Nova Scotia POWER
An Emera Company

Interconnection Feasibility Study Report
GIP-IR643-FEAS-R1

Generator Interconnection Request 643
100 MW Wind Generating Facility
Queens County, NS

2022-04-09

Control Centre Operations
Nova Scotia Power Inc.

Executive Summary

The Interconnection Customer (IC) submitted an Interconnection Request (IR#643) for Network Resource Interconnection Service (NRIS) or Energy Resource Interconnection Service (ERIS) for a proposed 100 MW wind generation facility interconnected to the NSPI transmission system, with a Commercial Operation Date of 2023-08-31. The Point of Interconnection (POI) requested by the customer is the 138kV substation 50W-Milton.

There are six transmission and five distribution Interconnection Requests currently in the Advanced Stage Transmission and Distribution Queue that must be included in the study models for IR#643. The IC has indicated that IR#643 be studied as an expansion of IR#597 which is at the System Impact Study stage in the Queue. In addition, there is one long-term firm transmission service reservation in the amount of 550 MW from New Brunswick to Nova Scotia (TSR-411). This transmission service request is expected to be in service in 2025 and system studies are currently underway to determine the associated upgrades to the Nova Scotia transmission system. These upgrades are expected to materially alter the configuration of the transmission system in Nova Scotia. As a result, the following notice has been posted to the OASIS site at https://www.nspower.ca/oasis/generation-interconnection-procedures:

> *Effective January 19th, 2021, please be advised that the completion of advanced-stage Interconnection Studies under the Standard Generator Interconnection Procedures (GIP) may be delayed pending the outcome of the Transmission Service Request (TSR) 411 System Impact Study, which is expected to identify significant changes to the NSPI transmission system. The revised expected completion date for the study is February 28, 2022. Feasibility Studies initiated prior to the completion of the TSR System Impact Study will be performed based on the current system configuration.*

This study assumes that the addition of generation from IR#643 will displace coal-fired generation in eastern Nova Scotia for both NRIS and ERIS.

The following Network Upgrades are necessary to mitigate the transmission element overload conditions:

- Use the 138kV bus 50W-B4 at 50W-Milton as the POI for IR#597 and IR#643
- Move the 99W-Bridgewater terminal of L-6006 and L-6002 from bus 99W-B61 to bus 99W-B62 with associated protection and control functions
- Uprate switches and metering on the 69kV line L-5016 at 11V, 12V, 13V and 70V to match the seasonal conductor rating.

The Network Upgrade identified for NRIS would not be necessary if IR#643 is limited to 33 MW (or a total combined output limit of 66 MW between IR#597 and IR#643) under certain operating conditions. This restriction would be in addition to any other system conditions that require curtailment of wind energy resources.

IR#643 is located approximately 5.3 km from 50W-Milton substation, and its is assumed that the 138kV spur line and circuit breaker at 50W-Milton were previously installed by IR#597 with enough capacity to support IR#597 and IR#643.

No violations of voltage criteria were found for IR#643.

Since 50W-Milton is not classified as Bulk Electric System (BES), however because IR#643 is a dispersed generation facility in excess of 75 MVA, Inclusion I4 of the NERC BES Definition would apply, and each generator would be classified as a Bulk Electric System element. There is the potential for an exclusion from BES to be granted for the high side (138kV) bus based on further analysis per the NS BES Exception Procedure.

Based on the provided rated power factor of the Vestas V150-Mk3 4.0 MW wind turbines, the provided impedances of the transformers and the typical equivalent collector circuit, the required net power factor of +0.95 to -0.95 at the Interconnection Facility 138kV bus was found to require a10 Mvar capacitor bank (5 Mvar on each of the IR#643 34.5 kV buses).

No concern regarding high short-circuit level or voltage flicker was found for this project on its own, provided that the project design meets NSPI requirements for low-voltage ride-through, reactive power range and voltage control. Harmonics must meet the Total Harmonics Distortion provisions of IEEE 519. The minimum short circuit level at the Interconnection Facility 138kV bus is 848 MVA with all lines in service, and 405 MVA with L-6025 open between the POI and 99W-Bridgewater. The calculated minimum Short Circuit Ratio at the high voltage terminals of the Interconnection transformer was found to be 3.3 with breaker 99W-625 open, below the recommended minimum of 5.0 for the Vestas V150-Mk3 4.0 MW.

The preliminary value for the unit loss factor is calculated as +0.1% at the POI at 50W-Milton 138kV. Losses associated with the IC facilities (spur line, collector circuits, transformers) are excluded from this calculation.

The preliminary non-binding cost estimate for interconnecting net 100 MW to the POI at 50W-Milton 138kV as NRIS is $1,001,000 including 10% contingency. This estimate assumes that the 3.5 km 138 kV spur line and circuit breaker at 50W-Milton was previously installed by IR#597 with enough capacity for IR#643. The Network Upgrades included in this estimate amount to $660,000 and are funded by the IC but are eligible for refund under the terms of the GIA. The remainder of the costs are fully funded by the IC.

The estimated cost for interconnection of IR#643 under ERIS is $341,000 including 10% contingency under the assumption that the 138kV spur line and circuit breaker at 50W-Milton are constructed under IR#597. Under ERIS, IR#643 would be limited to 33 MW (or a combined total of 66 MW between IR#597 and IR#642) under certain operating conditions.

The estimated time to construct the Transmission providers Interconnection Facilities is 18-24 months after receipt of funds.

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1 Introduction

The Interconnection Customer (IC) submitted an Interconnection Request for Network Resource Interconnection Service (NRIS) for a proposed 100 MW wind generation facility interconnected to the NSPI transmission system, with a Commercial Operation Date of 2023-08-31. The Point of Interconnection (POI) requested by the customer is the 138kV substation 50W-Milton. The proposed Interconnection Customer's Interconnection Facility (ICIF) is to be an extension to IR#597, a proposed 33.6 MW wind farm approximately 5.3 km from the POI, requiring a radial spur line, which is assumed to have been constructed as part of IR#597.

The IC signed a Feasibility Study Agreement to study the connection of their proposed generating facility to the NSPI transmission system dated 2021-11-17, and this report is the result of that Study Agreement. This project is listed as Interconnection Request 643 in the NSPI Interconnection Request Queue and will be referred to as IR#643 throughout this report. The study is to include Energy Resource Interconnection Service (ERIS) as well as NRIS.

Figure 1 shows the proposed geographic location of IR#643 in relation to the NSPI transmission system.

Figure 1 IR#643 Mersey Wind II Site Location

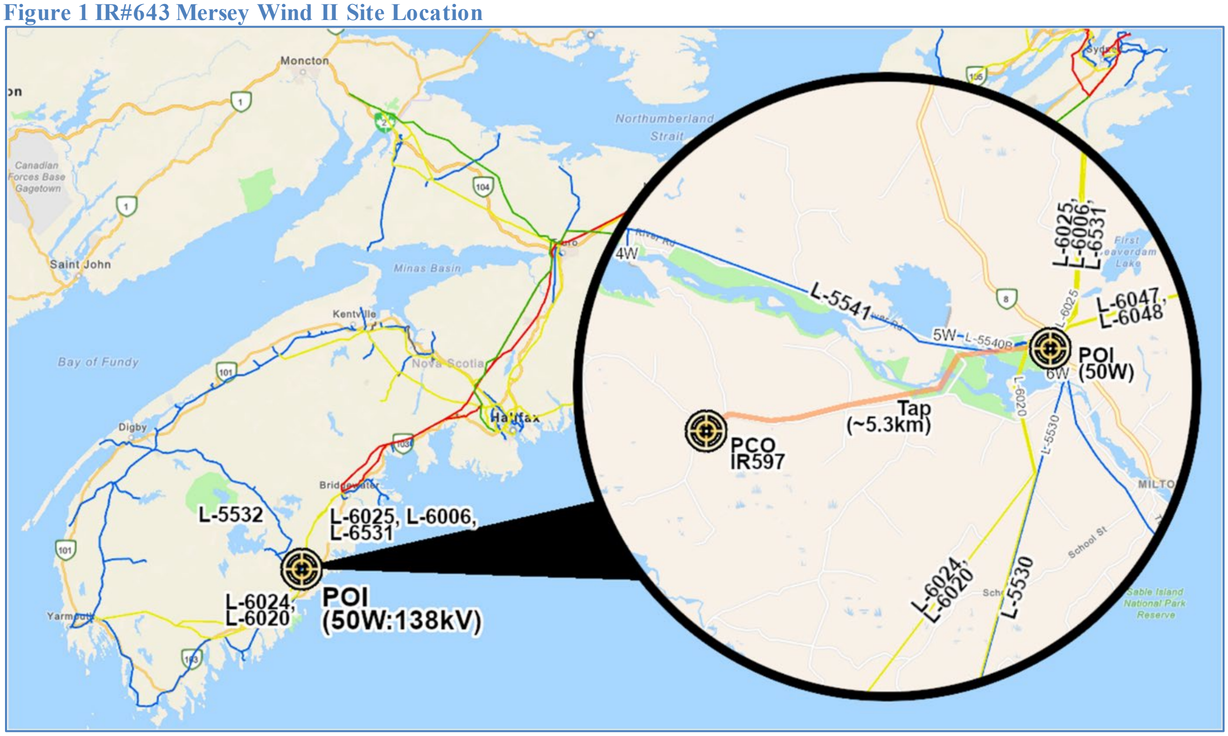


Figure 2 is a simplified one-line diagram of the transmission system configuration near the proposed POI. Figure 3 shows the circuit breaker configuration of transmission lines in the vicinity of the POI.

Figure 2 Point of Interconnection (not to scale)

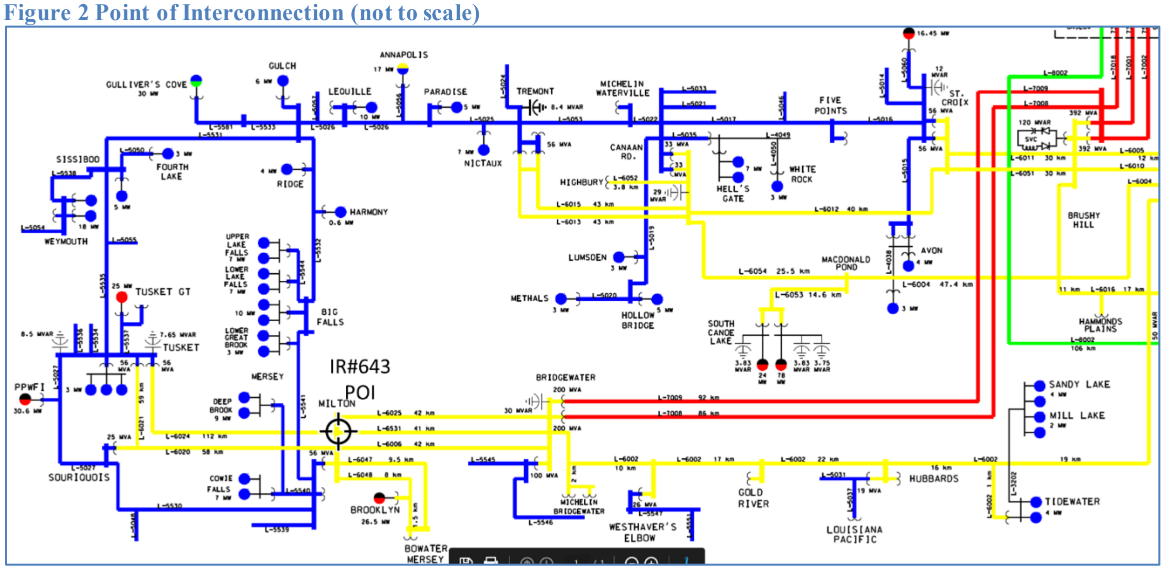
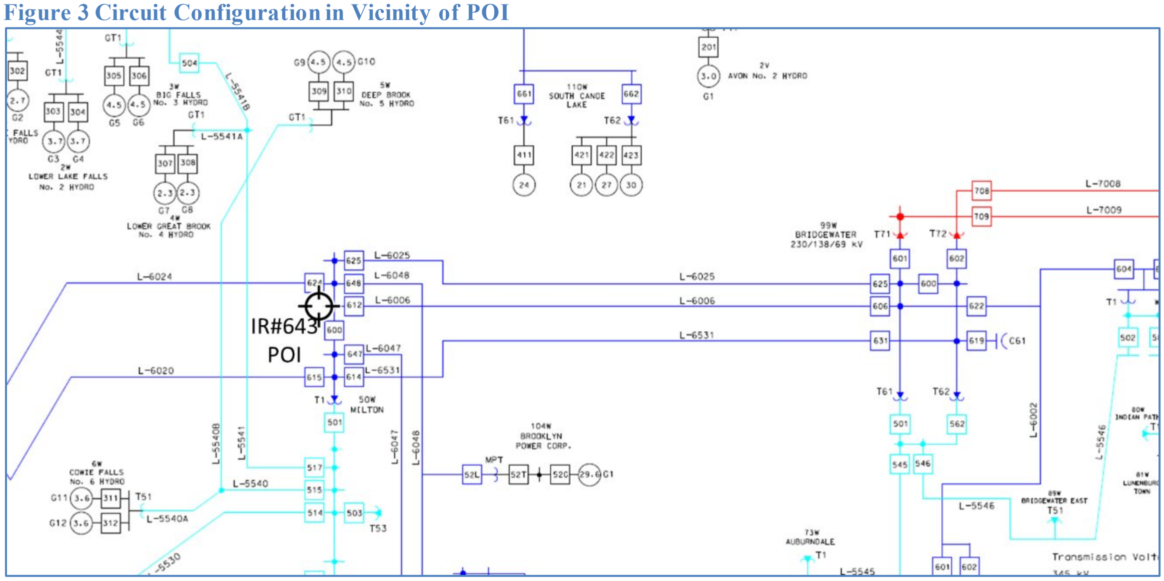


Figure 3 Circuit Configuration in Vicinity of POI



2 Scope

The objective of this Interconnection Feasibility Study (FEAS) is to provide a preliminary evaluation of system impacts from interconnecting the proposed generation facility to the NSPI transmission system at the requested location. The assessment will identify potential impacts on transmission element loading, which must remain within their thermal limits. Any potential violations of voltage criteria will be identified and addressed. If the proposed generation increases the short-circuit duty of any existing circuit breakers beyond their rated capacity, the circuit breakers must be upgraded. Single contingency criteria are applied.

The scope of the FEAS includes the modelling of the power system in normal state (with all transmission elements in service) under anticipated load and generation dispatch conditions. A power flow and short circuit analysis is performed to provide the following information:

- Preliminary identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection, and any network upgrades necessary to address the short circuit issues associated with IR#643. Expected minimum short circuit capability will also be identified for the purposes of Short Circuit Ratio analysis.

- Preliminary identification of any thermal overload or voltage limit violations resulting from the interconnection and identification of the necessary network upgrades to allow full output of the proposed facility. Thermal limits are applied to the seasonal (summer/winter) emergency ratings of transmission elements. Voltage violations occur when the post-contingency transmission bus voltage is outside the range of +/-10% of nominal voltage.

- Preliminary analysis of the ability of the proposed Interconnection Facility to meet the reactive power, power quality and cold-weather capability requirements of the NSPI *Transmission System Interconnection Requirements*[1].

- Preliminary description and high-level non-binding estimated cost and time to construct the facilities required to interconnect the generating facility to the transmission system.

- For comparative purposes, the impact of IC#643 on incremental system losses under standardized operating conditions is examined.

This FEAS is based on a power flow and short circuit analysis and does not include a complete determination of facility changes/additions required to increase the system transfer capabilities that may be required to meet the design and operating criteria established by NSPI, the Northeast Power Coordinating Council (NPCC), and the North

[1] [transmission-system-interconnection-requirements (nspower.ca)]

American Electric Reliability Corporation (NERC). These requirements will be determined by a more detailed analysis in the subsequent interconnection System Impact Study (SIS). An Interconnection Facilities Study (FAC) follows the SIS to ascertain the final cost estimate to the interconnect the generating facility.

The ERIS study identifies necessary upgrades to allow full output of the proposed Generating Facility and the maximum allowed output, at the time the study is performed, of the interconnecting Generating Facility without requiring additional Network Upgrades.

3 Assumptions

This FEAS is based on the technical information provided by the IC. The Point of Interconnection (POI) and configuration is studied as follows:

1. NRIS and ERIS per section 3.2 of the GIP.

2. Commercial Operation date 2023-08-31.

3. IR#597 is in-service prior to IR#643, and the 138kV radial transmission line between 50W-Milton and IR#597 has been built by IR#597 with sufficient capacity for both IR#597 (33.6 MW) plus IR#643 (100 MW).

4. The Interconnection Customer Interconnection Facility (ICIF) consists of 25 Wind Energy Converter System (WECS) units; Vestas V150-Mk3, 4.0 MW, 720V, Type 4 (FSCS full converter model), connected to a total of four collector circuits operating at a voltage of 34.5kV. Total plant nameplate rating is 100 MW.

5. The generation technology used must meet NSPI requirements for reactive power capability of at least 0.95 capacitive to 0.95 inductive at the HV terminals of the IC substation step up transformer. It is also required to have high-speed Automatic Voltage Regulation to maintain constant voltage at the designated voltage control point during and following system disturbances as determined in the subsequent System Impact Study. The designated voltage control point will either be the low voltage terminals of the wind farm transformer, or if the high voltage terminals are used, equipped with droop compensation controls. It is assumed that the generating units are not de-rated in their MW capability when delivering the required reactive power to the system. The IC has indicated that the Vestas V150-Mk3 WECS has a nominal power factor range from 0.91 capacitive to 0.94 reactive.

6. Preliminary data was provided by the IC for the ICIF substation, consisting of two 138kV-34.5kV 30/40/50 MVA station transformers. The substation step-up transformers were each modeled with a positive-sequence impedance of 8.5% on 30 MVA base with an X/R ratio of 20.0. The IC indicated that the ICIF station transformers have grounded wye-delta-wye winding configuration with +/-10% off-

load tap changer in 5 steps. The station transformers were modeled as a single equivalent component, impedance of 8.5% on 60 MVA base.

7. The impedance of each generator step-up transformer was given as 9.9% on 5.15 MVA with an assumed X/R ratio of 12.14. The step-up transformers were modeled as a single equivalent with an impedance of 9.9% on a base of 128.75 MVA.

8. An equivalent collector circuit model was not provided, therefore typical data was used with a positive sequence impedance of 0.003+j0.004, B=0.015 (per unit on 100 MVA).

9. The FEAS analysis is based on the assumption that IR's higher in the Generation Interconnection Queue and OATT Transmission Service Queue that have completed a System Impact Study (SIS), or that have a SIS in progress will proceed, as listed in Section 4 below. The only SIS stage project that is sufficiently progressed to include in the model is IR597.

10. It is noted that the WECS are rated at -34°C, and therefore they are suitable for delivering full power under expected winter environmental conditions.

11. Planning criteria meeting NERC Standard TPL-001-4 *Transmission System Planning Performance Requirements* and NPCC Directory 1 *Design and Operation of the Bulk Power System* as approved for use in Nova Scotia by the Utility and Review Board, are used in evaluation of the impact of any facility on the Bulk Electric System.

12. The rating of transmission lines in the vicinity of IR#643 are shown in Table 1.

Table 1 Local Transmission Element Ratings

Line	Conductor	Design Temp	Limiting Element	Summer Rating Normal/Emergency	Winter Rating Normal/Emergency
L-7008	1113 Beaumont	70°C	CT Ratio	398/438 MVA	398/438 MVA
L-7009	795 Drake	50°C	Conductor	223/245 MVA	340/374 MVA
L-6002	556.5 Dove	50°C	Cond/Switch	110/121 MVA	143/157 MVA
L-6006	795 Drake	50°C	Conductor	135/149 MVA	205/225 MVA
L-6025	1113 Beaumont	70°C	CT Ratio	200/220 MVA	200/220 MVA
L-6531	556.5 Dove	50°C	Conductor	110/121 MVA	165/181 MVA
L-5535	2/0 Quail	50°C	Conductor	23/25 MVA	34/37 MVA
L-5532	4/0 Penguin Quail	50°C	Conductor	23/25 MVA	34/37 MVA
L-6021	336.4 Linnet	50°C	Switch	72/79 MVA	72/79 MVA
L-6020	336.4 Linnet	50°C	Conductor	82/90 MVA	121/133 MVA
L-6024	795 Drake	50°C	Switch	72/79 MVA	72/79 MVA

4 Projects with Higher Queue Positions

All in-service generation is included in the FEAS, except for Lingan Unit 2, which is assumed to be retired.

As of 2022-03-23, the following projects are higher queued in the Advanced Stage Transmission Interconnection Request Queue and are committed to the study base cases:

- IR426: GIA executed
- IR516: GIA executed
- IR540: GIA executed
- IR542: GIA executed
- IR574: GIA in progress
- IR598: FAC in progress
- IR597 SIS in progress
- IR629: SIS in progress
- IR647: SIS in progress
- IR649: SIS in progress
- IR650: SIS in progress
- IR651: SIS in progress

The following project has been submitted to the Transmission Service Request (TSR) Queue:

- TSR411: SIS in progress

Preceding IR#643 are six transmission and five distribution Interconnection Requests with GIA's executed. A long-term firm point-to-point transmission service reservation in the amount of 550 MW from New Brunswick to Nova Scotia (TSR-411). This transmission service request is expected to be in service in 2025 and system studies are currently underway to determine the required upgrades to the Nova Scotia transmission system. As a result, the following notice has been posted to the OASIS site at https://www.nspower.ca/oasis/generation-interconnection-procedures:

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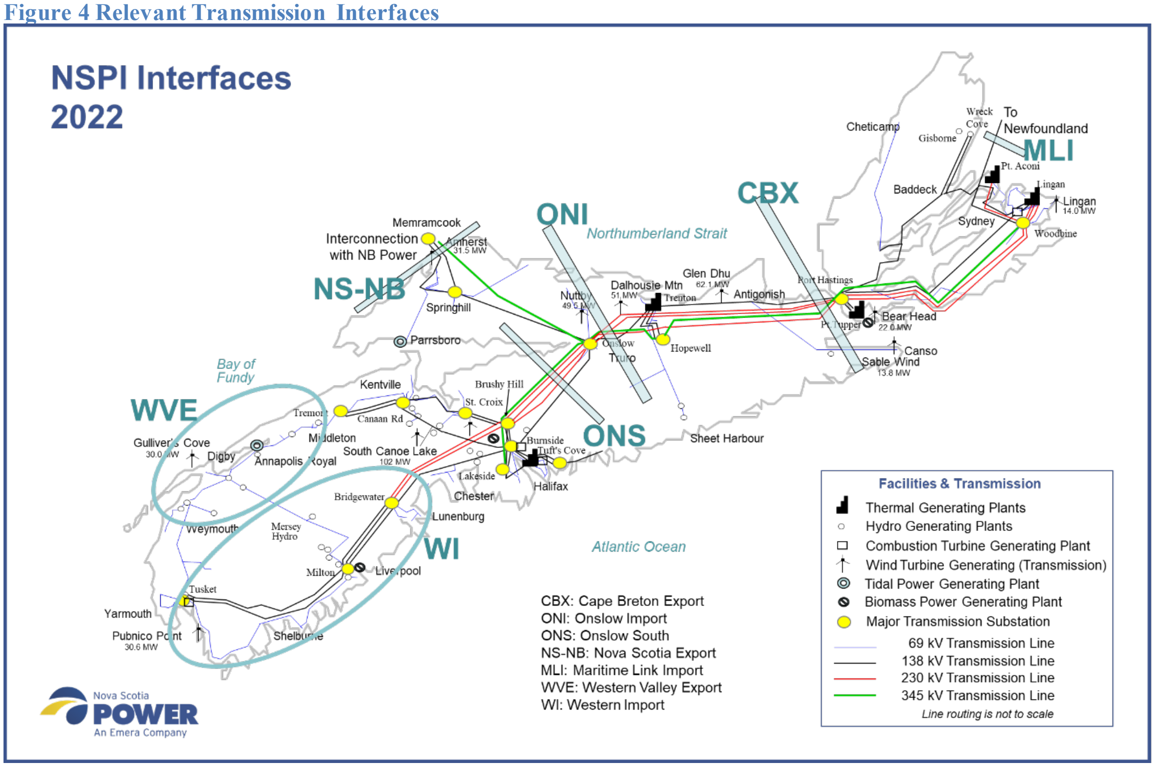
5 Load Flow Analysis

The load flow analysis was completed for generation dispatches under winter peak load conditions, summer low-hydro and spring high-hydro load conditions expected to stress transfers in western NS and Annapolis Valley.

Figure 4 shows the relevant interfaces on the NSPI transmission system.

Figure 4 Relevant Transmission Interfaces



Transmission connected wind generation facilities were typically dispatched at approximately 40%, except in the vicinity of IR#643. There is high correlation between wind plants in western NS between Digby, Yarmouth and Halifax, so it is reasonable to expect that these other wind plants would be near full output when IR#643 is at rated output.

The Western region of Nova Scotia is sensitive to the balance between local load and hydro/wind generation. Hydro plants are likely to be at rated capacity during spring run-off conditions and are less likely to be so during the drier summer and fall months. The 10W-Tusket Gas Turbine plays an important role in ten-minute operating reserve which can be called upon at any time, so transmission capacity in the vicinity of IR#643 takes this into consideration.

The cases and dispatch scenarios considered are shown in Table 3.

Table 3: Base Case Dispatch (MW)									
Case	NS-NB	LOAD	HYDRO	ONS	VE	WI	WVI	IR#643	Wind
SP01-1	335	1350	20	513	-9	96	54	0	231
SP01-2	335	1350	20	412	-9	-29	54	102	333
SP02-1	0	890	140	328	56	13	-22	0	161
SP02-2	0	890	140	228	56	-86	-22	102	263
SP03-1	330	1350	20	523	-9	40	54	0	229
SP03-2	330	1350	20	423	-9	-59	54	102	331
SP04-1	330	1350	20	391	-9	73	54	0	356
SP04-2	330	1350	20	290	-9	-27	54	102	458
W01-1	180	2200	124	850	-17	121	83	0	323
W01-2	180	2200	124	746	-17	20	83	102	425
W02-1	180	2200	124	858	7	136	60	0	485
W02-2	180	2200	124	755	7	35	60	102	585
S – Summer/Spring W - Winter Peak; LOAD – Excludes PHP									

For both NRIS and ERIS analysis, this FEAS added IR#643 and displaced an equivalent amount of coal-fired generation in Cape Breton. Single contingencies were applied at the 230kV, 138kV, and 69 kV voltage levels for the above system conditions with IR#643 interconnected to the POI at 50W-Milton 138kV. Automated analysis searched for violations of emergency thermal ratings and emergency voltage limits for each contingency. Contingencies studied are listed in Table 4. It should be noted that a number of existing contingencies unrelated to IR#643 can result in the separation of the western transmission system and possible disconnection of IR#643.

Table 4 Contingency List			
Transmission Line	**Transformer / Bus**	**Circuit Breaker Failure**	**Double Circuit Tower**
L-7008, L-7009	120H: T71, T72	120H: 715, 716, 712, 713	L-7008 + L-7009
L-6025, L-6006, L-6531	99W: B61, B62		
L-6024, L-6020, L-6021	50W: B2, B3, B4, T1		
L-5035	9W: B52 B53		
L-5025, L-5026	51V: B51, B62		

NRIS Results
There are two possible 138kV interconnection points for the IR#643 POI at 50W-Milton, bus 50W-B3 or bus 50W-B4.

The most significant contingencies resulting in thermal overload for either connection point option is the loss of bus 99W-B61 which results in overload of L-6531. This contingency opens lines L-6006 and L-6025 at the 99W-Bridgewater end, leaving IR#643 connected to 50W-Milton and flow on L-6531 at 150%[2] of its summer emergency thermal limit. This same condition would exist for contingency loss of the transformer 99W-T61.

If the POI for IR#643 is bus 50W-B3 at 50W-Milton, then loss of bus 50W-B4 at 50W-Milton would have the same effect of overloading L-6531. However, if the POI for IR#643 is 50W-B4, then IR#643 will automatically isolate for that contingency.

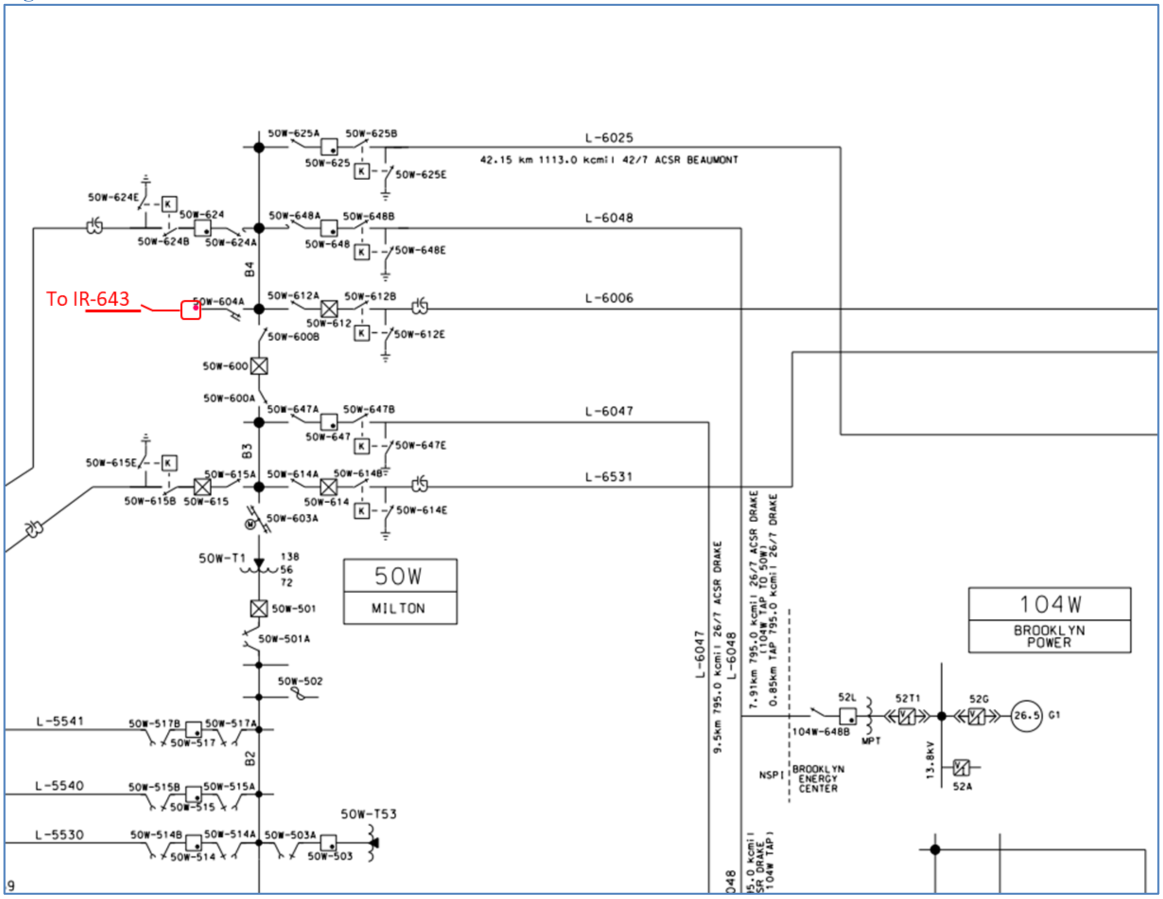
The following options were examined:

1. Increase the operating temperature of L-6531 from 50°C to 70°C at an estimated cost of $6,150,000 plus 10% contingency.
2. Move L-6006 from bus 99W-B61 to 99W-B62 at 99W-Bridgewater. This would involve protection and control changes at 99W-Bridgewater but would not require a node swap at 50W-Milton if the POI is 50W-B4. It is estimated to cost $100,000 plus 10% contingency.
3. Move the 99W-Bridgewater end of L-6006 from 99W-B61 to 99W-B62, and re-route the 50W-Milton end of L-6006 to an open breaker node on 50W-B3 opposite 50W-647. This would require moving a circuit breaker at 50W-Milton and is estimated to cost $1,100,000 plus 10% contingency. It is unlikely that there would be room for the POI for IR#643 on bus 50W-B3 in this case, requiring it to be bus 50W-B4.
4. Swap line terminations for L-6006 and L-6531 at each end. This will leave L-6006 connected between 50W-B3 and 99W-B62. However, L-6006 would be loaded to 105% of its summer emergency rating for the same contingency that caused L-6531 to be loaded to 133% of its summer emergency rating, and would require a thermal upgrade from 50°C to 55°C and the cost would likely be in the same order of magnitude as Option 1.
5. Tie lines L-6006 and L-6531 together to operate as a single circuit between buses 50W-B3 and 99W-B62. This would utilize the switchgear of L-6531 which is rated at least 200 MVA. The entry conductors would need to be changed to Drake or Beaumont. This is estimated to cost $1,000,000 plus 10% contingency, but it would reduce flexibility in future operation and maintenance.

[2] Based on the requirement to provide 25 MW of Tusket Gas Turbine summer operating reserve at any time. Without Tusket Gas Turbine, the circuit loading would exceed the seasonal emergency limit by 33% (133% of emergency rating).

The recommended option is (2) which will require the POI for IR#643 to be the node 50W-604 shown in Figure 5.

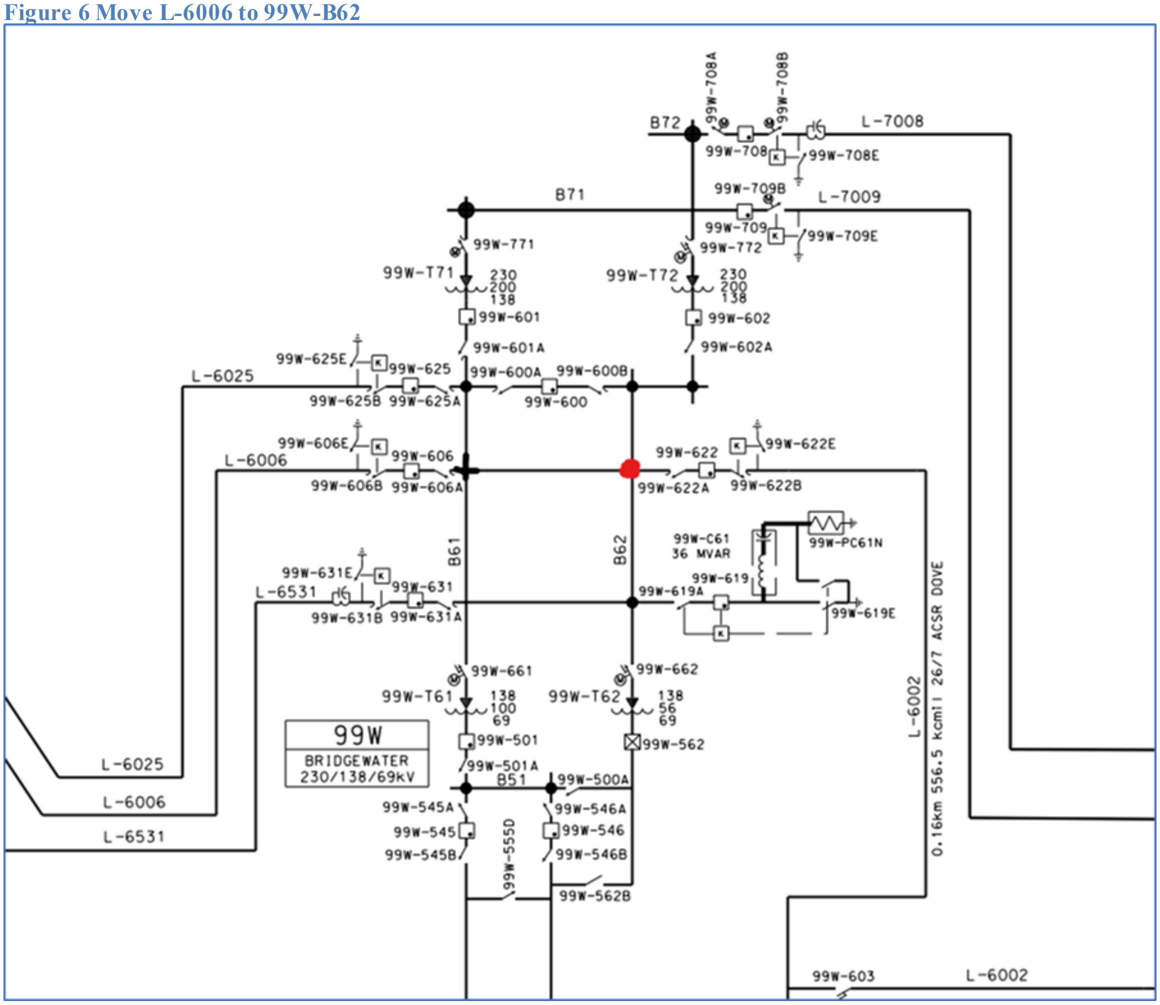
Figure 5 POI on bus 50W-B4



The change at to the termination of L-6006 and L-6002 at 99W-Bridgewater is shown in Figure 6. The POI for IR#643 would need to be 50W-B4, assumed to be the existing node 50W-604A as shown in Figure 7. This leaves the next largest contingency which would be loss of 138kV bus 50W-B3. This contingency results in the loss of the 138kV-69kV transformer 50W-T1, L-6020, L-6031, and L-6047. This would leave IR#643 connected to the grid through L-6025, L-6006 and L-6024. However, transmission line L-5026 in the Annapolis Valley would be loaded at 110% - 115% of it’s summer and winter rating. L-5026 is limited by switchgear and metering at 11V, 12V, 13V, and 70V. Uprating these elements would increase the summer line rating by at least 92%.

No contingencies resulted in a violation of voltage limit criteria, under the assumption that the existing contingencies which result in western separation are excluded.

Figure 6 Move L-6006 to 99W-B62



ERIS Results

To avoid the thermal limit violations encountered in the NRIS analysis, IR#643 could operate at up to 33 MW (or a total of 66 MW between IR#597 and IR#643) without the need for transmission limit upgrades. This limitation would be expected to apply for up to 60 hours per year, during spring run-off. This limitation would be in addition to any other system condition that would require curtailment of wind energy resources.

6 Short-Circuit Duty / Short Circuit Ratio

The maximum (design) expected short-circuit level is 5,000 MVA (21 kA) on 138kV systems and 10,000 MVA (25 kA) on 230kV systems. The fault current characteristic for the Vestas V150-Mk3 – 4.0 MW fully converted units is given as 1.2 times rated current, or X'd = 0.8 per unit.

Short circuit analysis was performed using PSS®E for a classical fault study, 3LG and flat voltage profile at 1.0 p.u. V. The short-circuit levels in the area before and after this development are provided below in Table 2.

Table 2: Short-Circuit Levels. IR#643 Three-phase MVA (1)

Location	Without IR#643	With IR#643
All transmission facilities in service		
Interconnection Facility (138kV)	1404	1510
50W-Milton (138kV)	1588	1693
Minimum Conditions (PA1, LG1, ML In-Service)		
Interconnection Facility (138kV), all lines in-service	799	905
Interconnection Facility (138kV), L-6025 open	610	716
Interconnection Facility (138kV), L-7009 open	637	743

(1) Classical fault study, flat voltage profile

The interrupting capability of the 138kV circuit breakers is at least 3500 MVA at 50W-Milton. As such, the interrupting ratings at these substations will not be exceeded by this development on its own.

Vestas documentation has indicated that the minimum Short Circuit Ratio (SCR) of the Vestas V150-Mk3-4.0 MW WECS is 5. Based on the calculated short circuit levels, a POI at 50W-Milton 138kV, and a 105 MW installation consisting of 25 units each 4.468 MVA on its own (not including IR#597), the minimum SCR would be 7.6 at the HV terminals of the IR#643 substation with all lines in service. This falls to 5.8 with L-6025 open, and 6.1 if L-7009 is open. However, minimum SCR should be based on IR#643 operating in tandem with IR#597 for a total of 133 MW. On that basis the minimum SCR is 4.6, below the Vestas recommended minimum value.

7 Voltage Flicker and Harmonics

Flicker coefficient information was not provided for the Vestas V150-Mk3 – 4.0 MW WECS; however, it is known that Type 4 wind turbines typically have a flicker coefficient of 2.0 - 2.4 at angle of 85°, which is about half that of Type 3 machines. Type 4 wind turbines are not expected to result in appreciable voltage flicker at minimum generation conditions. Voltage flicker will be further examined when data for the 4.0 MW Vestas V150-Mk3 machine is made available for the SIS.

The generator is expected to meet IEEE Standard 519-2014 limiting voltage Total Harmonic Distortion (all frequencies) to a maximum of 1.5%, with no individual harmonic exceeding 1.5% on 138kV.

8 Reactive Power and Voltage Control

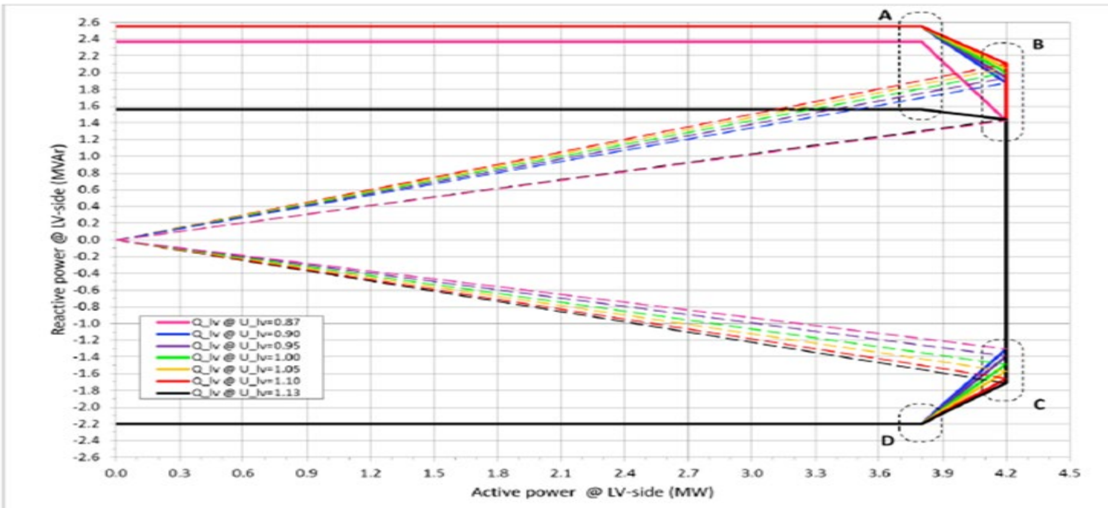
In accordance with the *Transmission System Interconnection Requirements* Section 7.6.2, IR#643 must be capable of delivering reactive power at a net power factor of at least +/- 0.95 of rated capacity to the high side of the plant interconnection transformer. Reactive power can be provided by the asynchronous generator or by continually acting auxiliary devices such as STATCOM, DSTATCOM or synchronous condenser, supplied by the Interconnection Customer. Rated reactive power shall be available through the full range of real power output of the Generating Facility, from zero to full power. Based on the plant rating of 100 MW, this translates into a reactive capability requirement of 33 Mvar leading and lagging.

The information provided by the IC indicates that the Vestas V150-Mk3 – 4.0 MW WECS have a rated power factor of 0.914 lagging and 0.949 leading at a terminal voltage of 1.0 p.u. This translates into a gross reactive power range of -37 Mvar to +48 Mvar. Figure 7 shows how reactive capability varies with voltage and real power output. It is noted that this unit is capable of reactive power control down to zero MW.

Figure 7: WECS Reactive Capability

10.7 Operational Envelope – Reactive Power Capability in 4.2 MW Power Optimized Mode (PO1)

The reactive power capability for the 4.2 MW Power Optimized Mode (PO1) is as illustrated in Figure 10-5:



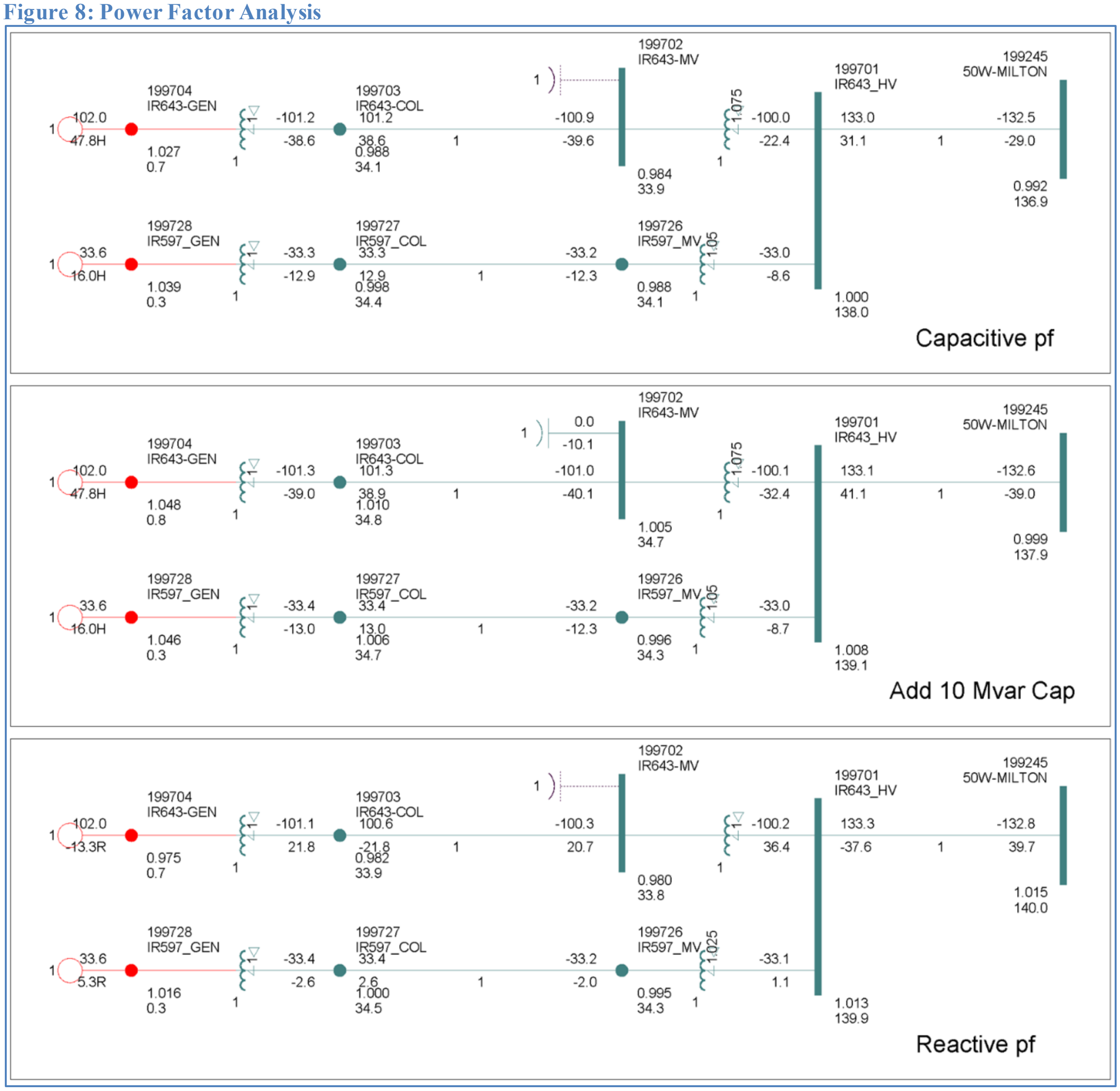
	Coordinates								Power factor	
Point:	A		B		C		D		B (Capacitive)	C (Inductive)
Coordinate:	x (P)	y (Q)	x (P)	y (Q)	x (P)	y (Q)	x (P)	y (Q)		
Reactive power [kVAr] @ LV side @ U_lv = 0.87 p.u. voltage	3.800	2.370	4.200	1.425	4.200	-1.304	3.800	-2.200	0.947	0.955
Reactive power [kVAr] @ LV side @ U_lv = 0.90 p.u. voltage	3.800	2.550	4.200	1.877	4.200	-1.304	3.800	-2.200	0.913	0.955
Reactive power [kVAr] @ LV side @ U_lv = 0.95 p.u. voltage	3.800	2.550	4.200	1.938	4.200	-1.392	3.800	-2.200	0.908	0.949
Reactive power [kVAr] @ LV side @ U_lv = 1.00 p.u. voltage	3.800	2.550	4.200	1.998	4.200	-1.490	3.800	-2.200	0.903	0.942
Reactive power [kVAr] @ LV side @ U_lv = 1.05 p.u. voltage	3.800	2.550	4.200	2.052	4.200	-1.570	3.800	-2.200	0.898	0.937
Reactive power [kVAr] @ LV side @ U_lv = 1.10 p.u. voltage	3.800	2.550	4.200	2.105	4.200	-1.660	3.800	-2.200	0.894	0.930
Reactive power [kVAr] @ LV side @ U_lv = 1.13 p.u. voltage	3.800	1.560	4.200	1.439	4.200	-1.712	3.800	-2.200	0.946	0.926

Figure 10-5: Reactive power capability for 4.2 MW Power Optimized Mode (PO1).

Analysis shown in Figure 8 demonstrates that IR#643 may not be able to meet this requirement without additional reactive support. The model shows that with 25 WECS units operating at a total 100 MW and 47.8 Mvar at terminal voltage of 1.027 p.u., the net delivered power to the high side of the ICIF transformer is 100.0 MW and 22.4 Mvar, or a power factor of 0.976. To meet the requirement of 0.95, a capacitor bank rated at 10 Mvar installed on the low voltage side of the ICIF transformer is proposed, or 5 Mvar on each of the 34.5 kV buses.

This configuration would be able to meet the leading power factor requirement while WECS are operating at 100 MW and -17 Mvar at a terminal voltage of 0.99 p.u.

Figure 8: Power Factor Analysis



A centralized controller will be required which continuously adjusts individual generator reactive power output within the plant capability limits and regulates the voltage at the 34.5 kV bus voltage. The voltage controls must be responsive to voltage deviations at the terminals of the Interconnection Facility substation; be equipped with a voltage set-point control; and also have the ability to slowly adjust the set-point over several (5-10) minutes to maintain reactive power within the individual generators capabilities. The details of the specific control features, control strategy and settings will be reviewed and addressed in the SIS, as will the dynamic performance of the generator and its excitation. Line drop compensation, voltage droop, control of separate switched capacitor banks must be provided.

The NSPI System Operator must have manual and remote control of the voltage set-point and the reactive set-point of this facility to coordinate reactive power dispatch requirements.

This facility must also have low voltage ride-through capability as per Appendix G of the Standard Generator Interconnection and Operating Agreement (GIA). The SIS will state specific options, controls and additional facilities that are required to achieve this.

Settings for the ICIF on-load tap-changer must be coordinated with plant voltage controller for long-term reactive power and voltage management at the POI.

9 System Security / Bulk Power Analysis

Presently the 138kV buses at the 50W-Milton substation are not part of the Nova Scotia Bulk Power System (BPS) and will be further evaluated in the SIS phase. However, since IR#643 has dispersed generation totalling more than 75 MVA, Inclusion I4 of the NERC BES Definition would apply, and each generator at IR#597 and IR#643 would be classified as a BES element. The 34.5 kV buses, 138kV – 69kV transformers, and the 138kV bus would also be considered BES. There is the potential for an exclusion from BES to be granted for the high side (138kV) bus based on further analysis per the NS BES Exception Procedure. This analysis will be initiated as part of the System Impact Study (SIS) and exclusion from BES will only be granted upon subsequent approval by the Nova Scotia Utility and Review Board.

10 Loss Factor

Loss factor is calculated by running the winter peak load flow case with and without the new facility in service while keeping 91H-Tufts Cove as the Nova Scotia Area Interchange bus. This methodology reflects the load centre in and around Metro.

Without IR#643 in service, losses in the winter peak case total 84.2 MW. With IR#643 in service at the POI at 50W-Milton displacing generation at 91H, and not including losses associated with the IR#643 Generation Facilities or TPIF Interconnection Facilities, system losses total 86.3 MW, an increase of 0.1 MW. The model shows power delivered to the POI is 100 MW, therefore the loss factor is calculated as 0.1/100 = +0.1%.

11 Expected Facilities Required for Interconnection

The following facility changes will be required to connect IR#643 to the NSPI transmission system at a POI at 50W-Milton 138kV:

11.1 NRIS Requirements:

a. Required Network Upgrades

- Move the drop-leads on L-6006 and L-6002 from 99W-B61 to 99W-B62 and make the necessary changes to protection at 99W-Bridgewater
- Uprate switchgear and metering on L-6026 at 11V, 12V, 13V and 70V to meet or exceed the winter thermal rating of the conductor.

b. Required Transmission Provider's Interconnection Facilities (TPIF):

- It is assumed that all TPIF to connect IR#643 to the POI at 50W-Milton 138kV bus 50W-B4 (spur line, circuit breaker, protection and communications) have been installed by IR#597.
- A separate RTU with tele-protection upgrades and programming is assumed to be required for IR#643.

c. Required Interconnection Customer's Interconnection Facilities (ICIF)

- Facilities to provide 0.95 leading and lagging power factor when delivering rated output at the HV terminals of the IC Substation Step Up Transformer when the voltage at that point is operating between 95% and 105% of nominal. This FEAS analysis suggests that a 5 Mvar capacitor bank on each of the 34.5kV buses (10 Mvar total) would provide this capability.
- Centralized controls. These will provide centralized voltage set-point controls and are known as Farm Control Units (FCU). The FCU will control the 34.5 kV bus voltage and the reactive output of the machines. Responsive (fast-acting) controls are required. The controls will also include a curtailment scheme which will limit or reduce total output from the facility, upon receipt of a telemetered signal from NSPI's SCADA system.
- NSPI will have control and monitoring of reactive output of this facility, via the centralized controller. This will permit the NSPI Operator to raise or lower the voltage set-point remotely.
- Low voltage ride-through capability per Section 7.4.1 of the Nova Scotia Power Transmission System Interconnection Requirements.
- Real-time monitoring (including an RTU) of the interconnection facilities. Local wind speed and direction, MW and Mvar, as well as bus voltages are required.

- Facilities for NSPI to execute high speed rejection of generation (transfer trip) if determined in SIS. The plant may be incorporated into RAS run-back schemes.
- Synthesized inertial response (fast frequency response) controls within the WECS.
- Automatic Generation Control to assist with tie-line regulation.

11.2 ERIS Requirements:

The TPIF and ICIF requirements for ERIS are the same as NRIS, but if the Network Upgrade facilities associated with NRIS are not completed, IR#643 shall be limited to 33 MW (or a combined total of 66 MW between IR#597 and IR#643) during certain system operating conditions.

12 NSPI Interconnection Facilities and Network Upgrades Cost Estimate

Estimates for NSPI Interconnections Facilities and Network Upgrades for interconnecting net 100 MW wind energy at the 138kV POI at on L-6025 are included in Table 5 (NRIS) and Table 6 (ERIS).

Table 5 Cost Estimate NRIS @ POI 50W-B4 Milton		
Item	**Network Upgrades**	**Estimate**
1	Move termination of L-6006 and L-6002 at 99W-Bridgewater from bus 99W-B61 to 99W-B62	$100,000
2	Uprate L-5026 to meet conductor rating	$500,000
	Sub-total for Network Upgrades	$600,000
Item	**TPIF Upgrades**	**Estimate**
1	5.3 km 138kV spur line from POI to ICIF excluding right-of-way, with138kV breaker at 50W	installed by IR#597
2	NSPI P&C relaying equipment	$100,000
3	NSPI supplied RTU	$60,000
4	Tele-protection and SCADA communications	$150,000
	Sub-total for TPIF Upgrades	$310,000
	Total Upgrades	**Estimate**
	Network Upgrades + TPIF Upgrades	$910,000
	Contingency (10%)	$91,000
	Total (Incl. 10% contingency and Excl. HST)	$1,001,000

Table 6 Cost Estimate ERIS @ POI 50W-Milton 138kV Bus B4		
Item	**Network Upgrades**	**Estimate**
	None	$0
Item	**TPIF Upgrades**	**Estimate**
1	5.3 km 138kV spur line from POI to ICIF excluding right-of-way, with138kV breaker at 50W	installed by IR#597
3	NSPI P&C relaying equipment	$100,000
4	NSPI supplied RTU	$60,000
5	Tele-protection and SCADA communications	$150,000
	Sub-total for TPIF Upgrades	$310,000
	Total Upgrades	**Estimate**
	Network Upgrades + TPIF Upgrades	$310,000
	Contingency (10%)	$31,000
	Total (Incl. 10% contingency and Excl. HST)	$341,000

The preliminary non-binding cost estimate for interconnecting net 100 MW at the POI at 50W-Milton 138kV bus 50W-B4 under NRIS is $1,001,000 including a contingency of 10%. Of this amount, $660,000 is for Network Upgrades, which are funded by the IC, but are eligible for refund under the terms of the GIA. The remainder of the costs are fully funded by the IC.

The preliminary non-binding cost estimate for interconnecting 100 MW at the POI at L-6025 under ERIS is $341,000 including a contingency of 10%. There are no Network Upgrades, therefore all the costs are fully funded by the IC. Under ERIS, IR#643 may be limited to 33 MW (or a total of 66 MW between IR#597 and IR#643) under certain operating conditions.

These cost estimates assume that the interconnection facilities associated with IR#597 are in-service and are suitably designed for the incorporation of IR#643. These estimates do not include potential additional costs to address any stability issues that may be identified at the SIS stage based on dynamic analysis.

The estimated time to construct the Transmission providers Interconnection Facilities is 18-24 months after receipt of funds.

13 Issues to be addressed in SIS

The following provides a preliminary scope of work for the subsequent SIS for IR#643. The SIS will include a more comprehensive assessment of the technical issues and requirements to interconnect generation as requested. It will include contingency analysis, system stability, ride through, and operation following a contingency (N-1 operation). The SIS must determine the facilities required to operate this facility at full capacity, withstand any contingencies (as defined by the criteria appropriate to the location) and identify any restrictions that must be placed on the system following a first contingency loss. The SIS will confirm the options and ancillary equipment that the customer must install to control flicker, voltage, frequency response, active power and ensure that the facility has the required ride-through capability. The SIS will be conducted in accordance with the GIP with the assumption that all appropriate higher-queued projects proceed, and the facilities associated with those projects are installed.

The following outline provides the minimum scope that must be complete in order to assess the impacts. It is recognized the actual scope may deviate, to achieve the primary objectives.

The assessment will consider but not be limited to the following.

i. Facilities that the customer must install to meet the requirements of the GIP and the NSPI *Transmission System Interconnection Requirements*.

ii. The minimum transmission additions/upgrades that are necessary to permit operation of this Generating Facility, under all dispatch conditions, catering to the first contingencies listed.

iii. Guidelines and restrictions applicable to first contingency operation (curtailments etc.).

iv. Under-frequency load shedding impacts.

To complete this assessment the following first contingencies, as a minimum, will be assessed:

- L-8001
- L-8002
- L-7008
- L-7009
- Simultaneous loss of L-7008 + L-7009
- Buses at 50W and 99W
- Transformer 99W-T61
- Loss of largest generation source in NS
- Loss of Maritime Link

To complete this assessment the dynamics of the following first contingencies, as a minimum, will be assessed:

- 3 phase fault L-8001 with high NS import from NB (islanding)
- 3 phase fault L-8002 at 67N-Onslow
- Simultaneous SLG on L-7008 & L-7009 double circuit tower at 120H-Brushy Hill
- 3 phase fault on transformer 99W-T61

Any changes to RAS schemes required for operation of this generating facility, in addition to existing generation and facilities that can proceed before this project, will be determined by the SIS as well as any required additional transmission facilities. The determination will be based on NERC[3] and NPCC[4] criteria as well as NSPI guidelines and good utility practice. The SIS will also determine the contingencies for which this facility must be curtailed.

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[3] NPCC criteria are set forth in its Reliability Reference Directory #1 *Design and Operation of the Bulk Power System*
[4] NERC transmission criteria are set forth in *NERC Reliability Standard TPL-001-4*