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Borden Ladner Gervais

July 17, 2013

Delivered by Email and Courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
26th Floor, Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Application for Leave to Construct – Grand Bend Wind Limited Partnership
Board File No. EB-2013-0185

We are counsel to Grand Bend Wind Limited Partnership (the "Applicant") in the above-captioned matter.

Please find accompanying this letter the Applicant's responses to Board Staff interrogatories. Please do not hesitate to contact me should you have any questions or require further information.

Yours very truly,

BORDEN LADNER GERVAIS LLP
Per:

Original signed by James C. Sidlofsky

James C. Sidlofsky
Encl.

copy to: Gordon Potts, Northland Power Inc.
Intervenors of Record

EB-2013-0185

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c.15, Schedule B;

AND IN THE MATTER OF an application by Grand Bend Wind Limited Partnership for an order or orders pursuant to section 92 of the *Ontario Energy Board Act, 1998* granting leave to construct transmission facilities in an Area Northwest of Grand Bend.

GRAND BEND WIND LIMITED PARTNERSHIP RESPONSES TO BOARD STAFF INTERROGATORIES

July 17, 2013

BUSINESS AND CORPORATE STRUCTURE

Interrogatory 1

References

(1) Exh. B, Tab 1, Sch. 1

(2) Exh B, Tab 1, Sch. 2

Paragraph 1 in the Reference (1) indicates that Grand Bend Wind Limited Partnership is the Applicant. Paragraph 6 and other references in the evidence refer to “the Applicants”.

Paragraph 17 of Reference (1) states that the transmission facilities will be owned by Grand Bend Wind Limited Partnership and that Northland Power Inc. will be responsible for the operation and maintenance of the Transmission Facilities pursuant to the terms of an Operations, Management and Maintenance Agreement.

The Chart in Reference (2) shows the intended corporate structure upon satisfaction of “Conditions Precedent”

Questions/Requests:

(a) Please clarify who the Applicant(s) is (are)?

(b) What is the status of any agreements needed between FNP and Northland Power Inc. (NPI) to achieve the ownership structure shown in Reference (2)?

(c) When does the Applicant(s) expect FNP to be issued 50% ownership in the Applicant and the applicant general partner as indicated in Reference (2)?

Response:

(a) The Applicant is Grand Bend Wind Limited Partnership. The reference in paragraph 6 incorrectly pluralizes the word Applicant.

(b) The agreements needed between FNP and NPI were signed in February 2013 and are in full force.

(c) The Applicant expects FNP to be issued 50% ownership in the Applicant and the Applicant's general partner in Q4 2013.

DESCRIPTION AND LOCATION OF THE PROJECT

Interrogatory 2

Reference: Exh. B, Tab 1, Sch. 1, page 2

Paragraph 8 in the reference indicates that "a "step-up" transformer will be used at each wind turbine generator ("WTG") to transform the electricity generated at the WTG 690 V to 34.5 kV…." The line drawing in Exh B, Tab 2, Sch 3 shows a total of 3 step-up transformers, each connecting a group of 14-17 turbines.

Questions/Requests

(a) Please confirm/clarify whether there is one step-up transformer per turbine or a total of 3 transformers connecting groups of turbines.

Response

(a) There will be one step-up transformer for each turbine. A corrected version of the Line Drawing originally provided at Exh. B, Tab 2, Sch 3 accompanies these responses as Attachment 2(a).

CONNECTION AGREEMENT WITH TRANSMITTER

Interrogatory 3

Reference: Exh. E, Tab 1, Sch. 1

The third paragraph in the reference indicates that the Transmission Facilities will comply with the requirements of the Hydro One Networks Inc. (HONI) Transmission Connection Agreement.

Questions/Requests

(a) Please provide the status of any connection agreement with HONI for the subject facilities including when an agreement is expected to be concluded, if applicable.

Response

(a) The draft connection agreement will be available in September 2013. A finalized agreement is anticipated in Q4, 2013.

NEED FOR THE PROJECT

Interrogatory 4

Reference: Exh. B, Tab 3, Sch. 1

The reference states that "The Applicant determined that the nearest best connection point for the Generation Project was circuit B23D near Seaforth TS. The Applicant submitted its Request for Connection Point Amendment form to the OPA on June 9, 2011. On July 5, 2011 the Applicant received a FIT Contract based on this revised connection point."

Questions/Requests

(a) Please provide a copy of the Applicant's latest Power Purchase Agreement under the Feed-In Tariff (FIT) program with the Ontario Power Authority.

Response

(a) As set out in the Application, the Applicant can confirm that it has an OPA FIT contract for 100 MW. The Applicant's version of the contract is 1.5, and the General Terms and Conditions for this version of the contract are publicly available from the Ontario Power Authority, at the following address: http://fit.powerauthority.on.ca/program-resources/program-archives

The Applicant submits that the specific commercial terms of the contract are not relevant to this leave to construct proceeding.

RENEWABLE ENERGY APPROVAL

Interrogatory 5

Reference: Exh. C, Tab 1, Sch. 1, page 2

The reference states the following: "The Ministry of Environment ("MOE") Renewable Energy Approval ("REA") for the Generation Project and Transmission Facilities was filed on February 15, 2013. As such, based on the MOE's six month service guarantee, the Applicant anticipates receiving MOE approval of the REA by the end of August, 2013."

Questions/Requests

(a) Please provide an update on the status of the Renewable Energy Approval (REA). Is approval still expected by the end of August 2013?

(b) Have there been any objections to the granting of the REA and if so, by which parties? What has been the general nature of any concerns that have been raised?

(c) Please provide a copy of the REA approval along with a copy of the REA documentation when approval is granted.

Response

(a) The REA was submitted on February 15, 2013. The Ministry of the Environment is not in a position to provide a date by which they expect to give their decision. The Applicant is aware that the delays are coming and is now targeting receipt of approval of the REA in October 2013.

(b) There have been no objections to the granting the REA as of now.

(c) The Applicant will provide a copy of the REA approval along with a copy of the REA documentation when approval is granted.

TRANSMISSION RATE IMPACT ASSESSMENT

Interrogatory 6

Reference: Exh. B, Tab 4, Sch. 1

The reference states that "The proposed Transmission Facilities are to be used solely to connect the Generation Project to the IESO-controlled grid. The Applicant will therefore not be a licensed or rate-regulated transmitter. The financial risk of constructing, owning, and operating the Transmission Facilities lies solely with the Applicant."

Questions/Requests

(a) Please confirm that the Applicant will be responsible for the total cost of the facilities proposed in this application including any modifications required on the HONI transmission system needed to accommodate the proposed facilities.

(b) For any costs in (i) not payable by the Applicant, please describe the facilities/work required, costs of these and cost responsibility including any ongoing operation and maintenance costs.

Response

(a) The Applicant confirms that it will be responsible for the total cost of the facilities proposed in this Application including any modifications required on the HONI transmission system needed to accommodate the proposed facilities.

The Applicant will replace at its cost 15 lightning arrestors on the existing HONI transmission system with arrestors of the next class higher. The maintenance costs related to these arrestors will be borne by HONI, but as they are replacing existing arrestors there will be no incremental maintenance cost to HONI.

(b) Not applicable. See the Applicant's response to question 6(a) above.

COST RESPONSIBILITY FOR STRANDED ASSETS & DECOMMISSIONING

Interrogatory 7

Reference: Exh. B, Tab 4, Sch. 1

Questions/Requests

(a) Please acknowledge the Applicant's responsibility for removing the transmission and related facilities if construction of these transmission facilities does not proceed or is interrupted due to unforeseen events such as the inability to acquire or secure the various permits or due to a force majeure event?

(b) Did the Applicant set aside funds to address the events outlined in (iii) above leading to stranded assets and for decommissioning, or alternatively guaranteed by any other means? Please provide details.

Response

(a) The Applicant acknowledges its responsibility for removing the transmission and related facilities if construction of these transmission facilities does not proceed or is interrupted due to unforeseen events such as the inability to acquire or secure the various permits or due to a force majeure event.

(b) The Applicant has not set aside funds to address the events outlined in (a) above leading to stranded assets and for decommissioning, nor is this activity guaranteed by other means. The applicant is 50% owned by NPI, and NPI has the financial means to remove and decommission the transmission facilities if this is required.

LAND - RELATED MATTERS & OTHER APPROVALS

Interrogatory 8

References:

(1) Exh. F, Tab 1, Sch. 1

(2) Exh. F, Tab 1, Sch. 2

In Reference (1), page 1, it is stated that:

"The transmission line is primarily located in the shoulder of existing municipal and county roads within public Right of Ways (the "RoW"). Some private property is required for the Substation and Switching Station and for the segments of the transmission line that run from the Substation and Switching Station to the RoW..

"The forms of agreements in relation to the lands can be found in Exhibit F, Tab 1, Schedule 2 of this Application."

Reference (2) contains three forms of agreements.

Questions/Requests

(a) Please confirm whether the Table on page 2 of Reference 1 includes all landowners directly affected by the proposed transmission line and associated facilities, based on current information from title search? If not, please explain and update the Table accordingly.

(b) What is the status of negotiations/agreements with the municipalities affected by the proposed transmission line and associated facilities.

(c) Please describe the options that the Applicant holds with the two private owners of the lands required for the substation and switching station and provide the status/timing of any agreements needed for the project to proceed.

(d) Please describe the three forms of agreements contained in Reference (2), their differences and which lands/ type of lands they are intended for.

(e) Has each of the affected landowners been presented with form(s) of agreement? If not, does the Applicant intend to do so and when?

(f) Please provide a list of all outstanding approvals and permits needed to complete construction of the proposed facilities, including the status and expected dates for obtaining such approvals and permits.

Response

(a) The Applicant confirms that the Table on page 2 of Reference 1 includes all landowners directly affected by the proposed transmission line and associated facilities, based on current information from title search.

(b) The bulk of the Generation Project and approximately 50% of the Transmission Facility infrastructure is located in the Municipality of Bluewater. For this reason the Applicant is focused on working with the Municipality of Bluewater to develop a Road User's Agreement (RUA) which will include provisions to allow for the Transmission Facilities in the municipal right of ways. The Municipality of Bluewater is preparing a revised draft RUA which it expects to provide to the Applicant for its comments in July 2013. Once finalized, the form of RUA with the Municipality of Bluewater will be provided to the Municipalities of Huron East and West Perth for their approval.

(c) The options that the Applicant holds with the two private owners of the lands required for the substation and switching station give the Applicant the option to use these lands for the purposes described in the Application for 50 years. Additional details can be found in the redacted copy of these agreements that can be found in Exhibit F, Tab 1, Sch 2.

(d) The first agreement is the first draft RUA from the Municipality of Bluewater, the second agreement is the redacted lease agreement for the substation and the third agreement is the redacted lease agreement for the switching station.

(e) Each of the affected landowners has been presented with the form(s) of agreement.

(f) The known outstanding permits and approvals and their status as at the date of these responses are as follows:

Agency	Permit / Approval	Status	Anticipated Date of Approval
Genesee & Wyoming (formerly RailAmerica)	Utility occupancy permit for the Goderich Exeter Railway ("GEXR").	Pending submission by EPC.	Q1 2014
Ministry of Transportation (MTO)	Encroachment permit for Highway #4.	Pending submission by EPC.	Q1 2013

Ausable Bayfield Conservation Authority (ABCA)	Permits under Ontario Regulation 97/04 for watercourse crossings.	A meeting with ABCA was held on June 20, 2013 to discuss application details and review requirements. A submission according to the details of the meeting is currently being prepared.	December 15, 2013
Hydro One Networks Inc. (HONI)	Approvals for 115 kV transmission line crossing adjacent the switchyard and 500 kV transmission line crossing at Rodgerville Road, east of Goshen Line.	Pending submissions by EPC.	Q4 2013
Oil Pipeline	Crossing approval, if required.	Pending review by EPC.	Q4, 2013
Union Gas	Crossing approvals, if required.	Pending review by EPC.	Q4, 2013
Tuckersmith Communications Co-Operative Ltd.	Crossing approvals, if required.	Pending review by EPC.	Q4, 2013
Hay Communications	Crossing approvals, if required.	Pending review by EPC.	Q4, 2013
Lake Huron and Elgin Area Water Supply System	Crossing approvals, if required.	Pending review by EPC.	Q4, 2013
Ministry of the Environment	Renewable Energy Approval	Application was made on February 15, 2013 and is under review.	February 1, 2014
Municipalities of Bluewater, Huron East and West Perth	Road User Agreement	Revised draft RUA from Bluewater expected by the end of July 2013	October 2013

SYSTEM IMPACT ASSESSMENT (SIA)

Interrogatory 9

References:

(1) Exh. H, Tab 1, Sch. 1

(2) System Impact Assessment Report, CAA ID:2011-447, dated Dec 21, 2011

(3) System Impact Assessment Report Addendum, CAA ID:2011-447, dated Jan 11, 2013

Reference (1) states that a System Impact Assessment Report (SIA) (final form) was issued on December 21, 2011 based on GE wind turbines and an overhead transmission line. Subsequently the turbine type was changed to Siemens and the decision to place the transmission line underground was made. These changes are captured in the System Impact Assessment Report Addendum dated January 13, 2013.

The Addendum report is labeled as “Draft Report”.

Both the SIA and Addendum state that the IESO recommends “that a Notification of Conditional Approval for Connection be issued for the Grand Bend Wind Farm subject to the implementation of the requirements outlined in this report.”

There is no Notification of Conditional Approval included in the pre-filed evidence.

Questions/Requests

(a) Please advise whether the Applicant now has a final version of the Addendum report and if so please file it. If not, please explain.

(b) Please advise whether the Applicant now has a Notification of Conditional Approval and if so please file it. If not, please explain.

(c) Does the Applicant plan to implement all of the IESO's connection requirements contained in the final SIA report, addendum and any further updates to these documents.

(d) Please provide verification that Hydro One Networks Inc. intends to carry out the transmitter requirements outlined in the SIA report, addendum and any further updates to these documents.

Response

(a) The Applicant now has a final version of the Addendum report. A copy of the Addendum report accompanies these responses as Attachment 9(a).

(b) The Applicant has not yet received a Notification of Conditional Approval. It is expected by July 26, 2013, and the Applicant will file a copy of the Notification when it is received.

(c) The Applicant plans to implement all of the IESO's connection requirements contained in the final SIA report, addendum and any further updates to these documents.

(d) The Applicant confirms that Hydro One Networks Inc. intends to carry out the transmitter requirements outlined in the SIA report, addendum and any further updates to these documents. Verification from HONI will come with the Capital Cost Construction Agreement which will be available in draft in September 2013.

CUSTOMER IMPACT ASSESSMENT (CIA)

Interrogatory 10

References:

(1) Exh. I, Tab 1, Sch. 1

(2) Exh. I, Tab 1, Sch. 2

Reference (1) states that a Customer Impact Assessment Report (CIA) was issued in final form on January 4, 2012 based on GE wind turbines and an overhead transmission line. Subsequently the turbine type was changed to Siemens and the decision to place the transmission line underground was made. These changes are reflected in the Customer Impact Assessment Addendum dated March 22, 2013.

The Addendum report is labeled as “Draft”.

The CIA Addendum (page 12) states that “Requirements of additional studies must be met before confirmation be made that GBWF can be incorporated without adverse impact on customers supplied from circuit B23D and in the local electrical area.”

Among other requirements, the CIA addendum states that “All customers are required to check to ensure that the equipment and grounding system at their stations/facilities meet the expected increase in fault level.”

Questions/Requests

(a) Please advise whether the Applicant now has a final version of the Addendum report and if so please file it. If not, please explain.

(b) Please advise on the status of the additional studies/requirements that must be met before confirmation be made that GBWF can be incorporated without adverse impact on customers supplied from circuit B23D and in the local electrical area, including expected confirmation date.

(c) Does the Applicant plan to implement all of the connection requirements contained in the final CIA report, addendum and any further updates to these documents? If not, please explain.

(d) Please provide verification that Hydro One Networks Inc. intends to carry out any transmitter requirements outlined in the CIA report, addendum and any further updates to these documents, including expected completion dates.

(e) Please provide verification that the affected customers intend to carry out the requirements outlined in the CIA report, addendum and any further updates to these documents, including expected completion dates.

Response

(a) The Applicant now has a final version of the Addendum report. A copy of the Addendum report accompanies these responses as Attachment 10(a).

(b) The final SIA and CIA which are complete and attached confirm that the GBWF can be incorporated without adverse impact on customers supplied from circuit B23D and in the local electrical area.

(c) The Applicant plans to implement all of the connection requirements contained in the final CIA report, addendum and any further updates to these documents.

(d) The Applicant confirms that Hydro One Networks Inc. intends to carry out the transmitter requirements outlined in the CIA report, addendum and any further updates to these documents. Verification from HONI will come with the Capital Cost Recovery Agreement (CCRA) which will be available in draft in September 2013. The schedule for completion of these tasks will also be part of the CCRA.

(e) The only modification required with respect to the affected customers is the replacement of surge arrestors, which will be undertaken by HONI. Confirmation of the timing for this work will come in September 2013 with the draft CCRA.

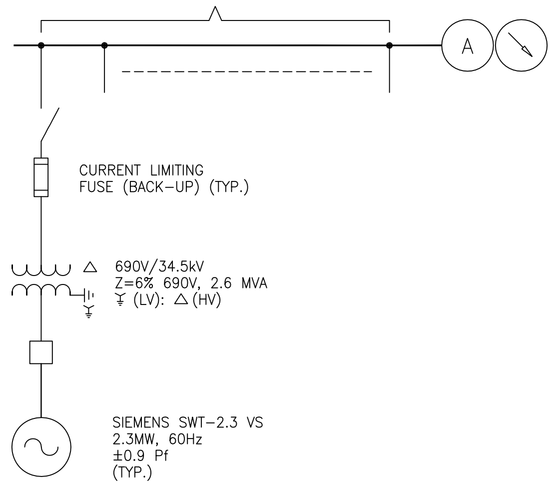
ATTACHMENT 2(a)

CORRECTED VERSION OF THE LINE DRAWING ORIGINALLY PROVIDED AT EXHIBIT B, TAB 2, SCHEDULE 3 OF THE APPLICATION

100 MW

GENERATOR DATA

Manufacture	Siemens SWT-2.3 DD
Rated Power	2300 kW
Rated Voltage	690 V
Apparent Power (pf = 1)	2300 kW
Rated Frequency	60 Hz
Power Factor	± 0.9 pf



IMPEDANCE TABLE:

1. COLLECTOR SYSTEM

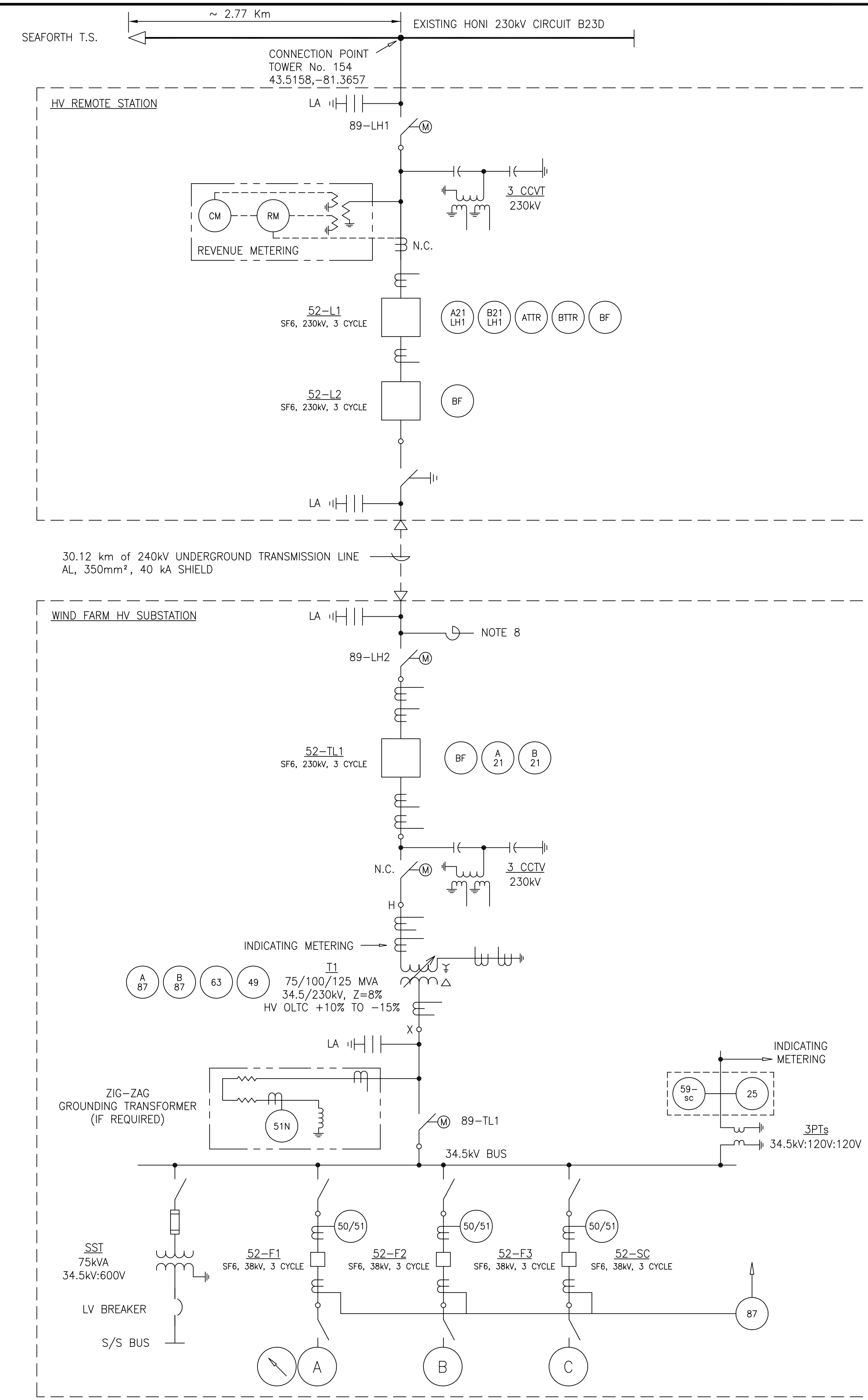
Feeder #	WTs	Generation (MW)	Equivalent Transformer (MVA)	Equivalent Transformer Z (%)	R (Ω)	X (Ω)	B (1/Ω)
A	15	31.567	39.00	0.06 +j6.00	0.783	0.7196	1398.9 x 1E^{-06}
B	14	30.571	36.40	0.06 +j6.00	0.6567	0.4534	1741.4 x 1E^{-06}
C	17	36.566	44.20	0.06 +j6.00	1.2415	1.5538	1962.8 x 1E^{-06}

2. 240 kV UNGERGROUND TRANSMISSION LINE

Positive / Negative Impedance:	Z1 = Z2 = 0.0927 +j0.1665 Ω/km
Zero Sequence Impedance:	Zo = 0.408 +j0.154 Ω/km (sheath & earth return)
Admittance:	Y = 0.0529 +j52.864 [μS/km]

NOTES:

1. Rating of 230 and 34.5 kV equipment as required by applicable standards and rules.
2. 34.5 kV outdoor or indoor type switchgear.
3. Farm electrical protection as per attached protection description and industry requirements.
4. 230 kV circuit breakers SF6 type, 3 cycles
5. 230 kV equipment rated for 250 kV max.
6. 34.5 kV collector system underground
7. 36 preselected turbines of the park will be derated for noise mitigation. It totals farm nominal output to 98.7 MW.
8. Shunt reactors will be installed to compensate cable charging. The rating of reactor shall be determined by IESO study. Reactors will be solid connected.



REVISIONS

NO	DATE	SYMBOL	REMARKS
0	JAN 19 2012		ISSUED FOR SIA/CIA APPLICATION
1	OCT 09 2012		CHANGED TO COLLECTION SYSTEM AND 230kV TRANSMISSION IMPEDANCES, 34.5kV FEEDERS CAPACITY, WT TRANSFORMER RATING FROM 2.3 TO 2.6 MVA, 230kV TRANSMISSION LINE FROM O/H TO U/G, ADDED 230kV CB AT COMMUNICATION POINT.
2	NOV 27 2012		230 kV REACTOR ADDED. IMPEDANCE OF MAIN TRANSFORMER CHANGED FROM 10% TO 8%. 230 kV CABLE SIZE CORRECTED FROM 500 mm TO 350 mm. GENERATOR TYPE CORRECTED FROM VS TO DD.
3	JULY 15 2013		MODIFIED FEEDER "A" REPRESENTATION

STAMP

PREPARED FOR

NORTHLAND POWER

PROJECT

100 MW GRAND BEND WIND FARM PROJECT

DRAWN BY	TIEN PHAM	VERIFIED BY	
SCALE	N.T.S.	VERIFIED BY	
DATE	JAN 19, 2012	APPROVED BY	C.R.

ISSUED FOR TENDER

PROJECT No.

TITLE

SINGLE LINE DIAGRAM

DRAWING No. GBWF_E-02 Rev.03

F:\Development Projects\Active Projects\Wind Projects\Ontario\Grand Bend\E-02_Rev 01 Grand Bend Wind Project SLD_Rev 03.dwg, 15/07/2013 12:00:19 PM

ATTACHMENT 9(a)

COPY OF SIA ADDENDUM REPORT

REPORT

System Impact Assessment Report Addendum

CONNECTION ASSESSMENT & APPROVAL PROCESS

Final Report

CAA ID: **2011-447**
Project: **Grand Bend Wind Farm**
Applicant: **Grand Bend Wind L.P.**

Market Facilitation Department
Independent Electricity System Operator

Date: July 8th, 2013

Document Name	System Impact Assessment Report Addendum
Issue	Final Report
Reason for Issue	Final Report
Effective Date	July 8th, 2013

System Impact Assessment Report

Acknowledgement

The IESO wishes to acknowledge the assistance of Hydro One in completing this assessment.

Disclaimers

IESO

This report has been prepared solely for the purpose of assessing whether the connection applicant's proposed connection with the IESO-controlled grid would have an adverse impact on the reliability of the integrated power system and whether the IESO should issue a notice of conditional approval or disapproval of the proposed connection under Chapter 4, section 6 of the Market Rules.

Conditional approval of the proposed connection is based on information provided to the IESO by the connection applicant and Hydro One at the time the assessment was carried out. The IESO assumes no responsibility for the accuracy or completeness of such information, including the results of studies carried out by Hydro One at the request of the IESO. Furthermore, the conditional approval is subject to further consideration due to changes to this information, or to additional information that may become available after the conditional approval has been granted.

If the connection applicant has engaged a consultant to perform connection assessment studies, the connection applicant acknowledges that the IESO will be relying on such studies in conducting its assessment and that the IESO assumes no responsibility for the accuracy or completeness of such studies including, without limitation, any changes to IESO base case models made by the consultant. The IESO reserves the right to repeat any or all connection studies performed by the consultant if necessary to meet IESO requirements.

Conditional approval of the proposed connection means that there are no significant reliability issues or concerns that would prevent connection of the proposed project to the IESO-controlled grid. However, the conditional approval does not ensure that a project will meet all connection requirements. In addition, further issues or concerns may be identified by the transmitter(s) during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with physical or equipment limitations, or with the Transmission System Code, before connection can be made.

This report has not been prepared for any other purpose and should not be used or relied upon by any person for another purpose. This report has been prepared solely for use by the connection applicant and the IESO in accordance with Chapter 4, section 6 of the Market Rules. The IESO assumes no responsibility to any third party for any use, which it makes of this report. Any liability which the IESO may have to the connection applicant in respect of this report is governed by Chapter 1, section 13 of the Market Rules. In the event that the IESO provides a draft of this report to the connection applicant, the connection applicant must be aware that the IESO may revise drafts of this report at any time in its sole discretion without notice to the connection applicant. Although the IESO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that the most recent version of this report is being used.

Hydro One

The results reported in this report are based on the information available to Hydro One, at the time of the study, suitable for a System Impact Assessment of this connection proposal.

The short circuit and thermal loading levels have been computed based on the information available at the time of the study. These levels may be higher or lower if the connection information changes as a result of, but not limited to, subsequent design modifications or when more accurate test measurement data is available.

This study does not assess the short circuit or thermal loading impact of the proposed facilities on load and generation customers.

In this report, short circuit adequacy is assessed only for Hydro One circuit breakers. The short circuit results are only for the purpose of assessing the capabilities of existing Hydro One circuit breakers and identifying upgrades required to incorporate the proposed facilities. These results should not be used in the design and engineering of any new or existing facilities. The necessary data will be provided by Hydro One and discussed with any connection applicant upon request.

The ampacity ratings of Hydro One facilities are established based on assumptions used in Hydro One for power system planning studies. The actual ampacity ratings during operations may be determined in real-time and are based on actual system conditions, including ambient temperature, wind speed and project loading, and may be higher or lower than those stated in this study.

The additional facilities or upgrades which are required to incorporate the proposed facilities have been identified to the extent permitted by a System Impact Assessment under the current IESO Connection Assessment and Approval process. Additional project studies may be necessary to confirm constructability and the time required for construction. Further studies at more advanced stages of the project development may identify additional facilities that need to be provided or that require upgrading.

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Executive Summary

Conditional Approval for Connection

Grand Bend Wind L.P. (the "connection applicant") is developing a new 98.7 MW wind power generation farm, Grand Bend Wind Farm (the "project") in Zurich, Ontario. The project will be connected to Hydro One's 230 kV circuit B23D, 2.77 km south of Seaforth TS. The project has been awarded a Power Purchase Agreement under the Feed-In Tariff (FIT) program with the Ontario Power Authority. The scheduled project in-service date is October, 2013.

This addendum updates the System Impact Assessment (SIA) "Grand Bend Wind Farm" (CAA ID 2011-447) originally issued on December 21, 2011, by taking into account project changes made after the release of the original SIA report.

The connection applicant is proposing the following modifications to the project.

- The scheduled project in-service date is changed from October, 2013 to November, 2014.
- 30 km-tap line is changed from overhead circuit to underground cable.
- Impedance for T1 230/34.5 kV transformer is changed from 10% to 8%.
- The equivalent collector impedances are changed.
- The number of turbines on each collector circuit and maximum continuous output on each collector circuit are changed.

This assessment concludes that the proposed changes are expected to have no material adverse impact on the reliability of the integrated power system. Therefore, the IESO recommends that a *Notification of Conditional Approval for Connection* be issued for the Grand Bend Wind Farm project, subject to implementation of the requirements outlined in this report.

IESO Requirements for Connection

Transmitter Requirements

The following requirements are applicable to the transmitter for the incorporation of the project:

Hydro One is required to review the relay settings of the 230 kV circuit B23D and any other circuits affected by the project, as per solutions identified in the PIA.

Modifications to protection relays after this SIA is finalized must be submitted to the IESO as soon as possible or at least six (6) months before any modifications are to be implemented. If those modifications result in adverse reliability impacts, the connection applicant and the transmitter must develop mitigating solutions.

Connection Applicant Requirements

The following requirements are applicable to the connection applicant for the incorporation of the project and they supersede those presented in the original SIA.

Specific requirement:

(1) The original SIA report included a requirement for the project to participate in the Bruce Special Protection Scheme (BSPS) requiring:

i. Hydro One to modify the logic of the BSPS to transmit rejection signals to your project,
ii. the procurement of duplicated and physically separated communication paths between Hydro One's central scheme and your project site, and
iii. equipment to be installed at your facility site to receive the signals and take action to trip or runback your generation.

Subsequent to releasing the SIA report, the IESO conducted detailed studies for the Bruce area and concluded that, at this time, the grid planning criteria can be met without the project participating in the BSPS.

Therefore, the IESO does not require the project to participate in the Bruce SPS at this time. For now, Hydro One does not need to modify the BSPS to transmit signals to the generation facility, and the telecommunication between Hydro One's BSPS and the project for that purpose does not need to be in place.

We however foresee that the incorporation of the generation facility in the BSPS may be required in the future. To allow for future incorporation of the project into the BSPS in a timely manner, the IESO requires that the connection applicant makes at this time the necessary provisions in the design and construction of the project to install equipment that is able to receive SPS signals from the BSPS, can automatically take action to reject or runback the generation upon receiving the SPS signals, and is able to send the arming status to the IESO via telemetry or other approved means.

Should the need arise in the future, the IESO will direct the connection applicant and Hydro One to install all the equipment required for the facility to participate in the BSPS, as described in the SIA report. We would expect the project to be available for participation in the BSPS in no more than 9 months from our direction.

(2) The project is required to have the capability to inject or withdraw reactive power continuously (i.e. dynamically) at a connection point up to 33% of its rated active power at all levels of active power output.

A 34 MVAr @220 kV of static inductive reactive compensation is required to be installed at the WF's 230 kV bus for the project to meet the reactive power requirements at the connection point. The reactor is recommended to be connected at the time of energization to avoid overvoltages.

The main transformer ULTC shall be adjusted, manually or automatically, to regulate the collector bus voltage such that it is within normal range and close to about 1 pu. The IESO may require automatic control for this ULTC if manual adjustment is too slow.

The connection applicant must be able to confirm its reactive capability as studied in this SIA during the commission tests.

General Requirements: The connection applicant shall satisfy all applicable requirements and standards specified in the Market Rules and the Transmission System Code. The following requirements summarize some of the general requirements that are applicable to the proposed project, and presented in detail in Appendix B of this report.

(1) The connection applicant shall ensure that the project has the capability to operate continuously between 59.4Hz and 60.6Hz and for a limited period of time in the region above straight lines on a log-linear scale defined by the points (0.0s, 57.0Hz), (3.3s, 57.0Hz), and (300s, 59.0Hz).

The project shall respond to frequency increase by reducing the active power with an average droop based on maximum active power adjustable between 3% and 7% and set at 4%. Regulation deadband shall not be wider than ± 0.06%. The project shall respond to system frequency decline by temporarily boosting its active power output for some time (i.e. 10 s) by recovering energy from the rotating blades, if this technology is available.

(2) The connection applicant shall ensure that the project has the capability to supply continuously all levels of active power output for 5% deviations in terminal voltage.

The project shall inject or withdraw reactive power continuously (i.e. dynamically) at a connection point up to 33% of its rated active power at all levels of active power output except where a lesser continually available capability is permitted by the IESO.

The project shall have the capability to regulate automatically voltage within ±0.5% of any set point within ±5% of rated voltage at a point whose impedance (based on rated apparent power and rated voltage) is not more than 13% from the highest voltage terminal. If the AVR target voltage is a function of reactive output, the slope $\Delta V/\Delta Q_{max}$ shall be adjustable to 0.5%. The response of the project for voltage changes shall be similar or better than that of a generation facility with a synchronous generation unit and an excitation system that meets the requirements of Appendix 4.2.

(3) The project shall have the capability to ride through routine switching events and design criteria contingencies assuming standard fault detection, auxiliary relaying, communication, and rated breaker interrupting times unless disconnected by configuration.

(4) The connection applicant shall ensure that the 230 kV equipment is capable of continuously operating between 220 kV and 250 kV. Protective relaying must be set to ensure that transmission equipment remains in-service for voltages between 94% of the minimum continuous value and 105% of the maximum continuous value specified in Appendix 4.1 of the Market Rules.

(5) The connection applicant shall ensure that the connection equipment is designed to be fully operational in all reasonably foreseeable ambient temperature conditions. The connection equipment must also be designed so that the adverse effects of its failure on the IESO-controlled grid are mitigated. This includes ensuring that all circuit breakers fail in the open position.

(6) The connection applicant shall install at the project a disturbance recording device with clock synchronization that meets the technical specifications provided by the transmitter.

(7) The connection applicant shall ensure that the new equipment at the facility be designed to withstand the fault levels in the area. If any future system changes result in an increased fault level higher than the equipment's capability, the connection applicant is required to replace the equipment with higher rated equipment capable of withstanding the increased fault level, up to maximum fault level specified in Appendix 2 of the Transmission System Code.

Appendix 2 of the Transmission System Code states that the maximum rated interrupting time for the 230 kV breakers must be ≤ 3 cycles. Thus, the connection applicant shall ensure that the installed breakers meet the required interrupting time specified in the Transmission System Code. Fault interrupting devices must be able to interrupt fault currents at the maximum continuous voltage of 250 kV.

(8) The connection applicant shall ensure that the new protection systems at the project are designed to satisfy all the requirements of the Transmission System Code and any additional requirements identified by the transmitter.

As currently assessed by the IESO, the project is not part of the Bulk Power System (BPS) and, therefore it is not designated as essential to the power system.

The protection systems within the project must only trip the appropriate equipment required to isolate the fault.

The autoreclosure of the high voltage breakers at the connection point must be blocked. Upon its opening for a contingency, the high voltage breaker must be closed only after the IESO approval is granted.

Any modifications made to protection relays after this SIA is finalized must be submitted to the IESO as soon as possible or at least six (6) months before any modifications are to be implemented on the existing protection systems.

(9) The connection applicant shall ensure that the telemetry requirements are satisfied as per the applicable Market Rules requirements. The determination of telemetry quantities and telemetry testing will be conducted during the IESO Facility Registration/Market Entry process. This includes quantities at the point of common coupling at Hydro One's B23D circuit.

(10) If revenue metering equipment is being installed as part of this project, the connection applicant should be aware that revenue metering installations must comply with Chapter 6 of the IESO Market Rules. For more details the connection applicant is encouraged to seek advice from their Metering Service Provider (MSP) or from the IESO metering group.

(11) The project must be compliant with applicable reliability standards set by the North American Electric Reliability Corporation (NERC) and the North East Power Coordinating Council (NPCC) that are in effect in Ontario as mapped in the following link: http://www.ieso.ca/imoweb/ircp/orcp.asp.

(12) The connection applicant will be required to be a restoration participant. Details regarding restoration participant requirements will be finalized at the Facility Registration/Market Entry Stage.

(13) The connection applicant must complete the IESO Facility Registration/Market Entry process in a timely manner before IESO final approval for connection is granted.

Models and data, including any controls that would be operational, must be provided to the IESO at least seven months before energization to the IESO-controlled grid. This includes both PSS/E and DSA software compatible mathematical models. The models and data may be shared with other reliability entities in North America as needed to fulfill the IESO's obligations under the Marker Rules, NPCC and NERC rules.

The connection applicant must also provide evidence to the IESO confirming that the equipment installed meets the Market Rules requirements and matches or exceeds the performance predicted in this assessment. This evidence shall be either type tests done in a controlled environment or commissioning tests done on-site. The evidence must be supplied to the IESO within 30 days after completion of commissioning tests. If the submitted models and data differ materially from the ones used in this assessment, then further analysis of the project will need to be done by the IESO.

At the sole discretion of the IESO, performance tests may be required at generation and transmission facilities. The objects of these tests are to demonstrate performance meets the IESO requirements and to confirm models and data are suitable for IESO purposes. The transmitter may also have its own testing requirements. The IESO and the transmitter will coordinate their tests, share measurements and cooperate on analysis to the extent possible.

(14) The Market Rules governing the connection of renewable generation facilities in Ontario are currently being reviewed through the SE-91 stakeholder initiative and, therefore, new connection requirements (in addition to those outlined in the SIA), may be imposed in the future. The connection applicant is encouraged to follow developments and updates through the following link: http://www.ieso.ca/imoweb/consult/consult_se91.asp.

Rationale for Conditional Approval for Connection

The following conclusions supersede those presented in the original SIA.

1. The proposed connection arrangement for the project is acceptable to the IESO.
2. The asymmetrical fault current at Bruce A 230 kV switchyard before and after the incorporation of the project will exceed the interrupting capability of the existing breakers. Hydro One has planned to replace the Bruce 230 kV breakers to improve fault current interrupting capability in the long term. Before the circuit breakers are replaced, temporary operational mitigating measures have been developed by Hydro One in collaboration with the IESO.
3. The reactive power capability of the wind turbine generators (WTGs) along with the impedance between the WTGs and the IESO controlled grid results in a reactive power deficiency at the connection point which has to be compensated with additional reactive power devices.
4. The functions of the proposed wind farm control system meet the requirements in the Market Rules except that the inertia emulation control function is commercially unavailable. The connection applicant shall install this function in the future once it is commercially available for the proposed type of wind turbine generator.
5. The voltage performance with the proposed project is expected to be acceptable under both pre-contingency and post-contingency operating conditions
6. The WTGs of the project and the power system are expected to be transiently stable following recognized fault conditions.
7. The proposed WTGs are expected to remain connected to the grid for recognized system contingencies which do not remove the project by configuration.
8. Protection adjustments identified by the Hydro One in the Protection Impact Assessment (PIA) to accommodate the project have no adverse impact on the reliability of IESO-controlled grid.
9. The relay margins on the affected circuits after the incorporation of the project conform to the Market Rules' requirements.
10. In the event of high flows eastward towards Toronto, there is a low probability of congestion that may require the connection applicant to curtail its output.

– End of Section –

1. Data Verification

1.1 Connection Arrangement

The revised configuration is shown in Figure 2, Appendix A, will not reduce the level of reliability of the integrated power system and is, therefore, acceptable to the IESO

The original configuration is shown in Figure 1, Appendix A. The following changes have been made to the original configuration:

- 30 km-tap line is changed from overhead circuit to underground cable.
- Impedance for T1 230/34.5 kV transformer is changed from 10% to 8%.
- The equivalent collector impedances are changed.
- The number of turbines on each collector circuit and maximum continuous output on each collector circuit are changed as per Table 1.

Table 1: Maximum continuous output and number of turbines per collector circuit

Circuit	# of Turbines	Total Output (MW)
C1	15	31.567
C2	14	30.571
C3	17	36.566

1.2 Connection Equipment

The following tables summarize the specifications of the switches and breakers.

Table 2: Specifications for 230 kV Switches

Identifier	Maximum Continuous Voltage Rating	Continuous Current Rating	Short Circuit Symmetrical Rating
-	250 kV	1200 A	50 kA
-	250 kV	1200 A	50 kA
-	250 kV	1200 A	50 kA

Table 3: Specifications for 230 kV breakers

Identifier	Maximum Voltage Rating	Interrupting time	Continuous Current Rating	Short Circuit Symmetrical Ratings
-	250 kV	50 ms	1200 A	50 kA
-	250 kV	50 ms	1200 A	50 kA

1.3 Step-Up Transformers

The following tables summarize the new data for transformer T1. Note, the specifications for the 34.5/0.69 kV transformers have remained unchanged.

Table 4: Transformer T1

Transformation	Rating (MVA) (ONAN/ONAF/ONAF)	Positive Sequence Impedance (pu) S_B= 75 MVA	Configuration		Zero Sequence Impedance (pu) S_B= 75 MVA	Tap
			HV	LV		
230/34.5 kV	75/100/125MVA	0.00+j0.08	Yg	Delta	-	ULTC@ HV: 17 steps, 226-251.5 kV

1.4 Collector System

The following table summarizes the new collector system impedances.

Table 5: Equivalent impedance of collector circuits

Circuit	Unit #	Positive- Sequence Impedance (pu, S_B=100 MVA)			Zero- Sequence Impedance (*) (pu, S_B=100 MVA)		
		R	X	B	R	X	B
C1	15	0.065784	0.060458	0.016650	-	-	-
C2	14	0.055173	0.038093	0.020727	-	-	-
C3	17	0.104306	0.130527	0.023362	-	-	-

(*) Zero-sequence impedance has not been provided. Typical data was assumed for the SIA. The applicant needs to provide these data during the IESO Market Entry process.

1.5 Tap Line

The following table summarizes the revised impedance for circuit L1 as a result of the equipment change.

Table 6: 230 kV underground transmission cable specifications

Circuit	Positive Sequence Impedance (pu, SB=100 MVA)			Zero Sequence Impedance (pu, SB=100 MVA)		
	R	X	B	R	X	B
L1 (30 km)	0.0057459	0.010320248	0.76758528	0.0252893	0.00954545	-

– End of Section –

2. Short Circuit Assessment

Fault level studies were repeated by the transmitter to examine the effect of the project on fault levels at existing facilities in the surrounding area. Studies were performed to analyze the fault levels with and without the project and other recently committed generation projects in the system. This assessment concluded that:

(1) The interrupting capabilities of the 230 kV circuit breakers of the project are adequate for the anticipated fault levels.
(2) With the exception of the Bruce A 230 kV switchyard, the interrupting capability of the lowest rated circuit breakers near the project will not be exceeded after the incorporation of the project.
(3) The modified connection arrangement does not result in a significant difference in short circuit levels from those observed in the original SIA.

Short circuit study was carried with the assumptions documented in the original SIA report.

Table 7: Fault Levels at facilities near the project

Station	Before the Project		After the Project and other committed projects		Lowest Rated Circuit Breaker (kA)
	3-Phase	L-G	3-Phase	L-G	
*Symmetrical Fault (kA)**					
Bruce A 230 kV	43.0	54.4	44.4	55.9	65***
Detweiler 230 kV	22.9	19.8	23.6	23.1	40
Majestic B23D 230 kV	18.1	16.2	18.5	16.3	63
Grand Bend PCC 230 kV	-	-	8.2	8.3	50
Grand Bend 230 kV	-	-	6.4	6.8	50
Seaforth 115 kV	11.6	13.6	13.7	16.4	29.5
Detweiler 115 kV	24.2	27.1	24.6	28.5	39.3
*Asymmetrical Fault (kA)**					
Bruce A 230 kV	57.6	78.4**	59.5	80.5**	72.6***
Detweiler 230 kV	26.8	25.3	27.7	29.5	42.1
Majestic 230 kV	21.8	18.3	22.1	18.4	66.3
Grand Bend PCC 230 kV	-	-	9.7	10.2	(unknown)****
Grand Bend 230 kV	-	-	6.9	7.7	(unknown)****
Seaforth 115 kV	12.9	16.0	15.5	19.6	34.1
Detweiler 115 kV	28.1	33.3	28.6	35.3	45.4

* Based on a pre-fault voltage level of 550 kV for 500 kV buses, 250 kV for 230 kV buses, and 127 kV for 115 kV buses.
**The asymmetrical fault level is based on a breaker contact parting time of 44 ms.
***Three lower rated Bruce A 230 kV breakers (D1L81, K1L82 and L23T25) are scheduled to be replaced by December 2012 (see CAA ID#2010-EX511). The listed lowest rated circuit breaker value for Bruce A 230 kV assumes these breakers being replaced.
****The applicant must provide the asymmetrical rating of the 230 kV circuit breakers during the IESO Market Entry process.

The results also show that the line-to-ground asymmetrical fault current at Bruce A 230 kV before and after the incorporation of the project and other committed projects will exceed the interrupting capability of the existing breakers. This issue has been investigated in the 2nd SIA addendum for the project of Bruce G1 and G2 restart (CAA ID 2004-163), where the IESO has identified a requirement to replace all the Bruce 230 kV breakers with higher fault current interrupting capability and assessed potential mitigation measures for this issue until these circuit breakers are replaced. Hydro One has planned to replace the Bruce 230 kV breakers.

– End of Section –

3. System Impact Studies

3.1 Reactive Power Capability

The reactive power capability test was repeated to ensure that the project is still capable of injecting and withdrawing up to 33% of its rated active power at the connection point (± 32.6 MVar). Results indicate that a 34 MVAr @220 kV of static inductive reactive compensation is required to be installed at the WF's 230 kV bus for the project to meet the reactive power requirements at the connection point.

Dynamic Reactive Power Capability

The following table summarizes the IESO's requirement for reactive power from each generator and the available capability of the Siemens SWT-2.3 DD 60 Hz wind turbine, at rated terminal voltage and rated active power. Figure 3 in Appendix A shows the reactive power capability of the generator. It is concluded that the Siemens SWT-2.3-DD WTGs can deliver the IESO required dynamic reactive power at rated terminal voltage. Thus there is no need to install an additional dynamic reactive power device.

Table 8: Grand Bend WF dynamic reactive power capability at the connection point

	Rated Voltage	Rated Active Power	Reactive Power Capability	Power Factor
IESO Requirements	690 V	2.3 MW	Q_{max} = 2.3 x tan[cos^{-1}(0.9)] = 1.114 MVAr	0.9 lag
			Q_{min} = -2.3 x tan[cos^{-1}(0.95)] = -0.756 MVAr	0.95 lead
Siemens SWT-2.3 DD 60 Hz	690 V	2.3 MW	Q_{max} = 1.481 MVAr	0.84 lag
			Q_{min}= -1.465 MVAr	0.84 lead

Static Reactive Power Capability

The total amount of static reactive required was determined through two tests. The first test determines the amount of static reactive compensation required to help maintain typical low and high voltages at the connection point. This test allows for the aid of under load tap changer action from transformer(s). The second test determines the amount of static reactive compensation required at the facility in order to provide the full reactive capability requirements at the connection point under a ± 10% change voltage change at the connection point without the aid of under load tap changer action from transformer(s). The test which yields the larger static reactive compensation will determine the required amount that must be installed at the project.

(a) Static reactive compensation test: maintain typical high and low voltages

The reactive power capability in lagging power factor of the project was assessed under the following assumptions:

- typical low voltage of 236 kV at the connection point;
- maximum active power output from the equivalent WTG;
- maximum reactive power output (lagging power factor) from the equivalent WTG, unless limited by the maximum acceptable WTG terminal voltage. The reactive capability is adjusted based on the terminal voltage as per Figure 3;
- maximum acceptable WTG voltage is 1.1, as per WTG voltage capability;

- the 230/34.5 kV step-up transformer ULTC is available to adjust the LV voltage as close as possible to 1 pu voltage;

The reactive power capability in leading power factor of the project was assessed under the following assumptions:

- typical high voltage of 242 kV at the connection point;
- maximum active power output from the equivalent WTG; (worst case scenario for Siemens WT)
- maximum reactive power consumption (leading power factor) from the equivalent WTG, unless limited by the minimum acceptable WTG terminal voltage; The reactive capability is adjusted based on the terminal voltage as per Figure 3.
- minimum acceptable WTG voltage is 0.9, as per WTG voltage capability;
- the 230/34.5 kV step-up transformer ULTC is available to adjust the LV voltage as close as possible to 1 pu voltage;

The IESO's reactive power calculation used the equivalent electrical model for the WTG and collector feeders as provided by the connection applicant. It is very important that the WF has a proper internal design to ensure that the WTG are not limited in their capability to produce active and reactive power due to terminal voltage limits or other facility's internal limitations. For example, it is expected that the transformation ratio of the WTG step up transformers will be set in such a way that it will offset the voltage profile along the collector, and all the WTG would be able to contribute to the reactive power production of the WF in a shared amount.

Based on the equivalent parameters for the WF provided by the connection applicant and the high charging nature of the 30 km tap-line underground cable, an amount of 32 MVAr @220 kV of static inductive reactive compensation is required to be installed at the WF's 230 kV bus to meet the reactive power requirements at the connection point for this test. The results of the above test with the compensation included are summarized in Table 9.

Table 9: Grand Bend WF static reactive power capability at the connection point

Operation	Collector Bus Voltage (kV)	Generator Terminal Voltage (pu)	Reactive Power Injection at Connection Point(Mvar)	230 kV Bus Voltage At Connection Point (kV)
Lagging PF*	33.6	1.01	+ 71.2	236
Leading PF**	34.1	0.96	- 32.7	242

* 230/34.5 kV transformer tap required to be at the 251.5 kV position
** 230/34.5 kV transformer tap required to be at the 226 kV position

(b) Static reactive compensation test: impact of ± 10% voltage change

The reactive power capability in lagging power factor of the project was assessed under the following assumptions:

- A voltage of 216 kV at the connection point (10% voltage decline from average voltage of 240 kV) ;
- maximum active power output from the equivalent WTG;
- maximum reactive power output (lagging power factor) from the equivalent WTG, unless limited by the maximum acceptable WTG terminal voltage. The reactive capability is adjusted based on the terminal voltage as per the reactive capability diagram shown in Figure 3 in Appendix.

- 0.69/34.5 kV GSU equivalent transformers on all feeders on 1 pu fixed tap position;
- the 230/34.5 kV step-up transformers fixed at the 238.7 kV tap position.

The reactive power capability in leading power factor of the project was assessed under the following assumptions:

- A voltage of 264 kV at the connection point (10% voltage rise from the average voltage of 240 kV) ;
- minimum (zero) active power output from the equivalent WTG;
- maximum reactive power consumption (leading power factor) from the equivalent WTG, unless limited by the minimum acceptable WTG terminal voltage; the reactive capability is adjusted based on the terminal voltage as per the reactive capability diagram shown in the original report.
- 0.690/34.5 kV GSU equivalent transformers on all feeders on 1 pu fixed tap position;
- the 230/34.5 kV step-up transformers fixed at the 238.7 kV tap position. .

Based on the equivalent parameters for the WF provided by the connection applicant and the high charging nature of the 30 km tap-line underground cable, an amount of 34 MVAr @220 kV of static inductive reactive compensation is required to be installed at the WF's 230 kV bus to meet the reactive power requirements at the connection point for this test. The results of the above test with the compensation included are summarized in Table 10 below.

Table 10: Grand Bend WF reactive power capability at the connection point

Operation	Collector Bus Voltage (kV)	Generator Terminal Voltage (pu)	Reactive Power Injection at Connection Point(Mvar)	230 kV Bus Voltage At Connection Point (kV)
Lagging PF*	32.7	1	+ 64.5	215.8 kV
Leading PF**	35	0.98	- 33.1	263.6 kV

The second static reactive compensation test yielded a larger amount of static reactive compensation required that must be installed at the project. Therefore a 34 MVAr @220 kV of static inductive reactive compensation is required to be installed at the WF's 230 kV bus for the project to meet the reactive power requirements at the connection point.

The IESO's reactive power calculation used the equivalent electrical model for the WTG and collector feeders as provided by the connection applicant. It is very important that the WF has a proper internal design to ensure that the WTG are not limited in their capability to produce active and reactive power due to terminal voltage limits or other project's internal limitations. For example, it is expected that the transformation ratio of the WTG step up transformers will be set in such a way that it will offset the voltage profile along the collector, and all the WTG would be able to contribute to the reactive power production of the WF in a shared amount.

The connection applicant needs to provide "as-built" data during the IESO Market Entry process. The IESO will review the required amount of static reactive power compensation at that time. Should the amount of static reactive compensation significantly differ from what was determined in this SIA, the IESO may require the connection applicant to install additional static reactive devices.

The capability of the project to provide the full range of reactive capability will require the ULTC tap positions of the 230/34.5 kV transformer to be changed in response to system conditions. Thus, the IESO requires that the 230/34.5 kV transformer ULTC be adjusted, manually or automatically, to regulate the collector bus voltage such that it is within its normal range and close to about 1 pu. This would facilitate the WTG's ability to provide full reactive support in response to system conditions. The IESO may require automatic control for this ULTC if manual adjustment is too slow.

3.2 Tap-line Cable Switching Analysis

The IESO requires the voltage changes shall not normally exceed 10% of steady state rms for line switching operations. A switching study was carried out to investigate the effects on system voltages when switching in the underground tap-line cable. To reflect reasonable restrictive system conditions, the voltage change study was conducted under the light load condition and assumed that circuit B22D is out of service. Moreover, a sensitivity analysis was conducted to examine the pre-switching voltage limit to avoid overvoltages at Grand Bend WF's 230 kV bus and its point of common coupling (PCC).

Table 11: Tap-Line Cable Switching Study Results

Pre-switching voltage at PCC (kV)	Bus	With 34 MVAr Reactor		Without 34 MVAr Reactor	
		Post-switching (kV)	ΔV (%)	Post-switching (kV)	ΔV (%)
236	GB WF	241.2	2.2	246.4	4.4
	GB PCC	241.1	2.2	245.4	4.0
238	GB WF	243.4	2.2	248.6	4.4
	GB PCC	243.3	2.2	247.6	4.0
240	GB WF	245.4	2.3	250.7	4.5
	GB PCC	245.3	2.2	249.7	4.0
242	GB WF	247.4	2.3	252.8	4.5
	GB PCC	247.3	2.2	251.8	4.1
244	GB WF	249.7	2.3	255.1	4.5
	GB PCC	249.6	2.2	254.1	4.1
246	GB WF	251.7	2.3	257.1	4.5
	GB PCC	251.6	2.2	256.1	4.1

The results show that switching the cable, with or without the compensation reactor identified in section 3.1, produces a less than 10% voltage change at the PCC. It has been demonstrated that energizing the cable when the reactor is out-of-service and the voltage at the PCC is above 238 kV may result in voltages above 250 kV at the wind farm and at the PCC. With the reactor in-service, the cable may be energized at voltages up to 244 kV at the PCC without resulting in voltages above 250 kV. Therefore, the reactor is recommended to be connected at the time of energization to avoid overvoltages. Alternatively, equipment capable to withstand voltages above 250 kV could be installed at the PCC and within the wind farm.

3.3 Thermal Analysis

It was determined that the thermal analysis and conclusions presented in the original SIA are still valid and therefore, a repeat of study was not necessary for this addendum.

The original SIA concluded that there are no local area pre-contingency or post-contingency thermal overload issues after the incorporation of the project.

3.4 Voltage Analysis

It was determined that the voltage analysis and conclusions presented in the original SIA are still valid and therefore, a repeat of study was not necessary for this addendum.

The original SIA concluded that the study results indicate that system voltages after the integration of the project are within the criteria under both pre- and post-contingency conditions and all voltage changes are within the IESO's criteria of 10%.

3.5 Transient Stability Performance

Transient simulations were repeated to account for the modifications as per this addendum. Results were not significantly different from those presented in the original SIA and, therefore, not presented in this addendum.

The original SIA concluded that the transient responses show that the generators remain synchronized to the power system and the oscillations are sufficiently damped following all simulated contingencies. It can be concluded that, with Grand Bend Wind Farm on-line, none of the simulated contingencies caused transient instability or un-damped oscillations.

3.6 Voltage Ride-Through Capability

It was determined that the voltage ride-through capability analysis and conclusions presented in the original SIA are still valid and therefore, a repeat of study was not necessary for this addendum.

The original SIA concluded that the proposed WTGs are able to remain connected to the grid for recognized system contingencies that do not remove the project by configuration.

However, when the project is incorporated into the IESO-controlled grid, if actual operation shows that the WTGs trip for contingencies for which they are not removed by configuration, the IESO will require the voltage ride-through capability be enhanced by the applicant to prevent such tripping.

The voltage ride-through capability must also be demonstrated during commissioning by monitoring several variables under a set of IESO specified field tests and the results should be verifiable using the PSS/E model.

3.7 Relay Margin

Due to high relay margin observed in the original SIA, it was determined that a repeat of study was not necessary for this addendum.

The original SIA concluded that the impedance trajectory of circuit B23D does not penetrate the relay characteristic and has a margin of greater than 20%, thereby meeting the Market Manual requirement.

– End of Section –

Appendix A: Figures

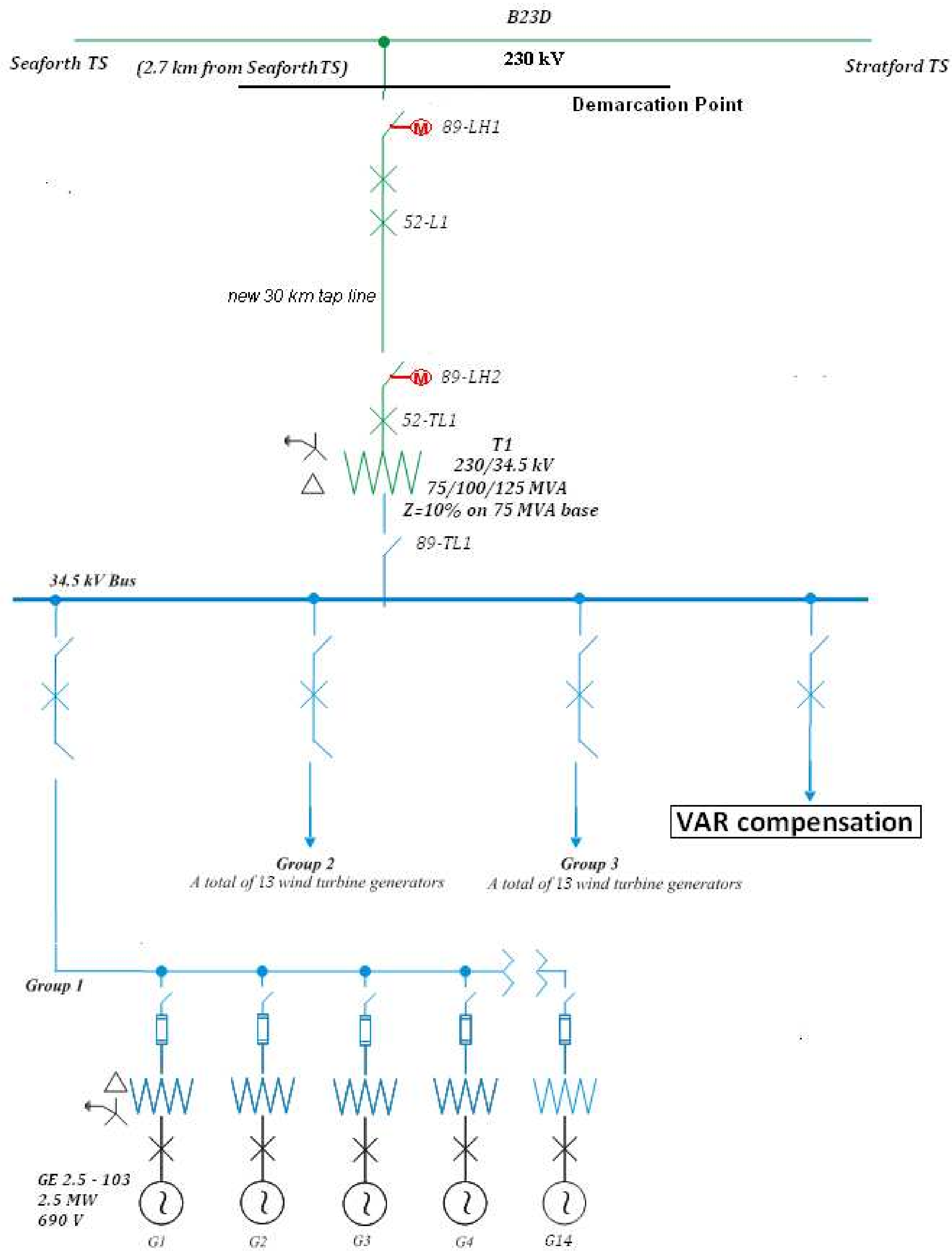


Figure 1: Original Grand Bend WF Configuration

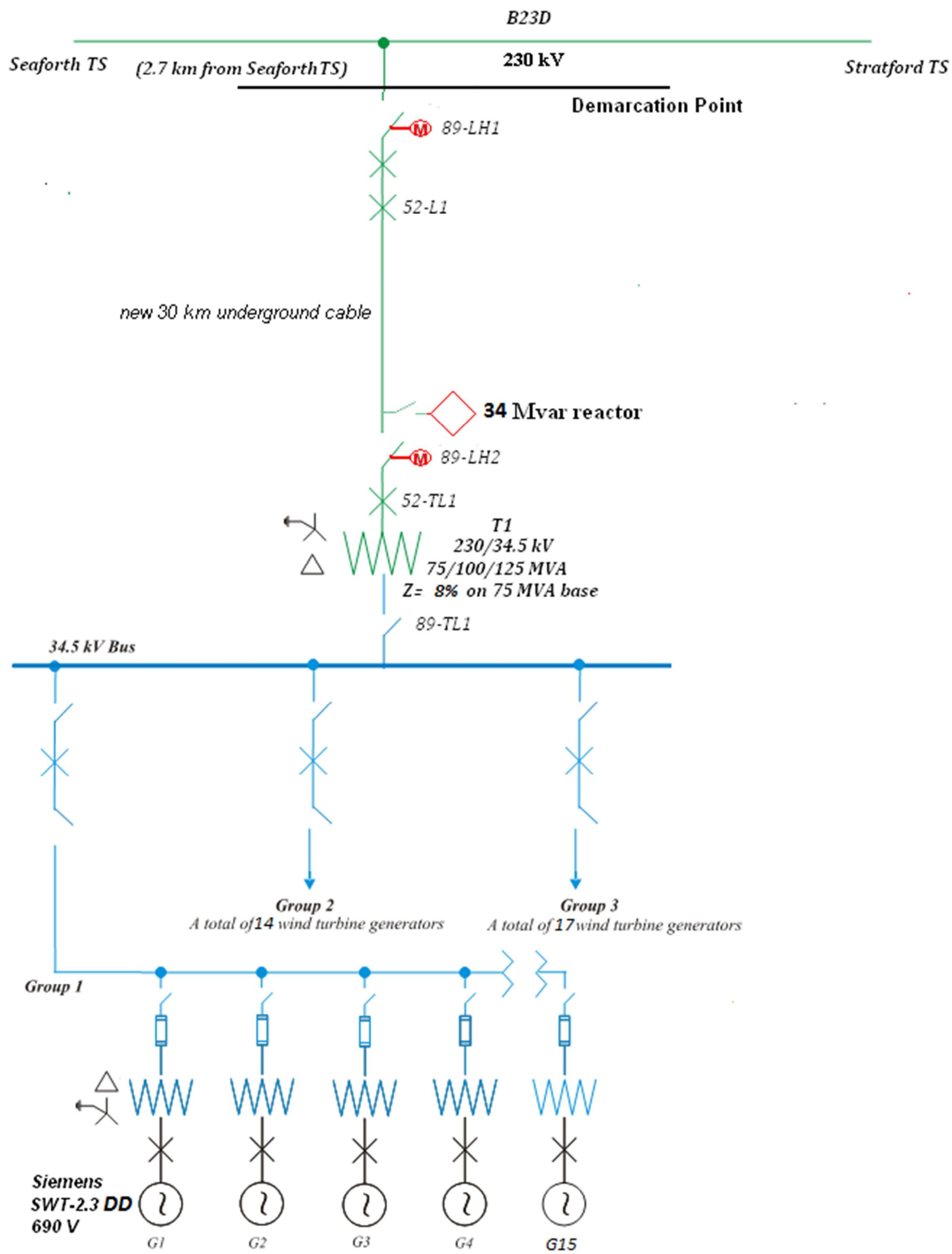


Figure 2: Modified Grand Bend WF Configuration

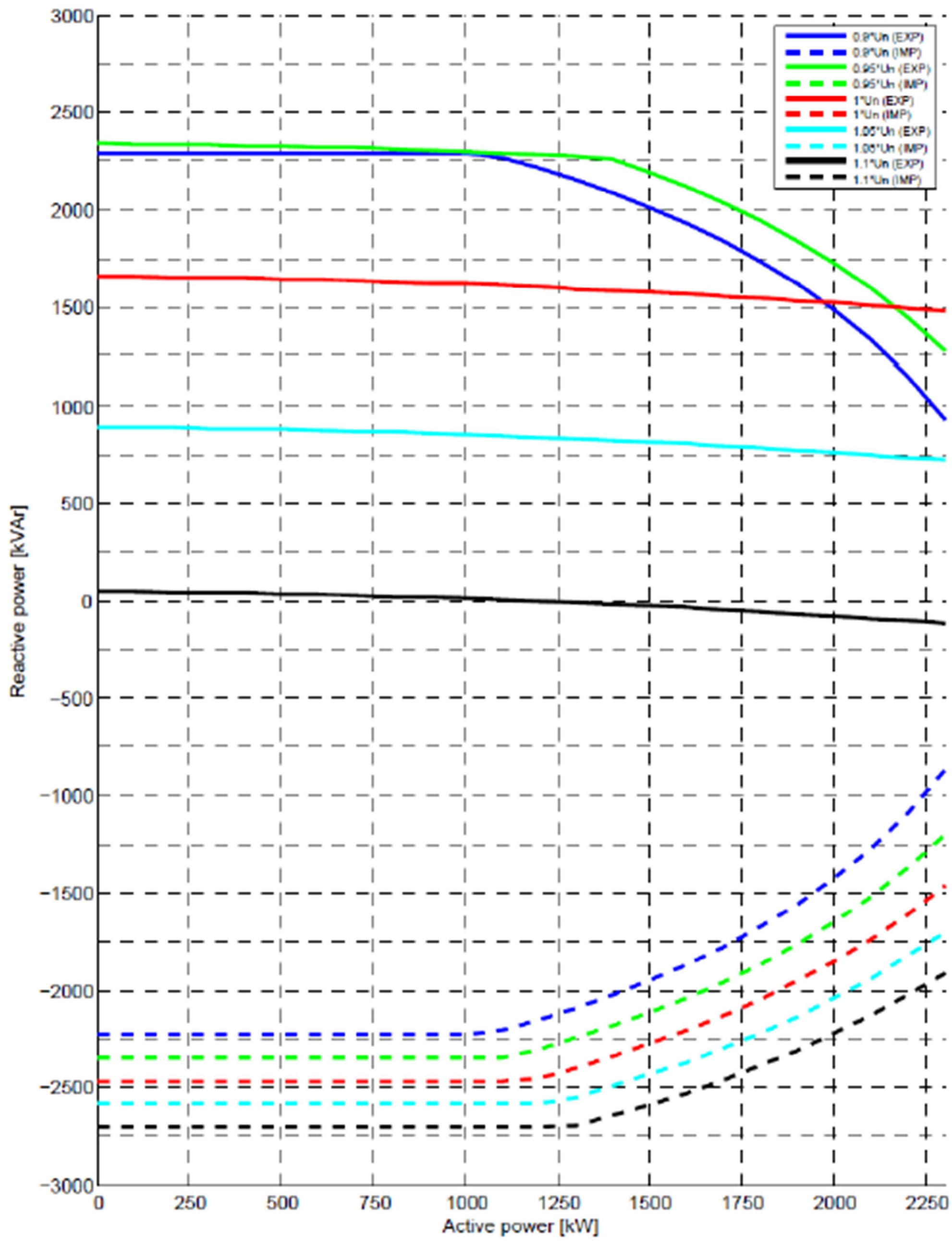


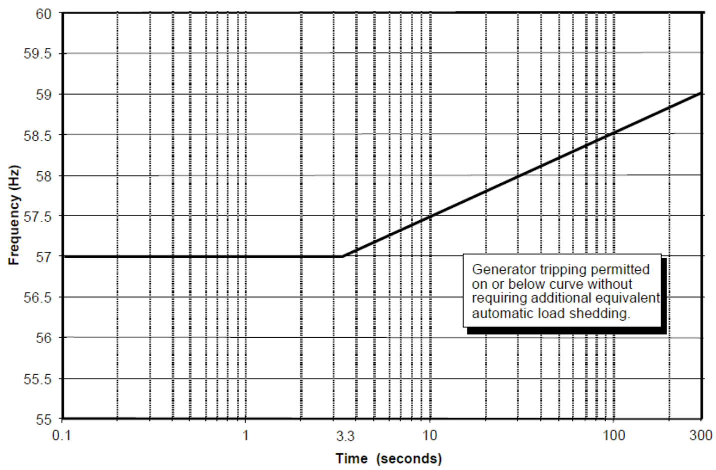
Figure 3: Reactive power limits curves for the SWT -2.3 DD 60 Hz wind turbine at LV side of wind turbine transformer.

Appendix B: General Requirements

The connection applicant shall satisfy all applicable requirements and standards specified in the Market Rules and the Transmission System Code. The following sections highlight some of the general requirements that are applicable to the proposed project.

a. Frequency/Speed Control

As per Appendix 4.2 of the Market Rules, the connection applicant shall ensure that the generation project has the capability to operate continuously between 59.4 Hz and 60.6 Hz and for a limited period of time in the region above straight lines on a log-linear scale defined by the points (0.0 s, 57.0 Hz), (3.3 s, 57.0 Hz), and (300 s, 59.0 Hz), as shown in the following figure.



The project shall respond to frequency increase by reducing the active power with an average droop based on maximum active power adjustable between 3% and 7% and set at 4%. Regulation deadband shall not be wider than ± 0.06%. The generation project shall respond to system frequency decline by temporarily boosting its active power output for some time (i.e. 10 s) by recovering energy from the rotating blades. This usually refers to “inertia emulation control” function within the wind farm control system. It is not required for wind facilities to provide a sustained response to system frequency decline. The connection applicant will need to indicate to the IESO whether the function of inertia emulation control is commercially available for the proposed type of wind turbine generator at the time when the wind farm comes into service. If this function is available, the connection applicant is required to implement it before the new project can be placed in-service. If this function is commercially unavailable, the IESO reserves the right to ask the connection applicant to install this function in the future, once it is commercially available for the proposed type of wind turbine generator.

b. Reactive Power/Voltage Regulation

The generation project is directly connected to the IESO-controlled grid, and thus, the connection applicant shall ensure that the project has the capability to:

- supply continuously all levels of active power output for 5% deviations in terminal voltage. Rated active power is the smaller output at either rated ambient conditions (e.g. temperature, head, wind speed, solar radiation) or 90% of rated apparent power. To satisfy steady-state reactive power requirements, active power reductions to rated active power are permitted;

- inject or withdraw reactive power continuously (i.e. dynamically) at a connection point up to 33% of its rated active power at all levels of active power output except where a lesser continually available capability is permitted by the IESO. If necessary, shunt capacitors must be installed to offset the reactive power losses within the project in excess of the maximum allowable losses. If generators do not have dynamic reactive power capabilities, dynamic reactive compensation devices must be installed to make up the deficient reactive power;
- regulate automatically voltage within ±0.5% of any set point within ±5% of rated voltage at a point whose impedance (based on rated apparent power and rated voltage) is not more than 13% from the highest voltage terminal. If the AVR target voltage is a function of reactive output, the slope $\Delta V/\Delta Q_{max}$ shall be adjustable to 0.5%. The response of the generation project for voltage changes shall be similar to or better than the response of a generation project with a synchronous generation unit and an excitation system that meets the requirements of Appendix 4.2.

c. Voltage Ride Though Capability

The generation project shall have the capability to ride through routine switching events and design criteria contingencies assuming standard fault detection, auxiliary relaying, communication, and rated breaker interrupting times unless disconnected by configuration.

d. Voltage

Appendix 4.1 of the Market Rules states that under normal operating conditions, the voltages in the 230 kV system in southern Ontario are maintained within the range of 220 kV to 250 kV. Thus, the IESO requires that the 230 kV equipment in southern Ontario must have a maximum continuous voltage rating of at least 250 kV.

Protective relaying must be set to ensure that transmission equipment remains in-service for voltages up to 5% above the maximum continuous value specified in Appendix 4.1 of the Market Rules, to allow the power system to recover from transient disturbances.

e. Connection Equipment Design

The connection applicant shall ensure that the connection equipment is designed to be fully operational in all reasonably foreseeable ambient temperature conditions. The connection equipment must also be designed so that the adverse effects of its failure on the IESO-controlled grid are mitigated. This includes ensuring that all circuit breakers fail in the open position.

f. Disturbance Recording

The connection applicant is required to install at the project a disturbance recording device with clock synchronization that meets the technical specifications provided by the transmitter. The device will be used to monitor and record the response of the project to disturbances on the 230 kV system in order to verify the dynamic response of generators. The quantities to be recorded, the sampling rate and the trigger settings will be provided by the transmitter.

g. Fault Level

The Transmission System Code requires the new equipment to be designed to withstand the fault levels in the area where the equipment is installed. Thus, the connection applicant shall ensure that the new equipment at the facility is designed to withstand the fault levels in the area. If any future system changes result in an increased fault level higher than the equipment’s capability, the connection applicant is required to replace the equipment with higher rated equipment capable of withstanding the increased fault level, up to maximum fault level specified in the Transmission System Code. Appendix 2 of the Transmission System Code establishes the maximum fault levels for the transmission system. For the 230 kV system, the maximum 3 phase symmetrical fault level is 63 kA and the maximum single line to ground symmetrical fault level is 80 kA (usually limited to 63 kA).

Appendix 2 of the Transmission System Code states that the maximum rated interrupting time for the 230 kV breakers must be ≤ 3 cycles. Thus, the connection applicant shall ensure that the installed breakers meet the required interrupting time specified in the Transmission System Code. Fault interrupting devices must be able to interrupt fault currents at the maximum continuous voltage of 250 kV.

h. Protection System

The connection applicant shall ensure that the protection systems are designed to satisfy all the requirements of the Transmission System Code as specified in Schedules E, F and G of Appendix 1 and any additional requirements identified by the transmitter. New protection systems must be coordinated with the existing protection systems.

Facilities that are essential to the power system must be protected by two redundant protection systems according to section 8.2.1a of the TSC. These redundant protections systems must satisfy all requirements of the TSC, and in particular, they must not use common components, common battery banks or common secondary CT or PT windings. As currently assessed by the IESO, this facility is not on the current Bulk Power System list, and therefore, is not considered essential to the power system. In the future, as the electrical system evolves, this facility may be placed on the BPS list.

The protection systems within the generation facility must only trip the appropriate equipment required to isolate the fault. After the facility begins commercial operation, if an improper trip of the 230 kV circuit B23D occurs due to events within the facility, the facility may be required to be disconnected from the IESO-controlled grid until the problem is resolved.

The autoreclosure of the high voltage breakers at the connection point must be blocked. Upon its opening for a contingency, the high voltage breaker must be closed only after the IESO approval is granted.

Any modifications made to protection relays after this SIA is finalized must be submitted to the IESO as soon as possible or at least six (6) months before any modifications are to be implemented on the existing protection systems. If those modifications result in adverse impacts, the connection applicant and the transmitter must develop mitigation solutions

i. Telemetry

According to Section 7.3 of Chapter 4 of the Market Rules, the connection applicant shall provide to the IESO the applicable telemetry data listed in Appendix 4.15 of the Market Rules on a continual basis. As per Section 7.1.6 of Chapter 4 of the Market Rules, the connection applicant shall also provide data to the IESO in accordance with Section 5 of Market Manual 1.2, for the purposes of deriving forecasts of the amount of energy that the project is capable of producing. The determination of telemetry quantities will be completed during the IESO Facility Registration/Market Entry process.

The data shall be provided with equipment that meets the requirements set forth in Appendix 2.2, Chapter 2 of the Market Rules and Section 5.3 of Market Manual 1.2, in accordance with the performance standards set forth in Appendix 4.19 subject to Section 7.6A of Chapter 4 of the Market Rules.

As part of the IESO Facility Registration/Market Entry process, the connection applicant must complete end to end testing of all necessary telemetry points with the IESO to ensure that standards are met and that sign conventions are understood. All found anomalies must be corrected before IESO final approval to connect any phase of the project is granted.

j. Revenue Metering

If revenue metering equipment is being installed as part of this project, the connection applicant should be aware that revenue metering installations must comply with Chapter 6 of the IESO Market Rules. For more details the connection applicant is encouraged to seek advice from their Metering Service Provider (MSP) or from the IESO metering group.

k. Reliability Standards

Prior to connecting to the IESO controlled grid, the proposed project must be compliant with the applicable reliability standards established by the North American Electric Reliability Corporation (NERC) and reliability criteria established by the Northeast Power Coordinating Council (NPCC) that are in effect in Ontario. A mapping of applicable standards, based on the proponent's/connection applicant's market role/OEB license can be found here: http://www.ieso.ca/imoweb/ircp/orcp.asp

This mapping is updated periodically after new or revised standards become effective in Ontario.

The current versions of these NERC standards and NPCC criteria can be found at the following websites:
http://www.nerc.com/page.php?cid=2|20
http://www.npcc.org/documents/regStandards/Directories.aspx

The IESO monitors and assesses market participant compliance with a selection of applicable reliability standards each year as part of the Ontario Reliability Compliance Program. To find out more about this program, write to orcp@ieso.ca or visit the following webpage: http://www.ieso.ca/imoweb/ircp/orcp.asp

Also, to obtain a better understanding of the applicable reliability compliance obligations and engage in the standards development process, we recommend that the proponent/ connection applicant join the IESO's Reliability Standards Standing Committee (RSSC) or at least subscribe to their mailing list by contacting rssc@ieso.ca. The RSSC webpage is located at:
http://www.ieso.ca/imoweb/consult/consult_rssc.asp.

l. Restoration Participant

According to the Market Manual 7.8 which states restoration participant criteria and obligations, the connection applicant will be required to be a restoration participant. Details regarding restoration participant requirements will be finalized at the Facility Registration/Market Entry Stage.

m. Facility Registration/Market Entry

The connection applicant must complete the IESO Facility Registration/Market Entry process in a timely manner before IESO final approval for connection is granted.

Models and data, including any controls that would be operational, must be provided to the IESO. This includes both PSS/E and DSA software compatible mathematical models representing the new equipment for further IESO, NPCC and NERC analytical studies. The models and data may be shared with other reliability entities in North America as needed to fulfill the IESO's obligations under the Market Rules, NPCC and NERC rules. The connection applicant may need to contact the software manufacturers directly, in order to have the models included in their packages. This information should be submitted at least seven months before energization to the IESO-controlled grid, to allow the IESO to incorporate this project into IESO work systems and to perform any additional reliability studies.

As part of the IESO Facility Registration/Market Entry process, the connection applicant must provide evidence to the IESO confirming that the equipment installed meets the Market Rules requirements and matches or exceeds the performance predicted in this assessment. This evidence shall be either type tests done in a controlled environment or commissioning tests done on-site. In either case, the testing must be done not only in accordance with widely recognized standards, but also to the satisfaction of the IESO. Until this evidence is provided and found acceptable to the IESO, the Facility Registration/Market Entry process will not be considered complete and the connection applicant must accept any restrictions the IESO may impose upon this project's participation in the IESO-administered markets or connection to the IESO-controlled grid. The evidence must be supplied to the IESO within 30 days after completion of commissioning tests. Failure to provide evidence may result in disconnection from the IESO-controlled grid.

If the submitted models and data differ materially from the ones used in this assessment, then further analysis of the project will need to be done by the IESO.

At the sole discretion of the IESO, performance tests may be required at generation and transmission facilities. The objects of these tests are to demonstrate performance meets the IESO requirements and to confirm models and data are suitable for IESO purposes. The transmitter may also have its own testing requirements. The IESO and the transmitter will coordinate their tests, share measurements and cooperate on analysis to the extent possible.

n. Other Connection Requirements

The Market Rules governing the connection of renewable generation facilities in Ontario are currently being reviewed through the SE-91 stakeholder initiative and, therefore, new connection requirements (in addition to those outlined in the SIA), may be imposed in the future. The connection applicant is encouraged to follow developments and updates through the following link:
http://www.ieso.ca/imoweb/consult/consult_se91.asp

Appendix C: PIA Report

Hydro One Networks Inc.
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Toronto, Ontario
M5G 2P5

PROTECTION IMPACT ASSESSMENT

GRAND BEND WIND FARM PROJECT

100 MW WIND FARM GENERATION CONNECTION

Date: January 10, 2013
P&C Planning Group Project #: PCT-295-PIA

Prepared By:

Hydro One Networks Inc.

Disclaimer

This Protection Impact Assessment has been prepared solely for the IESO for the purpose of assisting the IESO in preparing the System Impact Assessment for the proposed connection of the proposed generation facility to the IESO–controlled grid. This report has not been prepared for any other purpose and should not be used or relied upon by any person, including the connection applicant, for any other purpose.

This Protection Impact Assessment was prepared based on information provided to the IESO and Hydro One by the connection applicant in the application to request a connection assessment at the time the assessment was carried out. It is intended to highlight significant impacts, if any, to affected transmission protections early in the project development process. The results of this Protection Impact Assessment are also subject to change to accommodate the requirements of the IESO and other regulatory or legal requirements. In addition, further issues or concerns may be identified by Hydro One during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with the Transmission System Code legal requirements, and any applicable reliability standards, or to accommodate any changes to the IESO-controlled grid that may have occurred in the meantime.

Hydro One shall not be liable to any third party, including the connection applicant, which uses the results of the Protection Impact Assessment under any circumstances, whether any of the said liability, loss or damages arises in contract, tort or otherwise.

Revision History

Revision	Date	Change
R0	September12,2011	New Document
R1	September 28,2011	Modified Section 2.1 (General Connection Requirements)
R2	October 20, 2011	Modified Zone 1 reach at Detweiler TS & Outlined protection changes for Bruce.
R3	October 24, 2011	Revised requirements for Tele-protection.
R4	January 10, 2013	WF line changed to underground cable

PROTECTION IMPACT ASSESSMENT
GRAND BEND WF PROJECT
100 MW WIND GENERATION CONNECTION

1.0 INTRODUCTION

1.1 Protection Impact Assessment

This PIA study is prepared for the IESO to assess the potential impact of the proposed Grand Bend WF on the existing transmission protection. The primary focus of this study is on protecting Hydro One system equipment while meeting IESO System Reliability Criteria. This PIA is based on potentially connecting all new generators proposed in application ID: FIT-F9IQQSS.

1.2 Description of Proposed Connection to the Grid

Northland Power has proposed to build a 100 MVA, 60 Hz wind generating station. The generating station will be connected to HONI's 230 KV circuit, B23D (LH19), between Seaforth TS and Detweiler TS approximately 3.5 km south of Seaforth TS via a 30 km underground cable as shown in Figure 1 below.

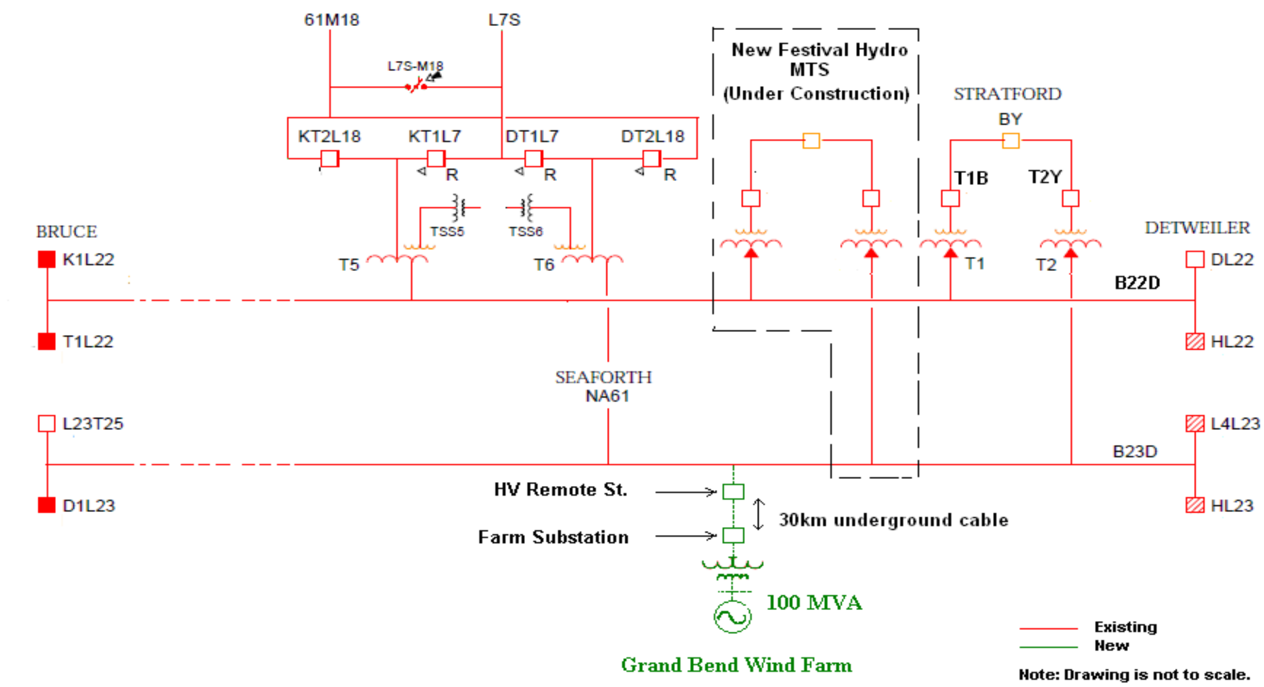

Figure 1: Grand Bend WF Connection to HONI Transmission System

2.0 PROTECTION

2.1 General

HONI circuit B23D is treated as a 3 terminal line from the protection point of view running from Bruce to Seaforth TS and from Seaforth TS to Detweiler TS; with the fault interrupting capabilities only at

Bruce and Detweiler TS. Seaforth TS is treated as a terminal station with individual protections looking towards Bruce and Detweiler TS but does not have any breakers to segment the line.

The generation from the Grand Bend WF is transported from the proponents Transformer Station (TS) to their HV Remote Station (RS) close to the point of connection via a 30km-230 KV underground cable. It is then connected to the HONI circuit through a single breaker. Such a connection presents many challenges and requires a vigilant analysis of the Hydro One circuit reliability and protection complexities arising there of.

The proposed arrangement would require a breaker failure protection to be installed at the proponents HV remote station. The increased probability of faults due to an additional 30 km of 230 KV underground cable makes the region more susceptible to instabilities; an un-cleared fault (breaker failure) on this line would trip the HONI terminal stations (Bruce and Detweiler TS) resulting in a widespread tripping of the present and future customers on that line as shown in Figure 2 below – consequently degrading the reliability of the HONI circuit. The reliability is further impacted due to the procedural complexities involved and the time required for the manual restoration of the HONI circuit after a breaker failure.

The proximity of the point of connection to the Seaforth TS (2.77 km) presents a protection challenge adding to the overall impact on the reliability of the HONI circuit, this is due to the fact that existing Zone1 protection at the Seaforth TS will need to be eliminated as the reach can not be contracted enough to exclude the proponent's connection and the new WF underground cable. In addition, the capacitive effect of the 30kM underground cable makes it more challenging for the breaker to interrupt the capacitive charging current.

It is therefore critical to devise an arrangement that will, to extent possible, mitigate the impact on the reliability of the HONI circuit. For this reason, it is required to have two breakers in series at the proponent's HV Remote Station to mitigate the frequent operation of a breaker failure protection – avoiding the widespread tripping as well as the difficulties involved in restoration of the line after a breaker failure.

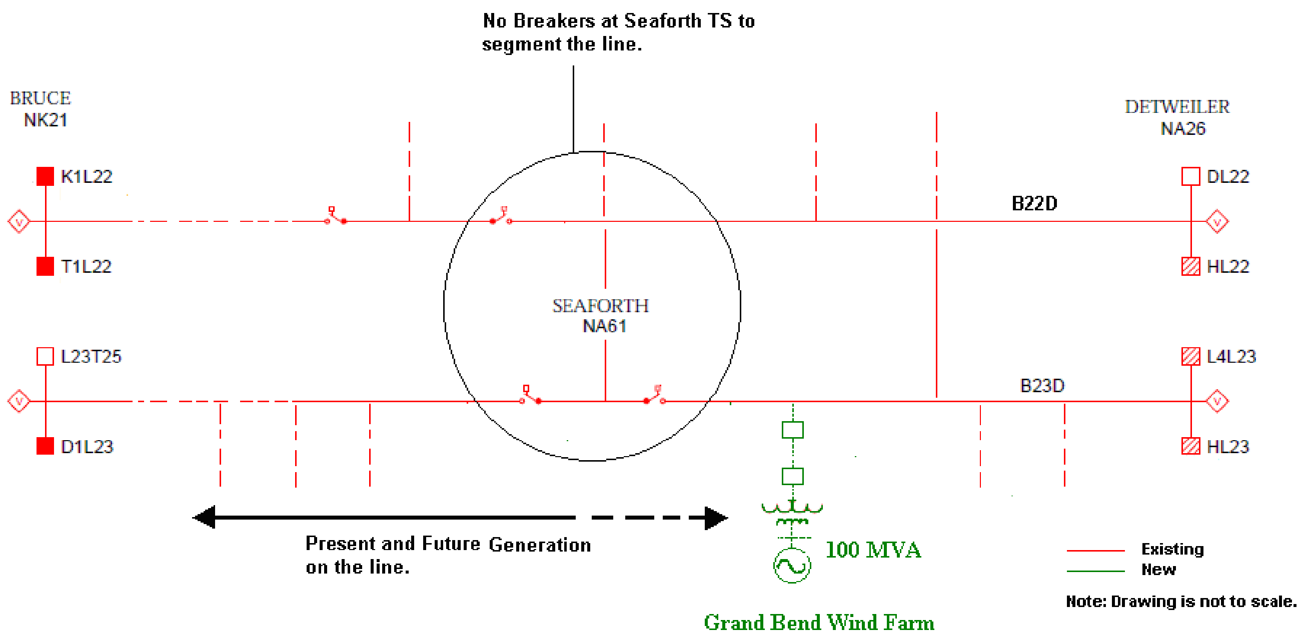

Figure 2: Breaker positions on the line B23D (LH15 & LH19)

Grand Bend WF generation is being added very close to the Seaforth TS, fault studies have shown an increase in the apparent impedance seen at the Seaforth terminal. However no significant change in the apparent impedance has been observed at the Detweiler TS.

The existing Zone1 will be eliminated at the Seaforth TS and the existing Zone 2 reach will be revised to accommodate the increased apparent impedance. The Zone 1 reach at the Detweiler TS will be reduced to exclude the proponent's connection and Zone 2 settings will be revised.

New 'A' line protections shall be installed with standard IEDs on the B23D (LH19) 230 KV circuit at Seaforth TS in order to facilitate the addition of the teleprotections for Grand Bend WF.

New communication paths are to be established from the Grand Bend HV Remote Station to the Seaforth TS and Detweiler TS to satisfy the requirements of the recommended protection schemes.

2.2 Specific Protection Requirements

Protection work to be performed is described as follows.

2.2.1 Seaforth TS

The existing electro-mechanical-based 'A' protection on line B23D will be replaced with the standard IEDs to facilitate the addition of the teleprotections for the Grand Bend WF. The existing 'B' protections shall be retained. These protections shall meet the separation requirements of NPCC Directory D4.

Grand Bend WF generation is being connected only 3.5 km south of the Seaforth TS and therefore makes it necessary to eliminate Zone 1 from this protection. The existing Permissive Overreaching Scheme between Seaforth TS and Detweiler TS shall be modified to accept a blocking signal from the Grand Bend HV RS for faults on their line. A 50 ms time delay shall be introduced in this scheme in anticipation of a blocking signal.

As suggested by the fault studies; the Zone 2 settings shall be changed to cover the maximum apparent impedance of the line due to the increased generation close to this station. Operation of the local line protection will result in transfer trips to Bruce, Detweiler Ts, Stratford TS and the Grand Bend HV RS.

2.2.2 Grand Bend Wind Farm HV Remote Station (RS)

This station will be referred to as Grand Bend HV RS hence forth. Two breakers in series shall be installed at this station. One of the benefits of double-breaker scheme is to mitigate the frequent operation of a breaker failure protection. Secondly, it is extremely hard for a circuit breaker to interrupt a capacitive changing line even though there is shunt reactor at the end of the WF underground cable.

It is customer's responsibility to provide protections to the WF line and backup protection for B23D in case that transfer trip from Hydro One station. Since zone 2 protection at Seaforth TS can see through the 230kV WF transformer and the zone 2 at Detweiler TS can see into the WF transformer, a special requirement is applied on customer's protections as below.

2.2.2.1 230 kV Line Protection for B23D

'A' and 'B' line protections for the 230 kV circuit B23D shall be installed with standard IEDs meeting separation requirements of NPCC Directory.

The zone 1 of the B23D line protection shall be set with the smaller value of following two impedances: the line impedance between Grand Bend RS and Detweiler TS or line impedance between Grand Bend HV RS and Seaforth TS plus 60% of Seaforth autotransformer impedance. The zone 2 shall be set with 125% of line impedance between Grand Bend HV RS and Bruce A TS. The zone 2 operates with 400ms delay. A zone 3 with reverse direction must be set with the farther coverage that that of the zone 2 at Seaforth TS. The purpose of the zone 3 is to send a blocking signal to Seaforth TS and Detweiler TS to keep the fast zone 2 from operating when a fault occurs in customer's line or other facilities. Hydro One will provide the setting principle to the customer. The operation of the zone 3 will send a blocking signal to both Seaforth TS and the Detweiler TS in case of a fault on the customer's line or other facility to avoid tripping of the terminal stations by the Zone 2 protections.

2.2.2.2 230 kV WF Line Protection from Grand Bend HV RS to Grand Bend HV Substation

'A' and 'B' line protections for the 230 kV underground WF cable shall be installed with standard IEDs meeting separation requirements of NPCC Directory D4. Differential line protection scheme has been proposed for this underground cable and it is the recommended scheme. The operation of the WF cable will result in cancellation of auto-reclosing since a fault on the cable would be a permanent.

The 'A' group and 'B' group will be by standard relays. Communication paths will need to be established between the Grand Bend HV RT to Seaforth TS and the Detweiler TS.

2.2.2.3 230 kV Breaker Protection

'A' and 'B' IED Trip/Close modules, alarms, status and reclose devices shall be installed for the new 230kV breakers meeting requirements of NPCC. No auto-reclosing is allowed to proceed for the receiving of TT from Seaforth TS or Detweiler TS or the operation of the WF line protection.

2.2.3 Grand Bend HV Substation

It is customer's responsibility to protect this station in coordination with what is specified in Section 2.2.2. Since zone 2 protection at Seaforth TS can see through the 230kV WF transformer and the zone 2 at Detweiler TS can see into the WF transformer, a special requirement is applied to customer's collect feeder protections as below.

1. Each feeder protection must instantaneously trip a fault on feeder;

2. When the feeder is re-energized with a fault, the feeder protection must instantaneously operate.
3. Each feeder breaker must be equipped with breaker failure function to open 230kV breaker at Grand Bend WF station.

In order to meet these requirements, distance protection is recommended for all 34.5kV feeders. The settings of the feeder protections must be coordinated with Hydro One's zone 2 at Seaforth TS. Hydro One will provide the setting principle for the feeder protections.

2.2.4 Detweiler TS

The existing 'A' and 'B' protections on the line B23D will be retained. Zone 1 reach to Seaforth TS shall be reduced 80% of the line impedance between Grand Bend RS and Detweiler TS. The POTT scheme shall be modified by delaying with 50 ms to accept the blocking signal from Grand Bend RS. Operation of the local line protection will result in transfer trips to Bruce, Seaforth TS, Stratford TS and the Grand Bend HV RS.

2.3 Tele-Protection

Seaforth TS and Detweiler TS are equipped with SONET. These communications are based on a ring configuration with path diversity. The customer must have duplicated communications with path diversity between the Grand Bend HV RS and the terminal stations.

2.4 Settings

2.4.1 Existing Settings

Table 1 summarizes the existing settings for Zones 1 and 2 on the line B23D

Station	Zone	Reach (km)	Comments
Seaforth TS (LH19)	1	65.3	Set at 80.5% of the line impedance to Detweiler TS
	2	102.1	Set at 126% of the ZMA for a fault at Detweiler TS.
Detweiler TS (LH19)	1	101.3	Set at 125% of the line impedance for a fault at Seaforth TS.
	2	101.3	Set at 125% of the line impedance for a fault at Seaforth TS.
Bruce TS (LH15)	1	88	Set at 80% of the line impedance for a fault at Seaforth TS.
	2 (Timed)	152	Set at 125% of the ZMA for a fault at Seaforth TS.

Table 1 Existing Protection Settings on the line B23D

2.4.2 Revised Settings

Table 2 summarizes the revised settings for Zones 1 and 2 on the line B23D

Station	Zone	Reach (km)	Comments
Seaforth TS (LH19)	1	n/a	Removed
	2	166.9	Set at 125% of the ZMA to Detweiler TS.
Detweiler TS (LH19)	1	59.6	Set at 80% of the line impedance to Grand Bend RS
	2	100%	Increased. Set with 125% of whole line impedance (which is larger than 125% of ZMA). Covering 100% of the line section between Seaforth and Detweiler is ensured. 100% of whole line when all infeed is eliminated.
Bruce TS (LH15)	1	88	No changed.
	2	152	No changed.

Table 2 Revised Protection Settings on the line B23D

3.0 SCADA/RTU

N/A

4.0 POWER SYSTEM MONITORING

Not in scope of the PIA. To be addressed in future.

5.0 REVENUE METERING

Not in scope of the PIA.

6.0 CYBER SECURITY

CIP-002 through CIP-009 need to be reviewed as applicable.

7.0 STATION REQUIREMENTS

N/A

8.0 UPDATE DATABASES AND DOCUMENTATION

Not in scope of the PIA. To be addressed in future.

ATTACHMENT 10(a)

COPY OF CIA ADDENDUM REPORT

Hydro One Networks Inc.
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Toronto, Ontario
M5G 2P5

- ADDENDUM -

CUSTOMER IMPACT ASSESSMENT

NORTHLAND POWER - GRAND BEND WIND FARM

100 MW WIND TURBINE GENERATION CONNECTION

Revision: 0

Date: June 25, 2013

Issued by: **Transmission System Development Division**
Hydro One Networks Inc.

Prepared by:

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Transmission System Development
Hydro One Networks Inc.

Disclaimer

This Customer Impact Assessment was prepared based on preliminary information available about the connection of the proposed Grand Bend Wind L.P. – Grand Bend Wind Farm generation facilities to be located in Zurich, Ontario. It is intended to highlight significant impacts, if any, to affected transmission customers early in the project development process and thus allow an opportunity for these parties to bring forward any concerns that they may have, including those needed for the review of the connection and for any possible application for Leave To Construct. Subsequent changes to the required modifications or the implementation plan may affect the impacts of the proposed connection identified in this Customer Impact Assessment. The results of this Customer Impact Assessment and the estimate of the outage requirements are subject to change to accommodate the requirements of the IESO and other regulatory or municipal authority requirements. The fault levels computed as part of this Customer Impact Assessment are meant to assess current conditions in the study horizon and are not intended to be for the purposes of sizing equipment or making other project design decisions. Many other factors beyond the existing fault levels go into project design decisions.

Hydro One Networks Inc. shall not be liable, whether in contract, tort or any other theory of liability, to any person who uses the results of the Customer Impact Assessment under any circumstances whatsoever for any damages arising out of such use unless such liability is created under some other contractual obligation between Hydro One Networks Inc. and such person**.**

FINAL ADDENDUM - CUSTOMER IMPACT ASSESSMENT
GRAND BEND WIND FARM
100 MW WIND TURBINE GENERATION CONNECTION

1.0 INTRODUCTION

Grand Bend Wind L.P. is to develop a 100 MW wind energy generation facility. The wind farm facility, known in this document as Grand Bend Wind Farm (GBWF), will be located in the Town of Zurich. The interconnection station to Hydro One will be located in the Municipality of Huron East. GBWF is proposing to connect to Hydro One's transmission system through one new step-up transformer located near the wind farm and a new 230 kV, 30 km customer-owned underground transmission cable. This new 230 kV underground transmission cable will tap onto Hydro One's B23D circuit, approximately 2.8 km from Seaforth TS as shown in Map 1. The earliest expected in-service date of the generation facility is July 2014.

Map 1: GBWF connection to Hydro One's Network

In accordance with section 6 of the Ontario Energy Board's Transmission System Code, Hydro One Networks Inc (Hydro One) is to carry out a Customer Impact Assessment (CIA) study to assess the impact of the proposed generator connection on existing customers in the affected area.

The initial final version of this report was issued to potentially impacted customers on January 4, 2012. Subsequently Grand Bend Wind L.P. has modified several characteristics of their wind farm systems. Major changes include turbine manufacturer, collection systems, and their 30 km 230 kV underground transmission cable.

The draft addendum for this report was issued to potentially impacted customers on March 22, 2013 indicating several additional studies required to be completed by the generator proponent. Since that time those studies have been completed and the results are presented herein. This report highlights GBWF's impact to Hydro One customers. The affected customer's participation in mitigating the impacts is imperative to the connection of the proposed project.

This study does not evaluate the overall impact of the Grand Bend Wind Farm on the bulk electricity system. The impact of the new generator on the bulk electricity system is the subject of the System Impact Assessment issued by the Independent Electricity System Operator (IESO).

The study does not evaluate the impact of the Grand Bend Wind Farm on the network Protection and Control facilities. Protection and Control aspects are reviewed during the Protection Impact Assessment, which is part of the SIA. Protection and Control aspects are again reviewed, in detail, during the preparation of the Connection Cost Estimate and will be reflected in the Connection and Cost Recovery Agreement.

1.2 Proposed Connection: Grand Bend Wind Farm

1.2.1 The Wind Farm

The proposed 100 MW wind farm consists of 46 Siemens 2.3 MW Wind Turbine Generators (WTG). Seven (7) preselected turbines will be de-rated to mitigate noise requirements and thus limit the wind farm to 100 MW. Appendix A, Figure 1 shows an overview of the proposed connection arrangement.

The GBWF project consists of 3 groups of 14, 15 and 17 x 2.3 MW WTG units. Each group of wind turbines is connected via a 34.5 kV feeder and is protected by a circuit breaker before connecting to a 34.5 kV bus at the wind farm HV substation. This substation is located in the Municipality of Bluewater and will be called "Zurich WF" Customer Generating Station (CGS). At Zurich WF CGS, the power will be transformed to 230 kV via one 34.5/230 kV, 75/100/125 MVA transformer.

From Zurich WF CGS, a new 30 km, single circuit 230 kV customer-owned underground transmission cable will connect into the interconnection station adjacent to Hydro One's Right-Of-Way (ROW). The interconnection station will be called "Zurich" Customer Switching Station (CSS). Zurich CSS will contain two 230 kV circuit breakers and a motorized disconnect switch. The new 230 kV line will connect to Hydro One's existing 230 kV circuit B23D through these 230 kV breakers and the motorized disconnect switch which will be the point of demarcation between the Generator's facilities and those of Hydro One.

The wind farm's dynamic VAr compensation is provided via their Siemens 2.3 MW WTG. The WTG are designed to supply or absorb reactive power to or from the transmission grid to regulate and stabilize the voltage. In addition, it was determined in the Draft System Impact Assessment - Addendum that this project will also require static Var compensation of 34 MVAr @ 220 kV that can be provided via shunt reactor bank connected to the 230 kV underground cable and to be located at Zurich WF CGS.

1.2.2 Connection to Hydro One's 230 kV Transmission System

GBWF will connect its generated power via a new 30 km 230 kV customer-owned underground transmission line/cable to Hydro One's existing 230 kV circuit B23D, from Bruce A TS to Detweiler TS. Zurich CSS will connect directly via two 230 kV breakers and a motorized disconnect switch to Hydro One's B23D circuit. The connection point to Hydro One will be on the West side of the B22/23D ROW approximately 2.8 km south from Seaforth TS near tower # 154 of circuit B23D.

1.3 Customers in the Study Area

The primary focus of this study was on customers supplied from stations directly connected to circuit B23D and in the local electrical area. Affected customers are show in Table 1.

Table 1: Transmission Customers connected in the study area

Station	Customer
Bruce A TS	Bruce Power L.P.
Majestic CTS	Suncor Energy Products Inc. & Accoina Wind Energy Canada Inc.
Wingham TS	Hydro One Networks Distribution Westario Power Inc.
Seaforth TS	Eric Thames Powerlines Corp. Festival Hydro Inc. Hydro One Networks Distribution
Festival MTS	Festival Hydro Inc.
Stratford TS	Eric Thames Powerlines Corp. Festival Hydro Inc. Hydro One Networks Distribution

2.0 METHODOLOGY & CRITERIA

2.1 Power System Analysis

Power system analysis is an integral part of the transmission and distribution planning process. It is used by Hydro One to evaluate the capability of the existing network to deliver power and energy from generating stations to provide a reliable supply to customers. Two relevant aspects of Power System Analysis were used for this assessment, namely:

a. Load Flow Studies: An AC load flow program was used to set up a base case with GBWF.

b. Short-Circuit Studies: A Short Circuit Analysis program was used to determine the impact of GBWF on customers at their points of connection to Hydro One.

2.2 Study Assumptions

Summer 2014 conditions were assumed in this study, along with the following assumptions.

- Load Data – study area demand scaled to its 2014 peak & operating at historical power factors
- Transmission Data – all transmission system elements in-service; new Bruce x Milton double circuit line in-service; Nanticoke TS & Detweiler TS SVC's in-service
- Generation Data – all new committed embedded and transmission connected renewable generation as part of the Feed-In-Tariff (FIT) program including Samsung phase 1, 2 and 3 projects; all 8 Bruce GS units in-service; all existing Bruce area wind at 100% rated output.

Note: Load flow base cases provided by IESO

2.3 Planning Criteria

2.3.1 Voltage Limitations

To establish the adequacy of the Hydro One transmission system for the incorporation of the proposed GBWF generation facilities, the following post-fault voltage change criteria were applied. As per "IESO Transmission Assessment Criteria", Issue 5.0

http://www.ieso.ca/imoweb/pubs/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

- The loss of a single power system element should not result in a voltage change greater than 10% for pre- transformer tap-changer action (including station loads) and 10% post-transformer tap-changer action (5% for station loads) ;
- The loss of a double or 2nd power system element should not result in a voltage change greater than 10% for pre- transformer tap-changer action (including station loads) and 10% post-transformer tap-changer action (5% for station loads) ;
- Voltages below 50 kV shall be maintained in accordance with Canadian Standard Association document CAN-3-C235-83.

2.3.2 Short Circuit Limitations

Appendix 2 of the Transmission System Code (TSC) specifies the maximum symmetrical three phase and single line to ground short circuit levels. These limits are summarized in Table 2. Short circuit levels were compared to the TSC limits and also to existing breaker ratings at effected stations to ensure equipment capability.

Table 2: Transmission System Code Symmetrical Short Circuit Limits

Nominal Voltage (kV)	Max. 3 Phase Fault (kA)	Max. SLG Fault (kA)
500	80(1)	80(1)
230	63	80(1)
115	50	50
44	20(3)	19(2,3)
27.6 (4-wire)	17(3)	12(3)
27.6 (3-wire)	17(3)	0.45(3)
13.8	21(3)	10(3)

Notes:

(1) Usually limited to 63kA

(2) Usually limited to 8 kA

(3) Effective September 1, 2010, Hydro One requires a 5% margin on the acceptable TSC limits at voltage levels of <50kV to account for other sources of fault current on the distribution system such as un-modeled synchronous motors and data inaccuracies.

In order to reflect realistic operating conditions, short circuit studies are run assuming the following conditions:

- Base case assumes existing & committed generating facilities in-service.
- Pre-fault voltage of 550.00 kV at 500 kV stations
- Pre-fault voltage of 250.00 kV at 220 kV stations
- Pre-fault voltage of 127.00 kV at 115 kV stations
- Pre-fault voltage of 46.00 kV at 44 kV stations
- Pre-fault voltage of 29.00 kV at 27.6 kV stations
- Pre-fault voltage of 14.2 kV at 13.8 kV stations

2.4 Operating Conditions

Normal operating conditions are such that GBWF will solely generate onto circuit B23D. When GBWF's 230 kV transformer breaker (s) or 230 kV transmission line connected to 230 kV circuit B23D is taken out of service, GBWF will not generate onto Hydro One's systems, transmission nor distribution.

Additional operating conditions with respect to the switching of the underground cable and shunt reactor will be outlined in the Transmission Connection Agreement after completion of additional studies.

3.0 SHORT CIRCUIT RESULTS

Short-circuit studies were carried out to assess the fault contribution when the 100 MW GBWF generating facility is connected and generating onto circuit B23D.

The study results are summarized in Tables 3 and 4 below showing both symmetric and asymmetric fault currents in kA, respectively. The anticipated fault levels after the incorporation of all committed and proposed generation in the Bruce area are shown in Table 3.

Table 3: Anticipated Fault Levels Resulting from FIT3 and Samsung Phase 2 & 3 contracts

Station	Symmetrical Fault Level (kA)		Asymmetrical Fault Level (kA)	
	3-Phase	L-G	3-Phase	L-G
Bruce A TS 230 kV	44.42	55.94	59.47	**80.54**
Majestic CTS B22D 230 kV	18.90	16.44	22.76	18.58
Majestic CTS B23D 230 kV	18.46	16.33	22.15	18.42
Wingham TS 44 kV	10.75	11.20	11.19	12.82
Seaforth TS 115 kV	13.67	16.42	15.50	19.57
Seaforth TS 27.6 kV	13.92	10.79	13.97	11.71
Festival MTS 27.6 kV	15.63	4.14	17.19	5.41
Stratford TS 27.6 kV	14.34	10.68	14.56	12.19
Detweiler TS 230 kV	23.60	23.12	27.67	29.50
Detweiler TS 115 kV	24.59	28.51	28.57	35.25

*Includes existing, committed and proposed generation projects in the Bruce Transmission Area as per applications received by December 2012.

Observations made from the short-circuit study results in Table 3 above may be summarized as follows:

It can be observed from Table 3 that the anticipated fault levels at the stations shown are below the maximum symmetrical three-phase and single line-to-ground fault values set out in Appendix 2 of the TSC. In addition, with the exception of Bruce A TS 230 kV bus**, the anticipated fault levels are within Hydro One's breaker ratings.

**Note: The asymmetrical fault current at Bruce A 230 kV before and after the incorporation of the project will exceed the interrupting capability of the existing breakers. To address this issue in the long term, Hydro One has planned to replace the Bruce 230 kV breakers to improve fault current interrupting capability. Before the circuit breakers are replaced, temporary operational mitigation measures have been developed by Hydro One in collaboration with the IESO. The GBWF has no impact on this issue.

Conclusion

The short-circuit level increases at Bruce A TS, Majestic CTS, Wingham TS, Seaforth TS, Stratford TS, Festival MTS and Detweiler TS are acceptable to Hydro One and are below Hydro One's 5% TSC margin limit.

4.0 STEADY STATE VOLTAGE ANALYSIS

Steady state load flow studies were carried out to analyze the impact of the new facilities on the voltage performance of Hydro One customers in the affected area.

Local voltage impact was assessed using load flow contingency analysis. Two base cases were used to assess the voltage impact. Listed below is the description of the base case conditions, as well as, the status of GBWF and the contingencies assessed.

1. Peak Summer Loading Conditions
    a. GBWF at full output and supplying 0.9 lagging reactive power to the system
        i. A single contingency loss of GBWF generation
        ii. A single contingency loss of B23D (which includes GBWF)
        iii. A single contingency loss of GBWF when B22D is out of service pre-contingency

2. Light Loading Conditions
    a. GBWF at full output and absorbing 0.95 leading reactive power from the system
        i. A single contingency loss of GBWF generation
        ii. A single contingency loss of B22D
        iii. A single contingency loss of Seaforth TS T6 230/115 kV autotransformer.

Basic Assumptions:
- ➢ A shunt reactor rated at 34 MVAr at 220 kV to be installed at Zurich WF CGS for generator reactive power capability as per IESO System Impact Assessment requirements.
- ➢ ULTC – Under Load Tap Changer

Results are shown in Appendix B, Tables 1 – 6 and summarized below:

- Table B1: For the loss of the proposed generator the maximum voltage change is -0.74 % at Wingham TS 44 kV bus before ULTC operation and is -0.73 % at Seaforth TS 27.6 kV buses after ULTC operation.

- Table B2: For the loss of the entire 230 kV circuit B23D (between Bruce A TS and Detweiler TS which includes the proposed generator) the maximum voltage change is –9.93 % at Stratford TS 27.6 kV bus before ULTC operation and is –4.43 % at Festival Hydro MTS 27.6 kV bus after ULTC operation.

- Table B3: Given the entire 230 kV circuit B22D is out of service, for the loss of the proposed generator the maximum voltage change is –1.37 % at Wingham TS 44 kV bus before ULTC and is –1.33 % at Stratford TS 27.6 kV bus after ULTC operation.

- Table B4: For the loss of the proposed generator the maximum voltage change is 0.57 % at Seaforth TS 27.6 kV bus before ULTC operation and is 0.57 % at Seaforth TS 27.6 kV buses after ULTC operation.

- Table B5: For the loss of the entire 230 kV circuit B22D (between Bruce A TS and Detweiler TS) the maximum voltage change is –2.17 % at Seaforth TS 27.6 kV bus before ULTC operation and is –2.21 % at Seaforth TS 27.6 kV bus after ULTC operation.

- Table B6: Given the entire 230 kV circuit B22D is out of service, for the loss of the proposed generator the maximum voltage change is –2.27 % at Seaforth TS 27.6 kV bus before ULTC and is –2.33 % at Seaforth TS 27.6 kV bus after ULTC operation.

Conclusion

Steady state load flow studies confirm that the incorporation of 100 MW of wind generation between Bruce A TS and Detweiler TS will not result in a sub-standard steady state voltage profile of customers supplied from 230 kV circuits B22D/B23D and in the local electrical area. Following the worst contingency, the voltage changes are within the voltage change guideline for customer buses of less than 10% and 5% voltage drop before- and after- transformer tap-changer operation.

7.0 TRANSMITTER REQUIREMENTS

Grand Bend L.P. is required to provide the following in order to mitigate negative impacts to the Hydro One transmission system and Hydro One's transmission connected customers:

1. Grand Bend Wind L.P. is required to install an IPO (Independent Pole Operated) breaker at the point of interconnection to Hydro One, at Zurich CSS. The IPO breaker with switching control will be used for energization to avoid unacceptable transients. Only one of the two breakers at Zurich CSS, is required have such capability. Upon receiving a transfer trip signal from Hydro One, Grand Bend must open both of their interconnection breakers.

2. Grand Bend Wind L.P. is required to install breakers with 362 kV interrupters at the point of interconnection to Hydro One in order to withstand Transient Recovery Voltages (TRV) upon de-energization.

3. Due to Temporary Over-Voltage (TOV), transformer surge arrestors at the 230 kV terminals at stations connected to circuit B23D must be up-rated to a minimum of:

- minimum MCOV: 180 kV (rms)
- TOV capability: The arrester should be capable of withstanding a power frequency overvoltage of not less than 275 kV rms for 0.1 sec with no prior duty

Note that if the transformers are protected by rod-gap or silicon carbide arresters, they can withstand the TOVs, and therefore immediate replacement is not required.

   a. Hydro One surge arresters that must be up-rated before GBWF is connected to B23D are those protecting the Seaforth TS T6 autotransformer and the Stratford TS T2 transformer. Transformers at Wingham TS are currently protected by rod-gaps.

   b. Customer surge arresters that must be up-rated before GBWF is connected to B23D are those protecting the Majestic CTS transformer and Festival #1MTS transformer connected to B23D.

4. To mitigate the potential development of ferroresonance, Grand Bend is required to immediately open its breaker(s) at Zurich CSS, if the 230 kV/ 34.5 kV step-up transformer at Zurich WF CGS is not loaded, i.e. the unloaded step-up transformer and/or the shunt reactor must not "dangle" from Hydro One's transmission system.

5. Rule: Grand Bend shall not switch its 34 MVar 230 kV shunt reactor while connected to Hydro One: the sequence of energizing and de-energizing to be determined later.

6. Rule: Grand Bend shall switch into service its 34 MVar 230 kV shunt reactor prior to its connection to Hydro One. The shunt reactor must remain in-service while the generator is connected to Hydro One. If the shunt reactor is unavailable, the generator must disconnect from Hydro One via their breaker(s) at Zurich CSS.

7. Rule: Grand Bend cannot discharge their cable via Hydro One's systems (transmission nor distribution)

8. For assessment of unbalance voltages in long cables, Grand Bend to conduct EMTP/PSCAD studies for their cable installation design and submit the results to Hydro One for review before their connection date to Hydro One.

9. Grand Bend Wind L.P. is required to have Hydro One install a Power Quality Monitoring (PQM) device at the point of interconnection to Hydro One for approximately one year to track PQ performance of its facilities.

10. Grand Bend to size their transformers and circuits/cable to be able to carry the amount of reactive power (MVar) required in the Market Rules in addition to the full 100 MW of generation.

6.0 CONNECTION RELIABILITY

The incorporation of the new generator facilities will add one new 30 km 230 kV customer-owned underground transmission line/cable from the wind farm's collection substation to their interconnect with Hydro One. The additional 230 kV circuit exposure is considerable in length and may materially reduce the performance of Hydro One's B23D circuit as outlined in the Protection Impact Assessment (PIA) which was included in the IESO's SIA.

The negative impacts of the new generation facility on the local 230 kV circuit performance is expected to be mitigated by the installation of two 230 kV high voltage circuit breakers in series at the interconnection point to Hydro One. The 230 kV breakers will isolate disturbances associated with the generator transmission cable, step-up transformer and the plant's sub-transmission system. The requirement of two breakers at the point of interconnection will also prevent a Breaker Failure condition for faults on the new 30 km transmission cable from cascading onto Hydro One's 230 kV system, hence causing the entire B23D circuit from Bruce A TS to Detweiler TS to trip. One of these breakers shall have IPO capability with switching control while both breakers shall have 362 kV rated interrupters. In addition, replacement of surge arrestors that protect transformers connected directly to B23D shall be upgraded to withstand TOV induced by the new generation facility.

7.0 PRELIMINARY OUTAGE IMPACT ASSESSMENT

The work required to connect GBWF to circuit B23D will involve outages to this circuit and possibly circuit B22D and 115 kV circuit L7S. The work required to replace transformer surge arresters at Seaforth TS and Stratford TS will involve outages to at least these transformers.

These outages will be coordinated with existing transmission customers. These outages will be identified when a detailed construction schedule is established in consultation with Grand Bend during the detailed engineering and construction phases of the project development.

In addition, there is no expected outage on the transmission system associated with the construction/installation of the new wind turbine units.

It is anticipated that work required at customer stations to replace transformer surge arresters at Majestic CTS and Festival #1 MTS will also involve outages. Customers must arrange for/request these outages as per existing outage management protocols.

Periodically circuit B23D will be unavailable due to either planned or forced outages that could be either momentary or sustained. Note the primary source for GBWF's station service (SS) is to be their 34.5 kV bus which is fed off their main systems connected to circuit B23D. When circuit B23D is unavailable, GBWF will be required to use a back-up/secondary source for their station service requirements. GBWF is currently proposing to use a permanent emergency diesel generator via an Automatric Transfer Switch (ATS). Typically DC battery life is limited to 6-8 hours (or less during cold weather). Hydro One recommends that the permanent emergency generator be able to be placed in-service by a remote controller due to the remote location of the wind farm. Since outages could be of long duration, GBWF should ensure that an extended outage will not affect their internal systems and ability to reconnect to the grid once the circuit becomes available. If deemed necessary, as a possible alternative GBWF should evaluate connecting their SS to a rural supply.

8.0 CONCLUSIONS AND RECOMMENDATIONS

This Addendum: Customer Impact Assessment (CIA) presents results of short-circuit, and steady state voltage performance study analyses as well as the requirements resulting from additional switching and transient studies perform by the generator proponent and Hydro One.

In addition to the facilities required by the IESO by issue of the original SIA and its subsequent addendum and required by the original CIA and this addendum, GBWF is required to install the following facilities as part of their connection:

- Relocate the Line Arrester to the generator's side of their motorized line disconnection switch, 89-LH1 (i.e. the point of demarcation)
- Design and construct the grounding system for the Generation Facilities to meet the requirements of the Electrical Safety Code (Ontario), the Transmission System Code and the requirements set out in the connection agreements without relying on Hydro One's grounding system (including sky wire).
- Install an Independent Pole Operated (IPO) with switching control breaker at Zurich CSS
- Both breakers at Zurich CSS shall have 362 kV rated interrupters.

The following upgrades at Hydro One and customer stations are also required prior to the connection of GBWF:

- Transformer 230 kV terminal surge arrester up-rating at Majestic CTS, Seaforth TS, Festival #1 MTS and Stratford TS; for those transformers connected to circuit B23D only.

Grand Bend Wind L.P. shall be financial responsible for the all work performed by both Hydro One and its customers in order to meet their connection requirements.

All customers are required to check to ensure that the equipment and grounding system at their stations/facilities meet the expected increase in fault level.

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APPENDIX A: DIAGRAMS

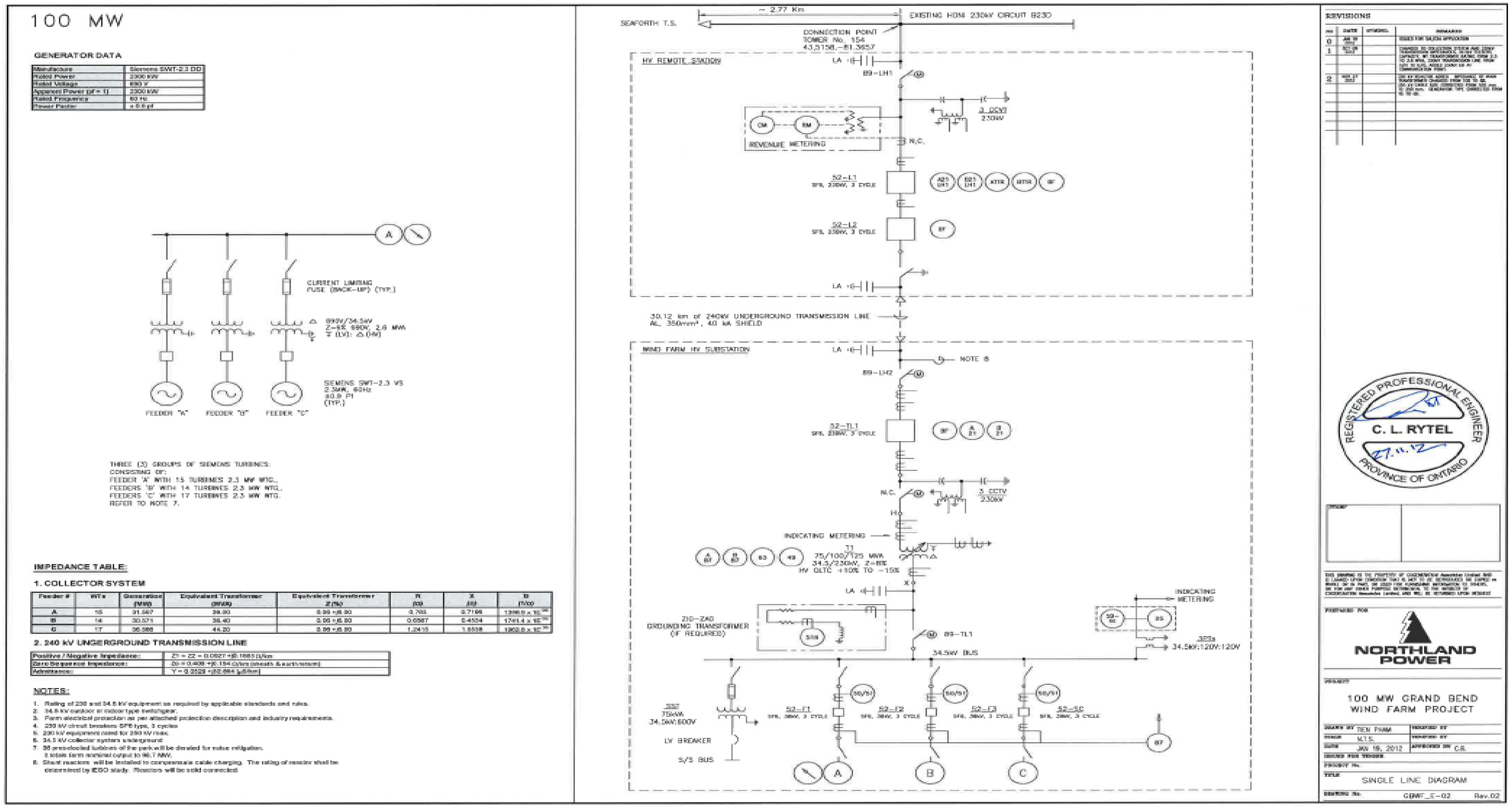

Figure 1: Grand Bend Wind Farm (drawing from generator)
Figure 1 for reference only

APPENDIX B: VOLTAGE PERFORMANCE RESULTS

Table B1: Loss of GBWF

Bus	Initial Voltage (kV)	Before ULTC (kV)	Change	After ULTC (kV)	Change
Bruce A TS 230 kV	247.35	247.15	-0.08	247.15	-0.08
Majestic CTS B22D 230 kV	246.05	245.71	-0.14	245.71	-0.14
Majestic CTS B23D 230 kV	246.58	245.97	-0.25	245.97	-0.25
Wingham TS 44 kV	46.47	46.12	-0.74	46.45	-0.04
Seaforth TS 115 kV	123.64	122.77	-0.70	122.77	-0.70
Seaforth TS 27.6 kV	29.19	28.98	-0.73	28.98	-0.73
Stratford TS 27.6 kV	29.12	28.92	-0.68	28.92	-0.69
Festival MTS 27.6 kV	29.04	28.84	-0.71	28.84	-0.72
Detweiler TS 230 kV	245.31	244.53	-0.32	244.51	-0.32
Detweiler TS 115 kV	124.60	124.20	-0.32	124.19	-0.32

Table B2: Loss of B23D

Bus	Initial Voltage (kV)	Before ULTC (kV)	Change	After ULTC (kV)	Change
Bruce A TS 230 kV	247.35	246.91	-0.18	246.95	-0.16
Majestic CTS B22D 230 kV	246.05	244.57	-0.60	244.70	-0.55
Majestic CTS B23D 230 kV		--	--	--	--
Wingham TS 44 kV	46.47	43.75	-5.84	46.27	-0.42
Seaforth TS 115 kV	123.64	120.81	-2.29	121.15	-2.01
Seaforth TS 27.6 kV	29.19	28.49	-2.39	28.95	-0.82
Stratford TS 27.6 kV	29.12	26.23	-9.93	28.29	-2.86
Festival MTS 27.6 kV	29.04	27.48	-5.38	27.76	-4.43
Detweiler TS 230 kV	245.31	244.20	-0.45	244.33	-0.40
Detweiler TS 115 kV	124.60	124.02	-0.46	124.09	-0.41

Table B3: Loss of GBWF while B22D is Out-of-Service

Bus	Initial Voltage (kV)	Before ULTC (kV)	Change	After ULTC (kV)	Change
Bruce A TS 230 kV	247.52	247.32	-0.08	247.32	-0.08
Majestic CTS B22D 230 kV	--	--	--	--	--
Majestic CTS B23D 230 kV	246.08	245.34	-0.30	245.35	-0.30
Wingham TS 44 kV	46.37	45.74	-1.37	46.45	0.18
Seaforth TS 115 kV	122.77	121.56	-0.99	121.57	-0.98
Seaforth TS 27.6 kV	28.98	28.68	-1.03	29.05	0.27
Stratford TS 27.6 kV	28.85	28.47	-1.31	28.46	-1.33
Festival MTS 27.6 kV	28.02	27.68	-1.20	27.68	-1.21
Detweiler TS 230 kV	245.18	244.33	-0.35	244.30	-0.36
Detweiler TS 115 kV	124.52	124.09	-0.35	124.07	-0.36

Table B4: Loss of GBWF

Bus	Initial Voltage (kV)	Before ULTC (kV)	Change	After ULTC (kV)	Change
Bruce A TS 230 kV	247.38	247.72	0.14	247.73	0.14
Majestic CTS B22D 230 kV	246.31	246.68	0.15	246.68	0.15
Majestic CTS B23D 230 kV	246.54	247.01	0.19	247.02	0.19
Wingham TS 44 kV	46.09	46.26	0.38	46.26	0.39
Seaforth TS 115 kV	123.60	124.29	0.55	124.29	0.56
Seaforth TS 27.6 kV	29.03	29.19	0.57	29.19	0.57
Stratford TS 27.6 kV	29.13	29.28	0.53	28.95	-0.62
Festival MTS 27.6 kV	29.11	29.27	0.54	29.03	-0.27
Detweiler TS 230 kV	245.70	246.48	0.32	246.49	0.32
Detweiler TS 115 kV	123.45	123.84	0.31	123.84	0.32

Table B5: Loss of B22D

Bus	Initial Voltage (kV)	Before ULTC (kV)	Change	After ULTC (kV)	Change
Bruce A TS 230 kV	247.38	247.97	0.24	247.90	0.21
Majestic CTS B22D 230 kV	--	--	--	--	--
Majestic CTS B23D 230 kV	246.54	246.47	-0.03	246.31	-0.10
Wingham TS 44 kV	46.09	45.16	-2.01	45.14	-2.05
Seaforth TS 115 kV	123.60	120.97	-2.13	120.93	-2.16
Seaforth TS 27.6 kV	29.03	28.40	-2.17	28.39	-2.21
Stratford TS 27.6 kV	29.13	28.82	-1.06	28.82	-1.07
Festival MTS 27.6 kV	29.11	28.77	-1.16	28.77	-1.17
Detweiler TS 230 kV	245.70	246.46	0.31	246.44	0.30
Detweiler TS 115 kV	123.45	123.79	0.28	123.78	0.27

Table B6: Loss of Seaforth TS T6 Autotransformer

Bus	Initial Voltage (kV)	Before ULTC (kV)	Change	After ULTC (kV)	Change
Bruce A TS 230 kV	247.38	247.47	0.04	247.46	0.03
Majestic CTS B22D 230 kV	246.31	246.19	-0.05	246.18	-0.05
Majestic CTS B23D 230 kV	246.54	246.92	0.15	246.92	0.15
Wingham TS 44 kV	46.09	46.14	0.13	46.14	0.12
Seaforth TS 115 kV	123.60	120.85	-2.23	120.79	-2.28
Seaforth TS 27.6 kV	29.03	28.37	-2.27	28.35	-2.33
Stratford TS 27.6 kV	29.13	29.17	0.14	29.17	0.13
Festival MTS 27.6 kV	29.11	29.15	0.13	29.14	0.12
Detweiler TS 230 kV	245.70	245.83	0.05	245.82	0.05
Detweiler TS 115 kV	123.45	123.49	0.03	123.48	0.03