Lena Wind Farm
Interconnection Evaluation Study

Performed by:

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Executive Summary

An Interconnection Evaluation Study (IES) has been performed to determine the transmission facilities necessary to connect a 50 or 99 MW wind farm near Lena, 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 is one option for connecting the wind farm, which is tapping 230 kV tie line G82R (a 170 km line extending from Glenboro, MB to Rubgy, USA) near Lena, which is approximately 77 km from Glenboro along line G82R. This option requires line G82R to be sectionalized at Portage with a three-breaker ring bus. Analysis was performed to determine the amount of wind generation that can be connected at this location. The wind farm distribution station is assumed to be a maximum of 1.6 km away from the proposed G82R tap.

For this location, 99 MW of generation can be accommodated with a single transmission line. 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 beyond the minimum TSIR requirements may be necessary for a wind farm tapping 230 kV line G82R if it is larger than 12 MW based on a maximum 2% voltage change criterion for plant loss. Further investigation would be required in an Interconnection Facilities Study phase.

There are no short circuit concerns for the Lena 230 kV connection location.

Constrained interface analysis showed the greatest impact of the wind connection at Lena increased transfers on the following interfaces: 99 MW wind farm: GRIS_LNC transfer increased by 3.1 MW, 50 MW wind farm: COOPER_S transfer increased by 2.0 MW. A wind farm at Lena would require an additional investigation of NATC.

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), the 110 kV between Mohawk and St. Vital (XV39), the 110 kV line between Rosser and Inkster (RS51), the 110 kV line between Brandon and Victoria (BE3), the 230 kV line between Dorsey and Rosser (D5R), a 230 kV line

between Sheyenne and Fargo (USA), and the 230-63.5 kV Ridgeway transformer banks . A 100 MW wind farm impacts the 110 kV line between Cornwallis and Brandon (CB 42) in addition to the lines listed for a 50 MW farm.

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.

Under winter MH-US import (MH-US) conditions, Lena stuck breaker faults result in the loss of two MH generation sources, the Lena-Rugby tie and the wind plant. This has greatest impact with the prior outage of 500 kV line D602F. At either 99 MW or 49.5 MW wind generation the Lena fault results in cascading loss of the Manitoba-Ontario ties by Kenora power surge protection ($\Delta P/\Delta\theta$). This protection is set to prevent northwest Ontario instability due to a power surge west from their system following the loss of importing MH-US ties. Further study would be required to determine whether it is possible to de-sensitize this protection, while ensuring Ontario stability.

The approximate costs of the transmission facilities necessary to connect the wind farm to line G82R near Lena was calculated for planning purposes. The cost to tap a 50 or 99 wind farm to line G82R near Lena with a three-breaker ring bus is $14.828 million. A more detailed cost estimate would be developed in the Interconnection Facilities Study.

The Generator's proposed in-service date of December 2004 is not achievable. The earliest in-service date is October 31, 2005. This date is preliminary and would be confirmed during the Interconnection Facilities Study.

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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 Lena, Manitoba. The Generator is proposing to develop a 50 MW or 99 MW wind farm. The proposed in-service date is Dec. 2004.

The Generator has indicated that the wind turbines could be installed in Township-Range 1-16W. 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 of 1.6 km away from the proposed G82R tap location.

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.

230 kV line G82R is a 170 km line extending from Glenboro (MB) to Rugby (USA), with a summer rating of 390 MVA. The Lena wind farm would be tapped approximately 77 km from Glenboro. Fig. 1 is a single line diagram showing the existing facilities connected to line G82R.

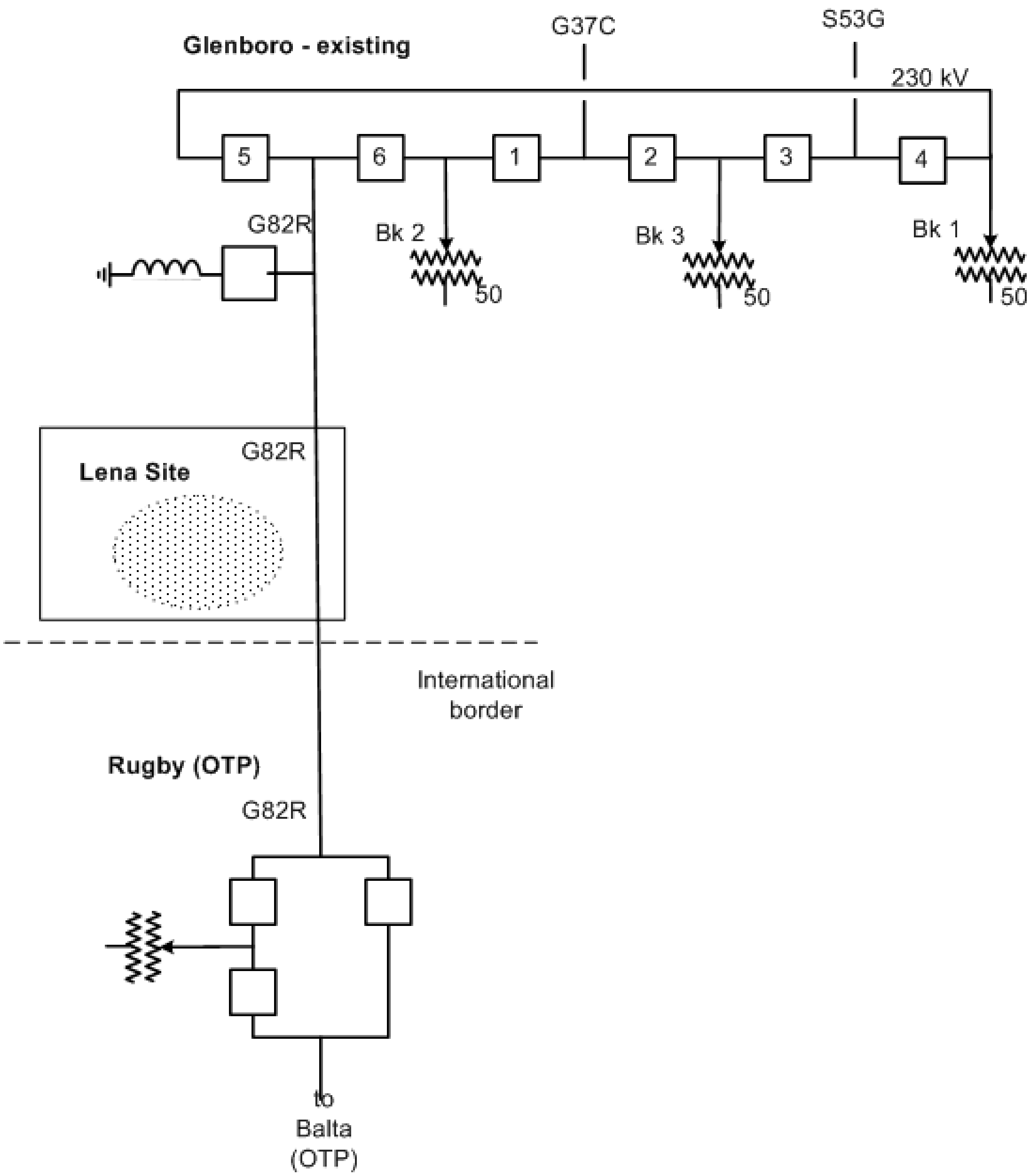

Fig. 1: Existing line G82R single line diagram.

New generation connected to a networked 230 kV transmission line requires as a minimum that a line be sectionalized (2 circuit breakers) for protection and reliability purposes. Line G82R is an interconnection transmission line extending from Manitoba to the USA, and in order to not adversely affect availability and reliability of the tie line it is required to sectionalize the line with a three-breaker ring bus. There are high costs associated with limiting MH-US transfers.

Fig. 2 shows the major Interconnection Facilities required to tap the wind farm into 230 kV line G82R. Three 230 kV circuit breakers (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 Generator Facilities. 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.

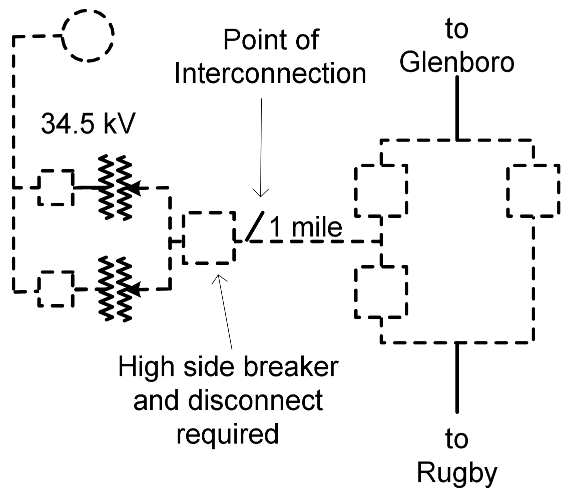

Fig. 2: Connection of wind farm to line G82R.

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.

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.

1.3 Generator Connection Requirements

Please refer to the Manitoba Hydro Transmission System Interconnection Requirements (TSIR) document for complete details. The document can be found on-line at http://oasis.midwestiso.org/documents/Mheb/queue.html .

2.0 Wind Turbine Models

2.1 Introduction

Please refer to the St. Leon IES report [1].

2.2 Reactive Power Compensation

The Manitoba Hydro Transmission System Interconnection Requirements (TSIR) state that any Generator Facility greater than 10 MW that is comprised of induction type generators (such as may be connected to wind turbines) shall design the Generator Facilities, at minimum, to maintain power delivery at continuous rated power output measured at the generator intermediate bus at a power factor within the range of 0.95 overexcited (leading) to 0.95 underexcited (lagging). The reactive supply must be available over the full range of operating conditions. The use of mechanically-switched reactors or capacitors, static var compensators or similar devices may be acceptable alternatives for providing all or part of the reactive supply. In addition, Generator must be capable of regulating the voltage at the point of interconnection. At minimum, if the Generator Facility is relying on mechanically switched capacitors for steady state voltage regulation, the capacitors must be available for re-insertion within 5 seconds, and the voltage response time of the capacitors shall be adjustable and not greater than 15 seconds. Please refer to the TSIR for further details. The Interconnection Facilities Study phase would address these details.

For details on the wind turbine reactive power compensation please refer to the St. Leon IES report [1].

2.3 Wind Turbine Control Types

Please refer to the St. Leon IES report [1].

2.4 Wind Turbine PSS/E Model Discussion

Please refer to the St. Leon IES report [1].

3.0 Steady-State AC Power Flow Analysis (ACCC)

3.1 Introduction

Please refer to St. Leon IES report [1].

The difference between the Lena wind site and the St.Leon wind site is that Lena is located on tie line G82R. Because of this, contingency and monitoring files for the entire North MAPP area were used for the Lena ACCC analysis. When screening the ACCC results that had applied the North MAPP area contingency file, there were approximately 50 to 100+ “not converged” contingency cases per loadflow (there are 44 different loadflow cases in total). In many cases the non-convergence occurred due to a hunting shunt capacitor. This shunt capacitor(s) would often be different for each contingency. Due to time constraints it was not possible to manually solve each not-converged case for each loadflow. Instead, the ACCC analysis was re-run with all switched shunts locked. Many previously not converged cases solved using this method, however this presented many more pre-existing voltage violations that were most likely invalid.

ACCC results for transmission lines and transformer overloads in the North MAPP area are not included. There were many pre-existing contingency overloads and voltage violations. Two obstacles in analyzing the North MAPP area are that the contingency file tripped all single branches which may have applied some invalid contingencies, and where there are pre-existing overloads it is unknown whether there are protection schemes that would operate to alleviate the overloads or voltage violations. The screening files that compared the wind cases to the no wind cases showed essentially no impact on the overloads. The one case will be that showed impacts will be mentioned in the following Section 3.4. Due to time constraints it was not possible to screen through all of the pre-existing voltage violations, however the screening files that compared the wind cases to the no wind cases showed no impact on the voltage violations.

The pre-existing North MAPP area overloads and voltage violations could be studied at a later time but are not discussed in this memo unless they were shown to be impacted by the wind generation.

3.2 Study Criteria

Please refer to St. Leon IES report [1].

3.3 Power Flow Model

Please refer to St. Leon IES report [1].

3.4 ACCC Results

Wind generation up to 99 MW at the Lena 230-kV site causes no new overload concerns. It did however impact several pre-existing (no wind) overloads as listed in Table 1.

Table 1: Lena 230 kV single contingency overload increase

Facility	PTDF (%)	LF Case #	Contingency	Year
McPhillips Bank 8 and Bank 9	3.6	34	HS5/XS49	2008
	3.1	38	HS5/XS49	2008
Raven Lake Bank 3 overcurrent relay	4.4	14	C28R	2004
	4.5	36	C28R	2008
Sheyenne-Fargo 230 kV line[1]	3.1	35	Jamestown-Center 345 kV line	2008
Osprey-Big Fall 115-69 kV transformer	2.0	2	Sheldnp7-Holdcomb7 (PSS/E 30296-60306, cct 1)	2004
	1.9	4		2004
	2.2	12		2004

3.5 Discussion of Limiting Elements

3.5.1 McPhillips Banks 8 and 9

Winnipeg Hydro load is served by power from Pointe du Bois, Slave Falls and from Manitoba Hydro via four phase shifting transformers, one 110 kV Harrow-Scotland (HS5) line and two 63.5 kV transmission lines (TA11/BA10). An outage of any one of the phase shifting transformers results in an overload to the McPhillips healthy phase shifting transformer (Bank 8 or 9) because of the high reactive power flow through it. The overload can be eliminated by manually adjusting the tap changer to reduce the reactive power flow.

3.5.2 Raven Lake Bank 3 Overcurrent Relay Setting

An overcurrent relay is set to trip Raven Lake bank 3 in order to protect underlying 110 kV line MR11. Raven Lake 230-110 kV transformer bank 3 will trip following the loss of Cornwallis - Reston 230 kV line C28R. This contingency already trips the bank before the addition of wind generation, however wind increases the MVA loading through the transformer by 4.5% as shown in Table 2, which correpsonds to the bank tripping sooner with wind as compared to without wind. PSS/E Rate C for the transformer corresponds to the overcurrent relay setting. The transformer has a thermal rating of 110 MVA while the relay is set to trip the bank at 66.5 MVA, therefore there are no real transformer overload issues in this scenario. New overcurrent line protection is planned to be installed at the Raven Lake and Brandon ends of line MR11.

[1] At 700 MW firm import level (as opposed to 900 MW non-firm import), this line is loaded to 100.9% with wind and 100% without wind, only a 1% increase which is below the 2% ACCC screening criteria.

3.5.3 Sheyenne – Fargo 230 kV line

A contingency overload of 104.4% occurs on the 230 kV line from Sheyenne to Fargo following the loss of 345 kV line from Jamestown to Center. The overload is a pre-existing condition that is increased when wind is added. Case 35 models the non-firm MH import level of 900 MW. MH import was adjusted to 700 MW firm import level and ACCC was re-run for this contingency. The overload was reduced to 100.9% with 99 MW wind at Lena and was not overloaded for the no wind case at the 700 MW import level.

3.5.4 OSPREY 7 – BIGFALL8 115-69 kV transformer

A contingency overload of 115-69 kV transformer, PSS/E branch 60297-60662 circuit 1, occurs following the loss of 115 kV line from SHELDNP7 - HOLCOMB7, PSS/E branch 60296-60306 circuit 1. The overload is a pre-existing condition that is increased when wind is added.

3.6 Conclusions

For the single and multiple contingencies investigated, no new violations of post disturbance voltage criteria or thermal loading criteria was caused by the addition of wind generation at Lena into line G82R (99 MW max). The wind farm was shown to impact existing overloads on two facilities in the USA that would require further investigation – a 230 kV line from Sheyenne to Fargo and a 115-69 kV transformer. The additional power from the wind farm was scheduled to Dorsey.

4.0 Steady-State DC Power Flow Analysis (TLTG)

4.1 Introduction

Please refer to St. Leon IES report [1].

4.2 Study Procedure

Please refer to St. Leon IES report [1].

4.3 TLTG Results

4.3.1 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 are shown in Table 2. Case 35, which models the non-firm import level of 900 MW, resulted in an overload of North MAPP area 230 kV line from Sheyenne to Fargo. MH import was adjusted to 700 MW firm import level and TLTG was re-run for this case. The internal MH system overloads were not greatly affected, however the Sheyenne-Fargo line only became overloaded at 151.9 MW of wind generation, which is within the 99 MW target level.

Table 2: Single Contingency Overloads – non-AGC sinks.

Year	Case	Sink	Incremental MW	Limiting Facility	Single Contingency
2008	35	MH load	Pre-existing 29.5[2] 29.7	Ridgeway Bank 2 Sheyenne-Fargo 230 Line YV5	Ridgeway Bank 1 Jamestown-Center 345 Line YX48
2008	37	MH load	63.9	Line CB42	Cornwallis Bk3

Several common tower overloads also occurred. The most limiting cases for 2004 and 2008 are summarized in Table 3.

2 At 700 MW firm import level (as opposed to 900 MW non-firm import), this line becomes overloaded at 151.9 MW of Lena wind generation.

Table 3: Common Tower Contingency Overloads – non-AGC sinks.

Year	Case	Sink	Incremental MW	Limiting Facility	Common Tower Contingency
2004	11	MH load	Pre-existing	MHEX_S	Lines YV5+XV39
2004	13	MH load	Pre-existing Pre-existing Pre-existing	Line YV5 Line BE3 Line XV39 St.V-Dak	Lines YX47+YX48 Lines BE1+BE2 Lines YX47+YX48
2004	19	MH load	47.8	Line D5R	Lines D13R+D16R
2008	35	MH load	Pre-existing Pre-existing Pre-existing Pre-existing Pre-existing	Line XV39 Line BE3 Line RS51 Line YV5 Line D5R	Lines YX47+YX48 Lines BE1+BE2 Lines YX47+YX48 Lines YX47+YX48 Lines YX47+YX48
2008	33	MH load	Pre-existing	MHEX_S	Lines YV5+XV39

4.3.2 Power scheduled to AGC plants

No limiting overloads occurred for the 2004 cases. For the 2008 cases, one single contingency overload occurred for generation levels below 99 MW. The most limiting cases are summarized in Table 4. Case 35, which models the non-firm import level of 900 MW, resulted in an overload of North MAPP area 230 kV line from Sheyenne – Fargo. MH import was adjusted to 700 MW firm import level and TLTG was re-run for this case. The internal MH system overloads were not greatly affected, however the Sheyenne-Fargo line only became overloaded at 143.5 MW of wind generation, which is within the 99 MW target level.

Table 4: Com. Tower Contingency Overloads – AGC sinks.

Year	Case	Sink	Incremental MW	Limiting Facility	Common Tower Contingency
2008	35	Dors DC	27.9[3]	Sheyenne-Fargo	Jamestown-Center
2008	37	Grd Rap	99.6	Line CB42	Cornwallis Bk 3

Several common tower overloads occurred. The most limiting cases for 2004 and 2008 are summarized in Table 5.

Table 5: Com. Tower Contingency Overloads – AGC sinks.

Year	Case	Sink	Incremental MW	Limiting Facility	Common Tower Contingency
2004	17	Grd Rap	Pre-existing	Line BE3	Lines BE1+BE2
2004	19	Grd Rap	58.7	Line D5R[2]	Lines D13R+D16R
2008	39	Grd Rap	Pre-existing	Line BE3	Lines BE1+BE2

[3] At 700 MW firm import level (as opposed to 900 MW non-firm import), this line becomes overloaded at 143.5 MW of Lena wind generation.

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

Common tower contingency overloads can occur on 110 kV line RS51 following the loss of 110 kV lines YX48 and YX47. 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. The Rosser – Inkster portion of the line has a rating of 186.7 MVA and is sagged to 100 deg C. The line could be re-conductored to mitigate this overload.

4.4.4 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 30 minute overload rating will be applied until the overload situation can be permanently fixed.

4.4.5 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.

4.4.6 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.

4.4.7 MHEX South Flow

MHEX south flow exceeded the maximum stability limit of 2175 MW (reaching up to 2278 MW, 103 MW above the limit) following the common tower loss of 110 kV lines XV39 and YV5. The loss of these lines results in the loss of loads at Wilkes and Dakota. Even with the increased MHEX flows, no tie lines were overloaded. The most heavily loaded line was L20D at 94%. Area generation control (AGC) will operate to control the flow error on the tie lines. If AGC is set to the DC bipoles the error can be corrected at a rate of 150 MW/min, and if AGC is set to Grand Rapids the error can be corrected at a rate of 130 MW/min, assuming there are enough units already on-line to either ramp up/down the power. The case causing the 2175 MW limit to be exceeded is a maximum generation case and therefore there would be enough units on-line to achieve these AGC ramp rates, and the error should be correctable within less than a minute.

4.4.8 Brandon-Victoria 110 kV line BE3

110 kV lines BE1, BE2 and BE3 are parallel lines connecting Brandon G.S. to Brandon Victoria. A common tower loss of lines BE1 and BE2 results in an overload of line BE3. The limiting element is the transmission line itself. It has a thermal rating of 75 deg C, and it could therefore be re-sagged to 100 deg C to provide additional thermal capability up to 108.6 MVA. This corresponds to an increase of 33.7%.

4.5 Conclusions

Table 6 summarizes all of the limiting elements for the Lena wind site that require further investigation depending on the selected amount of wind to be connected.

Table 6: Summary of Limiting Elements.

Contingency	Limiting Elements
Overloaded elements due to wind at Lena 230	
Single	Ridgeway Bank (>0 MW) Line YV5 (>29 MW) Sheyenne-Fargo 230 line (> 29MW) Line CB42 (>63 MW)
Common Tower	Line YV5 (>0 MW) Line BE3 (>0 MW) Line XV39 (>0 MW) Line RS51 (>0 MW) Line D5R (> 0 MW)

5.0 Constrained Interface Analysis

5.1 Introduction

Please refer to St. Leon IES report [1].

5.2 Study Procedure

Please refer to St. Leon IES report [1].

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.

The highest positive distribution factor for the 99 MW generation addition is 3.1% (3.1 MW) and occurs for the GRIS_LNC interface during the 2004 summer off-peak case. Since the impact is slightly greater than 3% and 1 MW, an additional investigation of NATC would be needed.

The impact of adding 50 MW of wind generation at Lena was also studied, and was found to be higher than the 99 MW connection (in terms of percentages, however the actual MW impact decreased but was still greater than the 1 MW criteria). The highest positive distribution factor for the 50 MW generation addition is 3.9% (1.95 MW) and occurs for the COOPER_S interface during the 2004 winter peak case. Since the impact is greater than 3% and 1 MW, an additional investigation of NATC would be needed.

5.4 Conclusions

The greatest impact of the wind connection at Lena increased transfers on the following interfaces:

- 99 MW: GRIS_LNC – increased transfer by 3.1 MW
- 50 MW: COOPER_S – increased transfer by 2.0 MW

A wind farm at Lena would require an additional investigation of NATC.

6.0 Short Circuit Analysis

6.1 Introduction

Please refer to St. Leon IES report [1].

6.2 Fault Study Model

Please refer to St. Leon IES report [1].

6.3 Criteria Used In the Evaluation

Please refer to St. Leon IES report [1].

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.

An addition of 99 MW of wind generation at the Lena 230 kV site results in a S-L-G fault level increase of 5.35 % at Glenboro station, which is only at 16.36 % of the breaker interrupting rating.

6.5 Conclusions

The addition of a 99 MW wind farm at Lena as 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

Please refer to St. Leon IES report [1].

7.2 Study Criteria

Please refer to St. Leon IES report [1].

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 the 230 kV line G82R tap with 99 MW output, as shown in Table 7. Offsetting generation changes were made via the MH DC system. Lower generation levels, down to 49.5 MW, were studied only when transient performance was unacceptable at the 99 MW generation level.

Table 7: 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
wd1-so03aa.uzvV4V4	Lena 230 kV	99	2176	1950	164
viw-wp02aa.ZNZ0Y4W	off	0	-700	-53	-163
wd1-wp02aa.ZNZ0Y4W	Lena 230 kV	99	-700	-52	-163
dnw-wo02ma.9Pn0Y1W	off	0	-500	415	-164
wd1-wo02ma.9Pn0Y1W	Lena 230 kV	99	-500	417	-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 110 and 55 MVA for the 99 and 49.5 MW alternatives, respectively. This is the net rating for 66 or 33 generators, respectively.

With the Lena connection it was assumed that a DC reduction scheme would be applied for each of the Glenboro-Lena and Lena-Rugby line sections, as is currently applied on 230 kV line G82R. The PSS/E snapshot was modified accordingly.

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.
oas	15-cycle SLG 500 kV fault at Dorsey on Dorsey line D602F. Stuck breaker and subsequent loss of Dorsey 500-230 kV Bank 51.
pas	17-cycle SLG 500 kV fault at Forbes on Dorsey line D602F. Stuck breaker and subsequent loss of Forbes 500-230 kV banks.

In addition, the following two classes of local disturbances were simulated to assess performance:

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:

la3	5-cycle 3-phase 230 kV fault at Lena end of Lena - Glenboro line (was G82R)
lb3	5-cycle 3-phase 230 kV fault at Lena end of Lena - Rugby line (was G82R)

lcs or lcz 16-cycle SLG 230 kV fault at Lena on Glenboro line. Stuck breaker and subsequent loss of 230 kV Rugby line.

lds or ldz 16-cycle SLG 230 kV fault at Lena on Rugby line. Stuck breaker and subsequent loss of 230 kV Lena - Glenboro line.

Note: The only difference between cases like lds/ldz, above, is the fault level to represent the SLG fault. The fault level is higher with the wind generation in-service.

7.4 Discussion - Stability Results

Addition of generation in southwest Manitoba at the proposed wind site 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.

Transient voltage response is tabled in Appendix A. 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 Lena 230 kV connection

Because this site connects into a MH-US tie, the scope included additional cases. MH-US north flow conditions were added.

7.4.1.1 MH-US South Flow

It was assumed that MH DC reduction would be provided for the loss of any Glenboro-Lena-Rugby line section. It was assumed to operate for the initial line section loss if the pre-disturbance Lena-Rugby line section was carrying at least 30 MW export to the US. DC reduction therefore operated for the Lena stuck-breaker export cases.

Adding 99 MW of generation at the Lena site transfers export power primarily from D602F to G82R. This generally results in improved transient performance for the MAPP area disturbances at studied high NDEX conditions where D602F loading was high.

There is also modest improvement to MH-US tieline performance for local Lena 3-phase and SLG faults with the addition of wind generation.

Minimum transient relay margins increase by 4% on line B10T with the worst disturbance studied (Sherco SLG stuck breaker fault mqs, cases 5 and 40).

7.4.1.2 MH-US North Flow

With system intact, the 99 MW wind addition reduces 230 kV line G82R north flow by 35 MW, most of which transfers to 500 kV line D602F.

The most extreme disturbance impacting the MH-US ties is the loss of D602F via a Forbes SLG fault with breaker failure. As shown in cases 52 and 53, line G82R minimum transient relay margin increases from 47% to 66% with the wind generation addition. However, 230 kV line B10T relay margin degrades from 165% to 147%.

While the wind case degrades D602F and B10T transient relay margins with the Lena 3-phase fault cases (54-57), margins remain high.

Stuck breaker faults at Lena result in both loss of the Glenboro-Lena-Rugby tieline and 99 MW of Manitoba generation when wind generation is on. Wind addition results in a significant reduction in D602F transient relay margin (722% to 263%) with Lena stuck breaker disturbance ldz (case 61).

7.4.1.3 D602F Prior Outage

With the prior outage of 500 kV line D602F, the 99 MW wind addition reduces 230 kV line G82R north flow by 25 MW, most of which transfers to 230 kV line L20D. This improves G82R transient performance for loss of L20D (ems fault cases 62 and 63), increasing minimum transient relay margin from 40 to 45%.

For local Lena stuck breaker faults, the addition of wind generation results in cascading loss of the Manitoba-Ontario ties (cases 65 & 67). They trip via Kenora $+\Delta P/-\Delta\theta$, set at +50MW and -5°. The 99 MW wind addition increased maximum Kenora - Whiteshell power surge by approximately 9% or 4.0 to 4.8 MW. Line B10T transient relay margins also degrade 50% to approximately 180%.

Additional cases (73 & 74) demonstrated that the Manitoba-Ontario ties similarly trip via Kenora $+\Delta P/-\Delta\theta$ for local stuck breaker faults with only 49.5 MW wind generation.

7.5 Conclusions

Lena 230 kV installation splits existing MH-US tie line G82R into two lines (Glenboro-Lena and Lena-Rugby). Adding generation in this configuration caused concern for potential impact on transfer capability. Therefore MH-US north and south transfer conditions were studied.

Under summer simultaneous export (MH-US and North Dakota) conditions the 99 MW Lena wind addition generally has little impact on Canada-US tie line out-of-step transient performance. Minimum transient relay margins improve by 4% on line B10T with the worst disturbance studied (Sherco stuck breaker fault).

However, under winter MH-US import (MH-US) conditions, Lena stuck breaker faults result in the loss of two MH generation sources, the Lena-Rugby tie and the wind plant. This has greatest impact with the prior outage of 500 kV line D602F. At either 99 MW or 49.5 MW wind generation the Lena fault marginally results in cascading loss of the Manitoba-Ontario ties by Kenora power surge protection ($\Delta P/\Delta\theta$). This protection is set to prevent northwest Ontario instability due to a power surge west from their system following the loss of importing MH-US ties. Further study would be required to determine whether it is possible to de-sensitize this protection, while ensuring Ontario stability.

8.0 Voltage Quality Analysis

8.1 Introduction

Please refer to St. Leon IES report [1].

8.2 Study Criteria

Please refer to St. Leon IES report [1].

8.3 Procedure for Assessment of Voltage Quality

Please refer to St. Leon IES report [1].

8.4 Wind Turbine Voltage Quality Data

Please refer to St. Leon IES report [1].

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 farm is calculated below and summarized in Tables 8 and 9. A strong system refers to normal operation conditions and weak means that there is a prior outage of a single transmission line or transformer.

Table 8: Fault Levels at Lena 230 kV.

System	Strong	Weak
Short Circuit MVA	1348.2	607.8
X/R (degrees)	82.13	81.62

Table 9: Calculation of P_{st} and P_{lt} for 66 Wind Generator Turbines at Lena 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	0.0341	0.0173	0.0279	0.0146	0.0236	0.0742	0.0705
Weak	0.0757	0.0383	0.0618	0.0324	0.0523	0.1645	0.1563

8.5.1 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 and are given in Table 10.

The P_{lt} criterion of 0.6 is violated at Lena 230 kV during the worst case prior outage condition.

Table 10: Calculation of Worst Case P_{st} and P_{lt}.

Location	Lena, 230 kV, 99 MW
System	
Strong	0.2772
Weak	0.6138

8.6 Voltage Fluctuation Due to Loss of Plant

The worst case estimate of voltage fluctuation (dV) 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 11: Calculation of Worst Case Voltage Fluctuation (? V).

Location	kV	MW	MVA_{SC}	dV %	MW	MVA_{SC}	dV %
Lena	230	99	1348	7.3	50	1348	3.7
			608	16.3		608	8.2

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 11 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 TSIR minimum voltage control requirements will most likely be acceptable. For Lena 230 kV, a wind farm larger than 12 MW (0.02*608) may require more voltage control capability than the minimum TSIR requirements.

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 interconnection is calculated for each case and is summarized in Table 12.

Table 12: Change in voltage following loss of wind generation plant.

Location	kV	MW	dV1 %	dV2 %	dV3 %
Lena	230	99	0.90%	4.60%	2.60%
		50	0.20%	2.04%	1.20%

Table 12 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.

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 site 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 Lena 230 kV. Further investigation into voltage control requirements above the minimum requirements would be performed in the Interconnection Facilities Study phase.

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 site.

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 beyond the minimum TSIR requirements may be required on a wind farm connected to 230 kV line G82R if it is larger than 12 MW based on a maximum 2% voltage change criterion for plant loss. Further investigation would be required in an Interconnection Facilities Study phase.

9.0 Transmission Facility Costs

9.1 Introduction

The transmission facility costs to connect the wind farm to 230 kV line G82R near Lena are calculated for planning purposes. Typical unit costs for equipment are used. A more detailed good faith cost estimate would be developed if the study proceeds to the Interconnection Facility Study phase.

9.2 Costs to Tap line G82R at Lena

Table 13 summarizes the planning level cost estimate for tapping 230 kV line G82R at Lena and sectionalizing the line with a three-breaker ring bus. The connection costs are the same for a 50 MW or 99 MW wind farm.

Table 13. Lena 230 kV: Interconnection Facilities Cost Estimate

Item	Cost
New 230 kV Station at Lena	$3,000,000
3 – 230 kV circuit breaker terminations	$8,700,000
1.6 km 230 kV line from the wind farm to lineG82R	$440,000
G82R outage during wind farm installation ($40/MWh for 200 MW for estimated 2 weeks)	$2,688,000
Total	**$14,828,000**

9.3 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. At least 6 months will be required to complete the Interconnection Facilities Study, investigate impacts on Ontario and U.S. facilities and obtain an amendment to our National Energy Board license to allow changes to an international tie line. The earliest possible in-service date is October 31, 2005. This date is preliminary and would be confirmed during the Interconnection Facilities Study.

10.0 References

[1] Manitoba Hydro report, "St. Leon Interconnection Evaluation Study", July 2003, http://oasis.midwestiso.org/documents/Mheb/queue.html.

Appendix A
Minimum and Maximum Transient Voltage

Lena 230 kV connection - wind on

Appendix A
Min and Max Transient Voltage

Case No.	Case Name	Prior Outage	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

(yellow) - Voltage violation (MH - post fault < 0.7pu) **Bold** NEG Micon - Grid connection 100 ms voltage violation (<0.85 pu or > 1.125 pu)