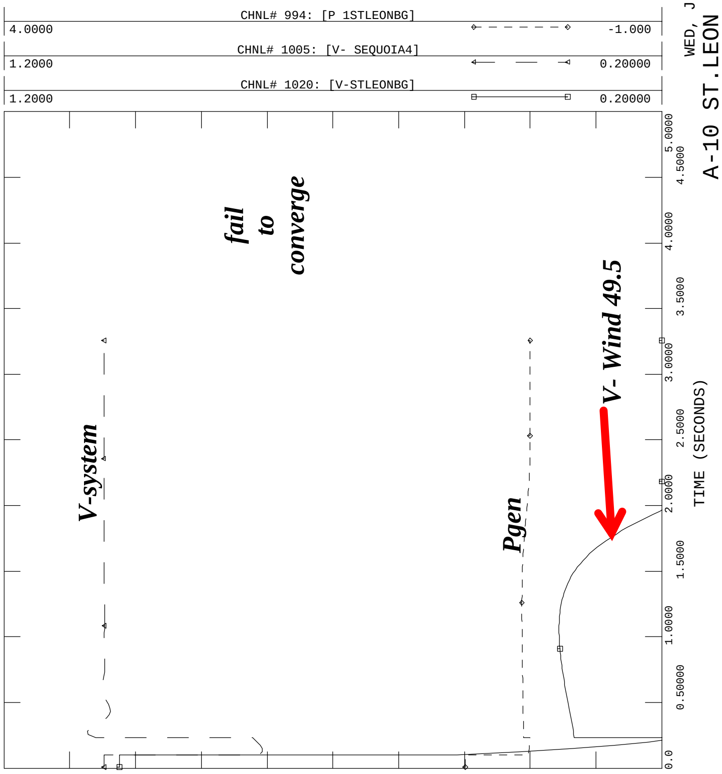
A-8. ST.LEON 66 KV CONN.

WB2-SO03SB.UYVV4V4.SAV;SUMMER;OP LD;STLEON 230-66 BANK 3 O/S
ND=1951,MH=2174,MW=1477,OHMH=-222,OHMP=150,EWTW=-223,BD=168
8-CYCLE 3-PHASE 65.1 KV FAULT ON ST. LEON 230-66
KV BANK 3

FILE: wb2-so03sb.uyvV4V4-se3.bin



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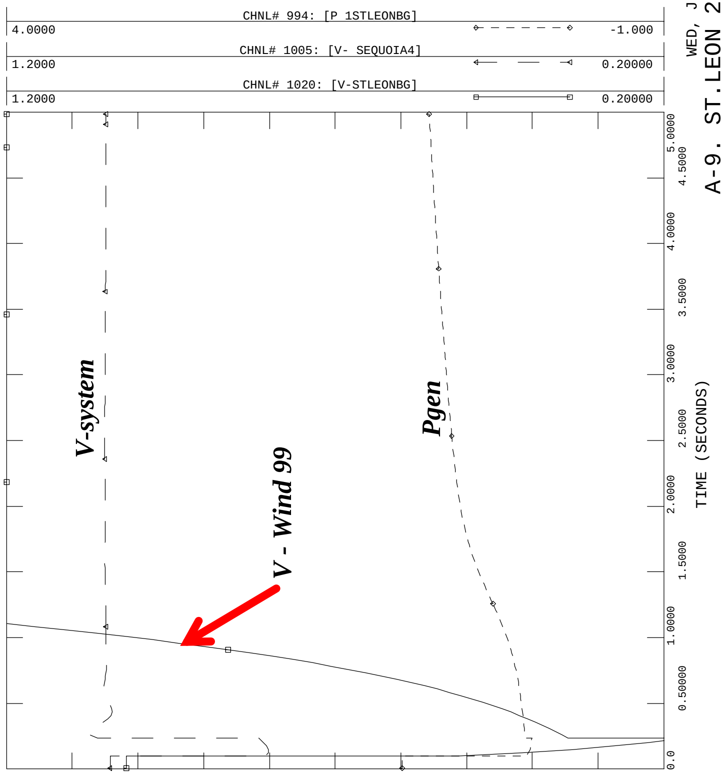
A-10 ST.LEON 66 KV CONN.

WB1-SO03SB.UZVV4V4.SAV;SUMMER;OP LD;STLEON 230-66 BANK 3 O/S
ND=1947,MH=2177,MW=1476,OHMH=-216,OHMP=150,EWTW=-217,BD=164
8-CYCLE 3-PHASE 65.1 KV FAULT ON ST. LEON 230-66
KV BANK 3

FILE: wb1-so03sb.uzvV4V4-se3.bin



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A-9. ST.LEON 230 KV CONN.

Appendix B
P-V Curves

P-V Curves are provided as follows:

B-1 St. Leon 230 kV connection alternative
Trip 230 kV lines D14S (Dorsey-St. Leon) and S53G (St. Leon-Glenboro)

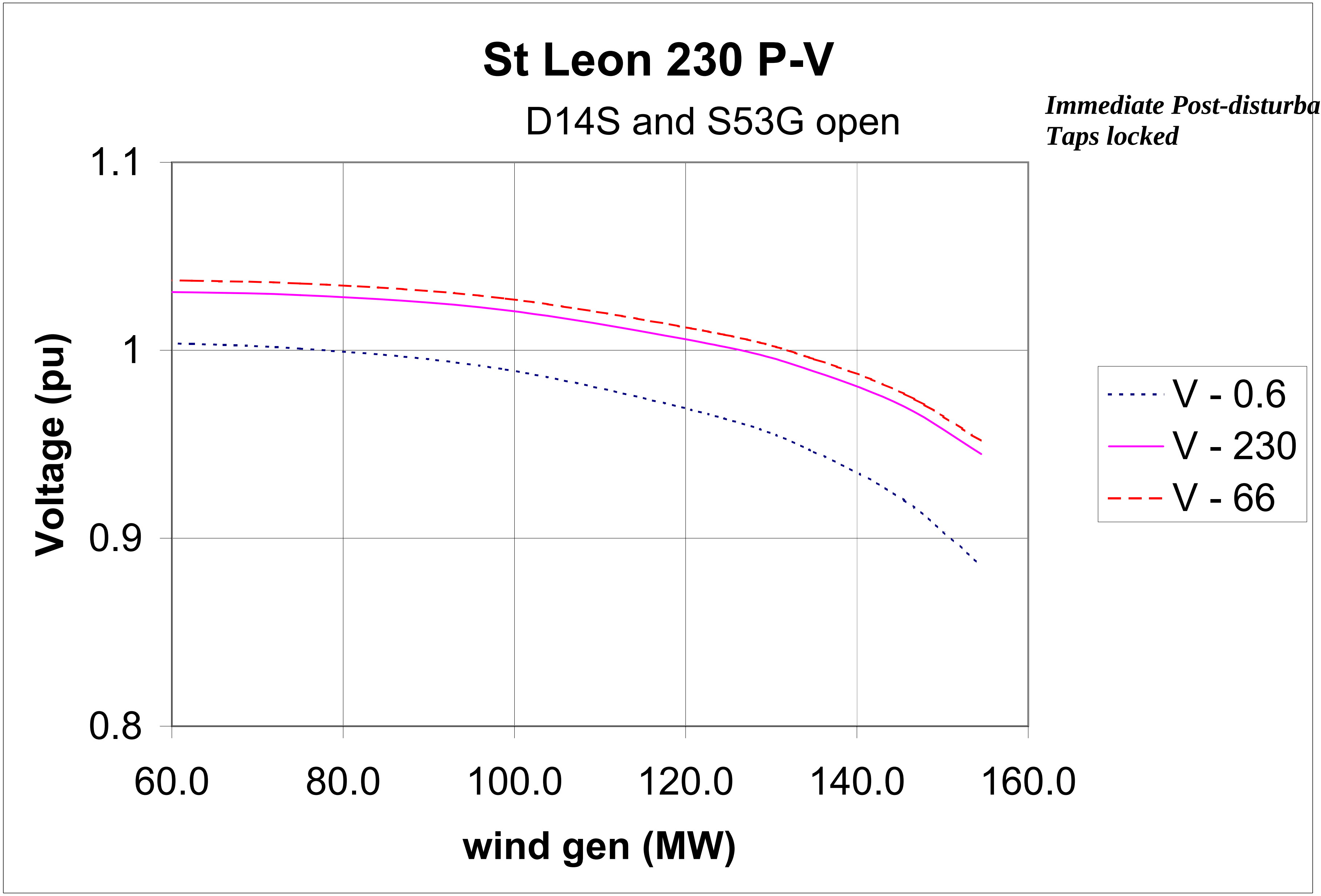
Solved with tap changers and phase shifters enabled
(Post-disturbance)

B-2 St. Leon 66 kV connection alternative
Trip 230 kV lines D14S (Dorsey-St. Leon) and S53G (St. Leon-Glenboro)

Solved with tap changers and phase shifters locked
(Immediate post-disturbance)

B-3 St. Leon 66 kV connection alternative
Trip 230 kV lines D14S (Dorsey-St. Leon) and S53G (St. Leon-Glenboro)

Solved with tap changers and phase shifters locked
(Immediate post-disturbance)



Immediate Post-disturbance
Taps locked

FIGURE B-1

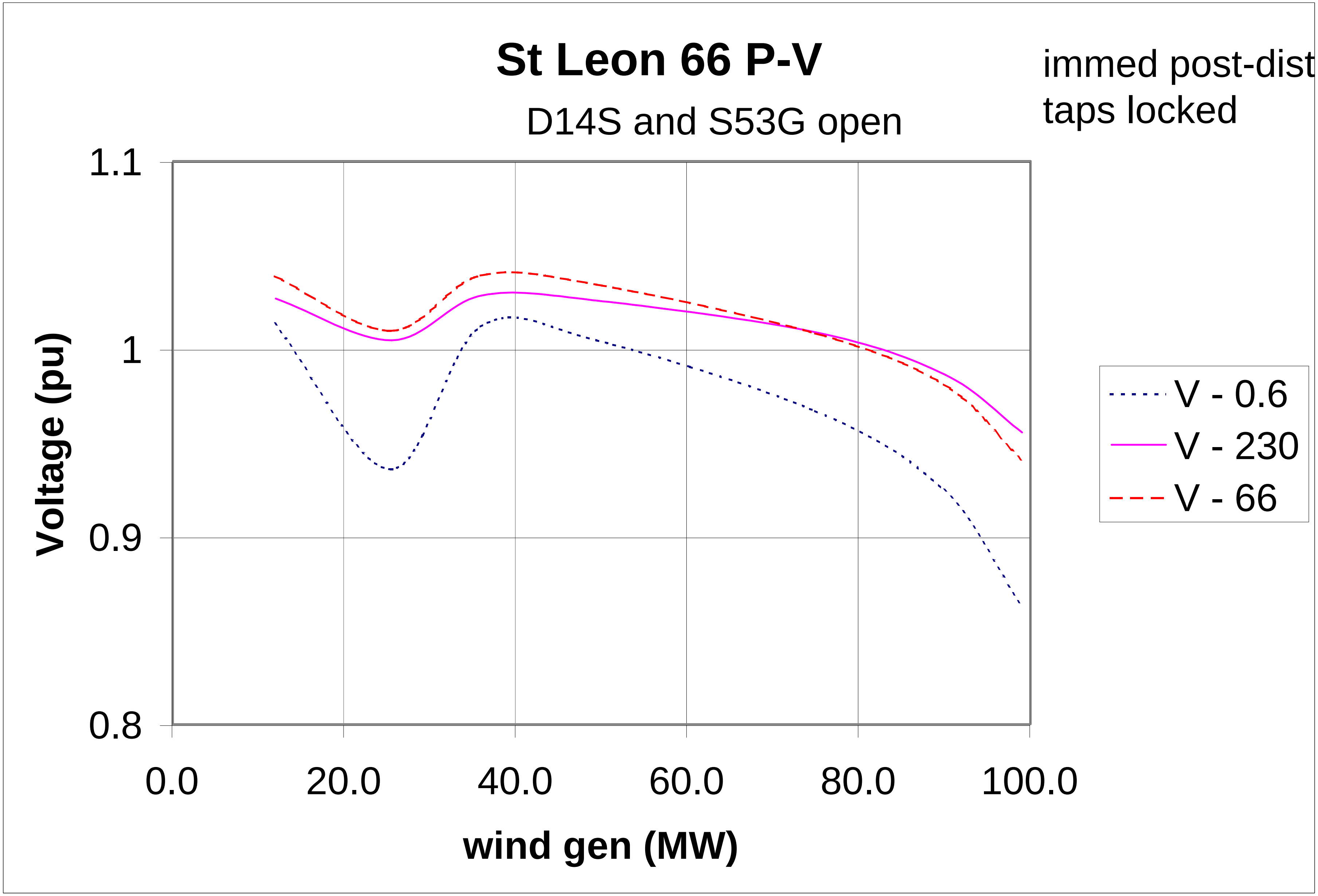

St Leon 66 P-V
D14S and S53G open
immed post-dist
taps locked
Voltage (pu)
1.1
1
0.9
0.8
0.0
20.0
40.0
60.0
80.0
100.0
wind gen (MW)
V - 0.6
V - 230
V - 66

FIGURE B-2

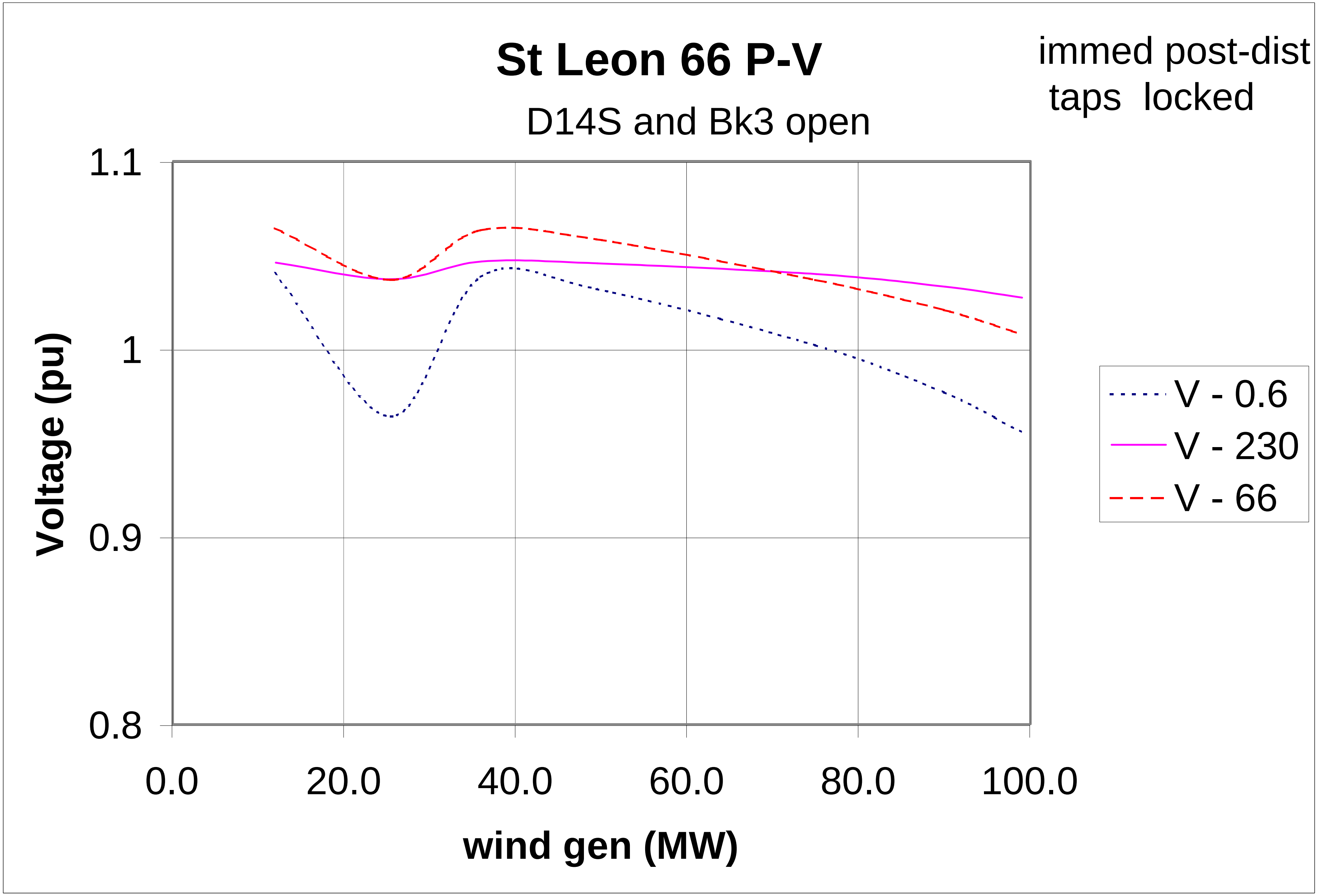

St Leon 66 P-V
D14S and Bk3 open
immed post-dist
taps locked
1.1
1
0.9
0.8
Voltage (pu)
0.0
20.0
40.0
60.0
80.0
100.0
wind gen (MW)
V - 0.6
V - 230
V - 66

FIGURE B-3

Appendix C
Min and Max Transient Voltage

Base Case - no wind

Case				V - St. Leon 230		V - St. Leon 66		
No.	**Case Name**	**Prior Outag**	**Wind**	**min**	**max**	**min**	**max**	**Comment**
1	cuw-so03aa.uzvV4V4-ag1	None	no	1.0259		1.0319		
3	cuw-so03aa.uzvV4V4-ei2	None	no	1.0248		1.0308		
5	cuw-so03aa.uzvV4V4-mqs	None	no	1.0240		1.0299		
7	cuw-so03aa.uzvV4V4-nbz	None	no	1.0332	1.1877	1.0392	1.1948	
9	cuw-so03sl.uyvV4V4-sa3	sl	no	1.0500		1.0495		
11	cuw-so03ds.uyvV4V4-sb3	ds	no		1.0793		1.0855	
13	cuw-so03aa.uzvV4V4-scs	None	no	1.0251		1.0311		
15	cuw-so03aa.uzvV4V4-sds	None	no		1.0818		1.0943	
22	cuw-so03sb.uzvV4V4-se3	sb	no	1.0374		0.0000		66kV bus becomes isolated

Case				V - Elie 230		
No.	**Case Name**	**Prior Outag**	**Wind**	**min**	**max**	**Comment**
30	cuw-so03ce.uzvV4V4-eas	ce	no	0.0000		Bus becomes isolated
32	cuw-so03de.uzvV4V4-ebs	de	no	0.0000		Bus becomes isolated
34	cuw-so03aa.uzvV4V4-ecs	None	no	0.0000		Bus becomes isolated
36	cuw-so03aa.uzvV4V4-eds	None	no	0.0000		Bus becomes isolated
42	cuw-so03lr.uyvV4V4-la3	lr	no	0.0000		Bus becomes isolated
44	cuw-so03lg.uyvV4V4-lb3	lg	no	0.0000		Bus becomes isolated
46	cuw-so03aa.uzvV4V4-lcs	None	no	0.0000		Bus becomes isolated
48	cuw-so03aa.uzvV4V4-lds	None	no	0.0000		Bus becomes isolated

Case				V - Lena 230		
No.	**Case Name**	**Prior Outag**	**Wind**	**min**	**max**	**Comment**
50	viw-wp02aa.ZNZ0Y4W-oas	None	no	0.9252		
52	viw-wp02aa.ZNZ0Y4W-pas	None	no	0.9130		
54	viw-wp02lr.ZNZ0Y4W-la3	lr	no	0.0000		Bus becomes isolated
56	viw-wp02lg.ZNZ0Y4W-lb3	lg	no	0.0000		Bus becomes isolated
58	viw-wp02aa.ZNZ0Y4W-lcs	None	no	0.0000		Bus becomes isolated
60	viw-wp02aa.ZNZ0Y4W-lds	None	no	0.0000		Bus becomes isolated
62	dnw-wo02ma.9Pn0Y1W-ems	ma	no	0.9520		
64	dnw-wo02ma.9Pn0Y1W-lcs	ma	no	0.0000		Bus becomes isolated
66	dnw-wo02ma.9Pn0Y1W-lds	ma	no	0.0000		Bus becomes isolated

🟨 - Voltage violation (MH - post fault < 0.7pu)

Appendix C
Min and Max Transient Voltage

St Leon 230 kV connection - wind on

Case				V - St. Leon 230		V - St. Leon 66		
No.	Case Name	Prior Outag	Wind	min	max	min	max	Comment
2	wa1-so03aa.uzvV4V4-ag1	None	198 MW	1.0174		1.0297		
4	wa1-so03aa.uzvV4V4-ei2	None	198 MW	1.0136		1.0259		
6	wa1-so03aa.uzvV4V4-mqs	None	198 MW	1.0098		1.0221		
8	wa1-so03aa.uzvV4V4-nbz	None	198 MW	1.0306	**1.1580**	1.0430	1.1730	Overvoltage would be higher at lower gen (see 7)
10	wa1-so03sl.uyuV4V4-sa3	sl	198 MW	0.8876		0.8926		slow recovery, 11% voltage decline at 5 seconds
12	wa1-so03ds.uzuV4V4-sb3	ds	198 MW	0.9021		0.9188		
14	wa1-so03aa.uzvV4V4-scz	None	198 MW	**0.6000**		0.6070		dynamic voltage instability
16	wa1-so03aa.uzvV4V4-sdz	None	198 MW	0.9339		0.9505		
68	wa2-so03sl.uzvV4V4-sa3	sl	99 MW	0.9950		0.9940		
69	wa2-so03aa.uzvV4V4-sfz	None	99 MW	0.9085		0.9193		slow voltage recovery

St Leon 66 kV connection - wind on

Case				V - St. Leon 230		V - St. Leon 66		
No.	Case Name	Prior Outag	Wind	min	max	min	max	Comment
17	wb1-so03aa.uzvV4V4-ag1	None	99 MW	1.0215		1.0310		
18	wb1-so03aa.uzvV4V4-ei2	None	99 MW	1.0185		1.0293		
19	wb1-so03aa.uzvV4V4-mqs	None	99 MW	1.0166		1.0232		
20	wb1-so03aa.uzvV4V4-nbz	None	99 MW	1.0314	1.1716	1.0378	**1.1763**	Overvoltage would be higher at lower gen (see 7)
21	wb1-so03sl.uyvV4V4-sa3	sl	99 MW	0.9725		0.9283		
23	wb1-so03sb.uzvV4V4-se3	sb	99 MW	1.0394	1.0746	0.3569	3.4380	Wind generation isolates onto MH 66kV load
24	wb1-so03aa.uzvV4V4-siz	None	99 MW	0.7830		**0.6647**		sustained voltage depression
25	wb1-so03aa.uzvV4V4-sjz	None	99 MW	0.9450		**0.6971**		sustained voltage depression
70	wb2-so03aa.uyvV4V4-siz	None	49.5 MW	0.9643		0.9471		
71	wb2-so03aa.uyvV4V4-sjz	None	49.5 MW	1.0139		0.9693		
72	wb2-so03sb.uyvV4V4-se3	sb	49.5 MW	1.0382		0.0040		Wind generation isolates onto MH 66kV load

🟨 - Voltage violation (MH - post fault < 0.7pu)

Bold NEG Micon - Grid connection 100 ms voltage violation (<0.85 pu or > 1.125 pu)

Appendix C
Min and Max Transient Voltage

Elie 230 kV connection - wind on

Case No.	Case Name	Prior Outag	Wind	V - Elie 230		Comment
				min	max	
26	wc1-so03aa.uzvV4V4-ag1	None	99 MW	1.0250		
27	wc1-so03aa.uzvV4V4-ei2	None	99 MW	1.0269		
28	wc1-so03aa.uzvV4V4-mqs	None	99 MW	1.0192	1.0686	
29	wc1-so03aa.uzvV4V4-nbz	None	99 MW	1.0398	**1.2200**	Overvoltage would be higher at lower gen (case 7)
31	wc1-so03ce.uzvV4V4-eas	ce	99 MW		4.3200	Wind plant becomes isolated
33	wc1-so03de.uyvV4V4-ebs	de	99 MW		4.4800	Wind plant becomes isolated
35	wc1-so03aa.uzvV4V4-ecz	None	99 MW		4.2700	Wind plant becomes isolated
37	wc1-so03aa.uzvV4V4-edz	None	99 MW	0.6840	4.2100	Wind plant becomes isolated

🟨 - Voltage violation (MH - post fault < 0.7pu)

Bold NEG Micon - Grid connection 100 ms voltage violation (<0.85 pu or > 1.125 pu)

Appendix C
Min and Max Transient Voltage

Lena 230 kV connection - wind on

Case No.	Case Name	Prior Outag	Wind	V - Lena 230 min	 max	Comment
MH>US transfer						
38	wd1-so03aa.uzuV4V4-ag1	None	99 MW	1.0048	1.0958	
39	wd1-so03aa.uzuV4V4-ei2	None	99 MW	1.0023		
40	wd1-so03aa.uzuV4V4-mqs	None	99 MW	1.0109		
41	wd1-so03aa.uzuV4V4-nbz	None	99 MW	1.0042	1.1430	Lena 230kV Voltage is > 1.125 for < 100 msec
43	wd1-so03lr.uyvV4V4-la3	lr	99 MW		4.5000	Wind plant becomes isolated
45	wd1-so03lg.uzuV4V4-lb3	lg	99 MW		4.4400	Wind plant becomes isolated
47	wd1-so03aa.uzuV4V4-lcz	None	99 MW		4.2800	Wind plant becomes isolated
49	wd1-so03aa.uzuV4V4-ldz	None	99 MW		4.2800	Wind plant becomes isolated
US>MH transfer						
51	wd1-wp02aa.ZNZ0Y4W-oas	None	99 MW	0.9073		
53	wd1-wp02aa.ZNZ0Y4W-pas	None	99 MW	0.8960		
55	wd1-wp02lr.ZNZ0Y4W-la3	lr	99 MW		3.2100	Wind plant becomes isolated
57	wd1-wp02lg.ZNZ0Y4W-lb3	lg	99 MW		3.0700	Wind plant becomes isolated
59	wd1-wp02aa.ZNZ0Y4W-lcz	None	99 MW	0.0000	3.0500	Wind plant becomes isolated
61	wd1-wp02aa.ZNZ0Y4W-ldz	None	99 MW		3.0100	Wind plant becomes isolated
63	wd1-wo02ma.9Pn0Y1W-ems	ma	99 MW	0.9168		
65	wd1-wo02ma.9Pn0Y1W-lcz	ma	99 MW	0.5040	2.9930	Wind plant becomes isolated
67	wd1-wo02ma.9Pn0Y1W-ldz	ma	99 MW	0.4990	2.9710	Wind plant becomes isolated
73	wd2-wo02ma.9Pn0Y1W-lcz	ma	49.5 MW	0.4970	3.0050	Wind plant becomes isolated
74	wd2-wo02ma.9Pn0Y1W-ldz	ma	49.5 MW	0.5060	2.9800	Wind plant becomes isolated

🟨 - Voltage violation (MH - post fault < 0.7pu)

Bold NEG Micon - Grid connection 100 ms voltage violation (<0.85 pu or > 1.125 pu)