Interconnection Feasibility Study Report

GIP-314-FEAS-R2

System Interconnection Request #314

49.6 MW Wind Generating Facility

Pictou County (91N-Dalhousie Mountain Substation)

2012-01-27
Control Centre Operations
Nova Scotia Power Inc.

Executive Summary

The Interconnection Customer (IC) submitted an Interconnection Request (IR#314) for Energy Resource Interconnection Service (ERIS) to NSPI for a proposed 49.6 MW wind generation facility interconnected to the NSPI transmission system. The Point of Interconnection (POI) requested by the customer is at the 230kV substation 91N-Dalhousie Mountain.

Feasibility Studies for ERIS require the determination of the necessary upgrades to allow the full output of IR#314 and identify the maximum allowed output, at the time this Feasibility Study is performed, of the Generating Facility without requiring additional Network Upgrades.

Several contingencies result in overload of line L-7019, which has a summer rating of 233 MVA and a winter rating of 307 MVA. For IR#314 to operate at the proposed capacity of 49.6 MW, it is recommended that 28.8 km of this 29.6 km line be thermally uprated or re-built.

Under ERIS, the Generation Facility would be limited to 32 MW using the existing capacity of the Transmission System, on an “as available” basis.

No concern regarding short-circuit level was found for this project on its own. It is not expected that IR#314 will violate NSPI’s flicker requirements. The project must meet NSPI requirements for low-voltage ride-through, reactive power range and voltage control. The data provided indicates that individual machines have a rated power factor of 0.90 (assuming that the 0.90 pf option is selected), and based on the supplied transformer and assumed collector circuit data, supplementary reactive support may be needed in the form of capacitor banks at the low voltage terminals of the Interconnection Transformer. Harmonics must meet the Total Harmonics Distortion provisions of IEEE 519.

The preliminary unit loss factor is calculated to be 5.8% (system losses increased by net 2.9 MW when IR #314 is operated at 49.6 MW).

The preliminary non-binding estimated cost of facilities required to interconnect IR#314 to 91N-Dalhousie Mountain Substation under the terms of ERIS permitting full output at 49.6 MW is $3,531,000 including a contingency of 10%. Of this, $3,256,000 is considered to be Network Upgrades. This estimate is based on the assumption that it is feasible to thermally uprate the line, which would be determined by a detailed line survey. If thermal uprating is not feasible, then L-7019 would need to be re-built and the total project cost estimate rises to $15,500,000. The project interconnection costs will be further refined in the System Impact Study and the Facilities Study.

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1 Introduction

The Interconnection Customer submitted an Interconnection Request (IR) for Energy Resource Interconnection Service (ERIS) to NSPI for a proposed 49.6 MW wind generation facility interconnected to the NSPI transmission system, with an in-service date of 2014-12-31. The Point of Interconnection (POI) requested by the customer is the 230kV substation 91N-Dalhousie Mountain.

The Interconnection Customer (IC) signed a Feasibility Study Agreement to study the connection of their proposed generating facility to the NSPI transmission system dated 2011-09-15, and this report is the result of that Study Agreement. This project is listed as Interconnection Request #314 in the NSPI Interconnection Request Queue, and will be referred to as IR#314 throughout this report.

2 Scope

This Interconnection Feasibility Study (FEAS) consists of a power flow and short circuit analysis. Based on this scope, the FEAS report shall provide the following information:

1. Preliminary identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;
2. Preliminary identification of any thermal overload or voltage limits violations resulting from the interconnection;
3. Preliminary description and high level non-binding estimated cost of facilities required to interconnect the Generating Facility to the Transmission System, and to address the identified short circuit and power flow issues.

The Scope of this FEAS includes modeling the power system in normal state (with all transmission elements in service) under anticipated load and generation dispatch conditions.

In accordance with Section 3.2.1.2 of Revised Generation Interconnection Procedures (RGIP), the FEAS for ERIS consists of short circuit/fault duty, steady state (thermal and voltage) analyses. The short circuit/fault duty analysis would identify direct Interconnection Facilities required and the Network Upgrades necessary to address short circuit issues associated with the Interconnection Facilities. The steady state studies would identify necessary upgrades to allow full output of the proposed Generating Facility and would also identify the maximum allowed output, at the time the study is performed, of the interconnecting Generating Facility without requiring additional Network Upgrades.

A more detailed analysis of the technical implications of this development will be included in the subsequent System Impact Study (SIS) report. The SIS includes system stability analysis, power flow analysis such as single contingencies (including contingencies with more than one common element), off-nominal frequency operation, off-nominal voltage operation, low voltage ride through, harmonic current distortion, harmonic voltage distortion, system protection, special protection systems (SPS), automatic generation control (AGC) and islanded operation. The impacts on neighbouring power systems and the requirements set by reliability authorities such as Northeast Power Coordinating Council (NPCC), North American Electric Reliability Corporation (NERC), and NSPI will be addressed at that time and will include an assessment of the status of the Interconnection Facility as a Bulk Power System element. The SIS may identify and provide a non-binding estimate of any additional interconnection facilities and/or network upgrades that were not identified in this FEAS.

An Interconnection Facilities Study follows the SIS in order to ascertain the final cost estimate to interconnect the generating facility.

3 Assumptions

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

1. Energy Resource Interconnection Service type per Section 3.2.1 of the RGIP.
2. 49.6 MW wind with 31 units of GE 1.6 SLE Wind Turbines.
3. The generation technology used must meet NSPI requirement for reactive power capability of 0.95 capacitive to 0.95 inductive at the HV terminals of the IC Substation Step Up transformer. The generator is specified for 49.6 MW at a rated power factor of 0.90 for both lagging and leading. The data sheet indicates that a power factor of 0.90 is optional, and is assumed to be selected for this study. It is also required to have high-speed Automatic Voltage Regulation to maintain constant voltage at the generator terminals during and following system disturbances as determined in the subsequent System Impact Study.
4. The Interconnection Customer indicated that the generation interconnection point is at the NSPI substation 91N-Dalhousie Mountain, on the same breaker node as the existing generation facility. No transmission lines (230kV) or circuit breakers are proposed.
5. Preliminary data was provided by the Interconnection Customer for the generator step-up and IC substation step-up transformers. Modeling was conducted with a 230kV-34.5kV 33/44/55 MVA Interconnection Facility transformer with a positive sequence impedance of 8.33% on a base rating of 33 MVA (an X/R ratio of 20 was assumed). The proposed winding configuration is grounded-wye grounded-wye transformer with a buried delta tertiary winding and has 4 taps rated +/- 2.5% plus neutral position (5 in total).
6. The generator step-up transformers are indicated with a delta-grounded wye configuration, ratio of 34.5kV-0.69kV, and an impedance of 6% on 1.8 MVA.
7. 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 SIS, or that have a SIS in progress will proceed, as listed in Section 4 below.

4 Projects with Higher Queue Positions

All in-service generation is included in the FEAS.

As of 2011-10-26 the following projects are higher queued in the Interconnection Request Queue and OATT Transmission Service Queue, and have the status indicated.

Interconnection Requests -Included in FEAS

- IR #8 GIA Executed
- IR #45 GIA Executed
- IR #56 GIA Executed
- IR #151 GIA Executed
- IR #219 GIA Executed
- IR#227 GIA in Progress
- IR#225 GIA in Progress
- IR#234 FAC in Progress

Interconnection Requests –Not Included in FEAS

- IR #131 SIS Milestones Met
- IR #360 SIS in progress
- IR #362 SIS in progress

OATT Transmission Service Queue– Included in FEAS

- TSR-100 Final Draft Complete.

Interconnection Requests not included in FEAS

The following IRs either have SIS Agreements complete (but have not yet met the RGIP SIS progression milestones), or have Feasibility Study agreements complete. As such, they are not included in this FEAS.

IR #67	IR #68	IR #86	IR #115	IR #117	IR #126
IR #128	IR #131	IR #149	IR #163	IR #213	IR #222
IR #235	IR #238	IR #241	IR #242	IR #273	IR #291
IR #356	IR #361	IR #364	IR #365	IR #366	

OATT Transmission Service Queue– **Not** Included in FEAS

- TSR-400 SIS in progress

If any of the higher-queued projects included in this FEAS are subsequently withdrawn from the Queue, the results of this SIS may require updating or a re-study may be necessary. The re-study cost incurred as a result of the withdrawal of the higher-queued project shall be the responsibility of the Interconnection Customer that withdraws the higher queued project.

While TSR-100 is higher queued, it has an in-service date of 2016, whereas IR#314 has an in-service date of late 2014. Therefore the FEAS for this IR will be performed twice – for 2014 without TSR-100 in service and again for 2016 onwards with TSR-100 in-service, along with any related system changes.

An additional Transmission Service Request, TSR-400 is higher queued than IR#314 and a SIS is in progress. However, the results of this SIS are not sufficiently defined to be included in the FEAS for IR#314.

5 Objective

The objective of this FEAS is to provide a preliminary evaluation of the feasibility and the high-level non-binding cost estimate of interconnecting the 49.6 MW generating facility to the NSPI transmission system at the designated location. The assessment will identify potential impacts on the loading of transmission elements, which must remain within their thermal limits. Any potential violations of voltage criteria will be identified and addressed. If the proposed new generation increases the short-circuit duty of any circuit breakers beyond their rated capacity, the circuit breakers must be upgraded. Single contingency criteria[1] are applied for the ERIS assessments.

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 system transfer capabilities that may be required to the Bulk Power System to meet the design and operating criteria established by NPCC and NERC or required to maintain system stability. These requirements will be determined by the subsequent interconnection SIS (SIS).

[1] The Single Contingency Criteria is defined by NPCC in its A-7 Document, and may involve more than one transmission element.

6 Short-Circuit Duty

The maximum (design) expected short-circuit level is 10,000 MVA on 230kV and 5000 MVA on 138kV systems. The short-circuit levels in the area before and after this development (including TSR-100) are provided below in Table 6-1.

Table 6-1: Short-Circuit Levels. Three-phase MVA (1)

Location	IR #314 in service	IR #314 not in service
All transmission facilities in service		
Interconnection Facility (POI)	2460	2384
67N-Onslow 230kV	4538	4533
3C-Port Hastings 230kV	3060	3052
Minimum Conditions		
Interconnection Facility (POI)	1676	1600

(1) Classical fault study, flat voltage profile

In determining the maximum short-circuit levels with this generating facility in service the generators have been modeled as conventional machines with reactance comparable to induction machines regardless of the type of generators proposed, which provides a worst case scenario. The SIS will refine the fault level based on the actual machine characteristics.

The maximum short-circuit level at the POI with the upgrades associated with IR-100 is 2384 MVA. After installing IR #314 the increase will bring the short-circuit level to 2460 MVA at the POI. Similarly, under summer light load conditions with certain generation units offline the minimum short-circuit level will be approximately 1600 MVA at the POI. This translates into maximum equivalent system impedance at the POI of 0.0625 per unit on 100 MVA base.

The interrupting capability of the 230kV circuit breakers at 91N-Dalhousie Mountain, 67N-Onslow and 3C-Port Hastings are at least 10,000 MVA, which will not be exceeded by this development on its own.

7 Voltage Flicker and Harmonics

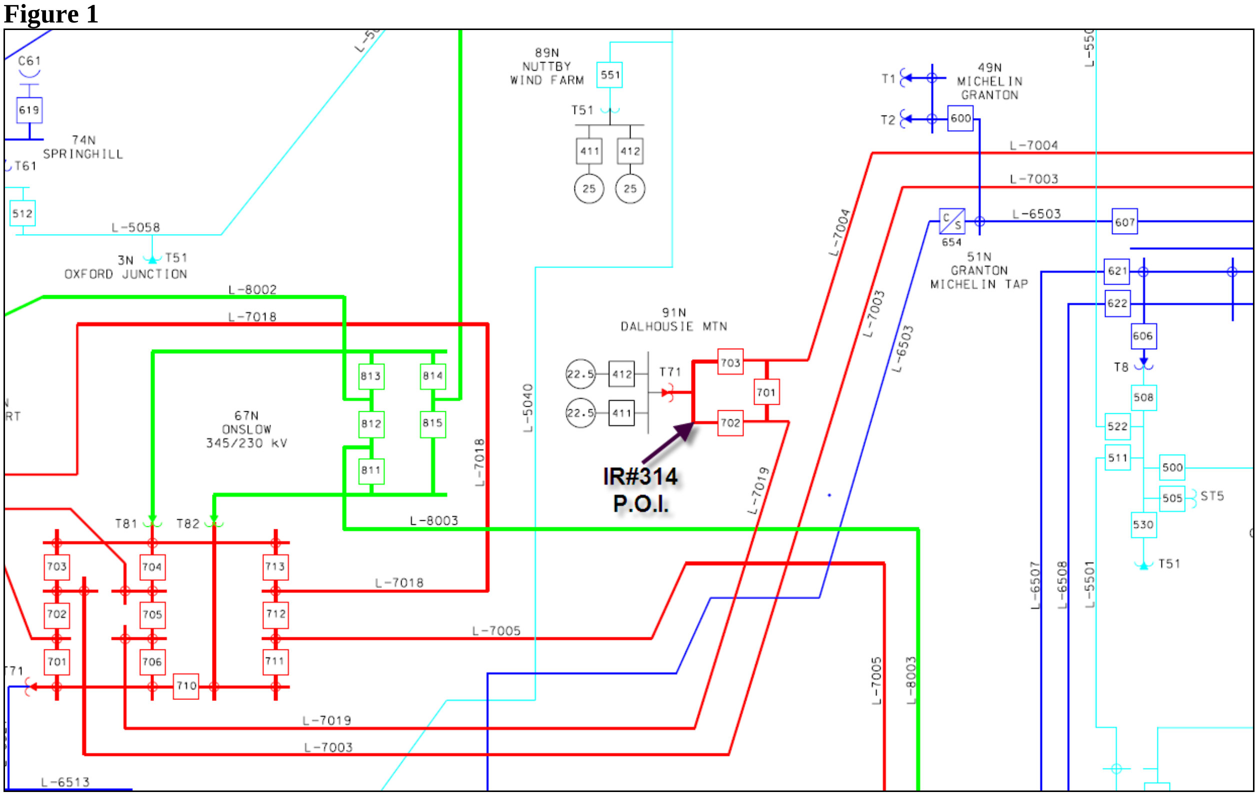
The flicker coefficient for the GE 1.6 SLE machine is assumed to be the same as the GE 1.5 SLE units. The calculated voltage flicker at the POI using IEC Standard 61400-21 and flicker coefficient $c_i\ (\Psi_k,\ v_a)$ of 4.7 is 0.06 under minimum fault level conditions. These are both below NSPI's required limit of 0.35 for P_{st}. Therefore voltage flicker should not be a concern for this project.

The Interconnection Facility is expected to meet IEEE Standard 519 limiting Total Harmonic Distortion (all frequencies) to a maximum of 5%, with no individual harmonic exceeding 1%.

8 Thermal Limits

This Generating Facility is proposed to interconnect at the NSPI 230kV substation 91N-Dalhousie Mountain as shown in Figure 1. An existing 51 MW wind energy conversion facility is interconnected at the same substation. 91N-Dalhousie Mountain substation is connected on the east to 3C-Port Hastings substation via L-7004, which is constructed of a combination of 556.5 kcm Dove ACSR conductor (36.4 km) plus 795 kcm Drake ACSR (94.6 km). To the west, 91N-Dalhousie Mountain substation is connected to 67N-Onslow via L-7019, which is constructed of 28.8 km of 556.5 kcm Dove conductor plus 0.83 km of 795 kcm Drake ACSR conductor. L-7004 is rated at 233/307 MVA summer/winter based on the 50ºC design temperature of the Dove conductor. L-7019 is also rated at 233/307 MVA summer/winter.

Figure 1



Load flow analysis demonstrated that there was no significant impact on thermal limits for winter conditions, primarily due to the higher thermal rating of transmission elements in winter, and local load (at peak) kept transmission flows below limits.

For summer and light load conditions, the results were highly dependent on the generation that IR#314 displaces. The present transfer limit for the Onslow Import Interface (ONI) is 1025 MW due to stability for loss of 345kV transmission between 101S-Woodbine, 79N-Hopewell, and 67N-Onlow. Therefore the addition of 49.6 MW at the POI, under the conditions of ERIS must displace existing generation in Cape Breton. The Cape Breton Export (CBX) limit with Interconnection Requests ahead of IR#314 in the GIP is 826 MW for Summer 2015 (i.e. before TSR-100 or TSR-400 are in service). Introduction of 49.6 MW of generation at the POI reduces generation in Cape Breton to such that CBX would be 776 MW. Because IR#314 is interconnected on one of the three 230kV circuits between CBX and ONI, it shifts the balance of flow on the circuits such that the line section L-7019 (91H-Dalhousie Mountain Substation to 67N-Onslow) overloads for certain contingencies.

Loss of the double circuit towers (DCT) that carry L-8004 and L-7005 across the Strait of Canso is the most significant contingency, overloading L-7019 by 17%, even with the SPS that rejects 310 MW net generation at Lingan when the contingency is detected. The next most significant contingency under those conditions is loss of L-7005 or L-7003 (for which no SPS currently exists) resulting in L-7019 overloading by 13% and 11% respectively. The overloads due to various contingencies, before and after the addition of IR#314 are listed in Table 8-1.

Table 8-1: Thermal Limit Analysis

Contingency	Element	Prior to IR#314 Load % of Rating	With IR#314 Load % of Rating
L-7014	L-7019	95%	107%
88S-720	L-7019	96%	107%
101S-706	L-7019	95%	106%
101S-701	L-7019	95	106%
L-7003	L-7019	98%	**111%**
L-7005	L-7019	100%	**113%**
3C-712	L-7019	93%	107%
3C-713	L-7019	97%	110%
3C-720	L-7019	98%	**111%**
67N-703	L-7019	99%	**111%**
67N-711	L-7019	100%	**113%**
1N-601	L-6513	110%	110%
1N-619	L-6513	107%	106%
DCT – L8004+L7005	L-7019	107%	**117%**
	L-6511	109%	102%

NSPI accepts a 10% overload if it is possible for the System Operator to take action to reduce the overload. Therefore only those issues in boldface type in Table 8-1 raise concern. It should also be noted that it is assumed that the contingency loss of the double-circuit tower with L-7003 and L-7004 is covered by SPS Group 3 which trips one Lingan unit. This SPS is normally only used if a 345kV line is out of service but it serves to increase CBX if armed.

Solutions to the overload were investigated. If circuits across the Strait of Canso were swapped such that L-8004 shared a tower with L-6515 instead of L-7005 then the worst contingency identified above would be eliminated. However that would not solve the five other contingencies which result in overload of L-7019. It is therefore recommended that L-7019 be uprated to a summer rating of at least 285 MVA (715A). A survey would be required to determine if it is feasible to raise the maximum operating temperature of the Dove conductor of L-7019 from 60ºC to 80 ºC. It is estimated that this thermal uprating (28.8 km) would cost $2.96M to permit IR#314 to operate at 49.6 MW. This would be considered a Network Upgrade under the GIP. If it is not feasible to raise the operating temperature of the conductor, the line would be re-built at a cost of $13.9M. Because the existing L-7019 was originally designed for 138kV operation, the thermal upgrade option is based on the unitized cost of uprating 138kV structures, whereas the rebuild option is based on the use of standard 230kV line design.

ERIS requires that an estimate of the maximum output of the generation facility without the need for transmission upgrades be provided. As such, if the plant size is reduced from 49.6 MW to 32 MW, network upgrades would not be required.

It is important to note, however, that operation of IR#314 at either load level (49.6 MW with upgrade of L-7019 or 32 MW without network upgrades) is dependent on generation at Lingan being available for SPS rejection in the amount of net 310 MW. In addition, summer conductor rating in the planning horizon is based on an assumed ambient temperature of 25ºC. If ambient temperature is higher than 25ºC in real-time operations, then transmission lines are de-rated and curtailment of transfers may be necessary.

Transmission system changes in NS have been recommended by TSR-100, to occur in 2016. These system changes will not impact IR#314 or change the recommended system upgrades.

The impact of TSR-400 on IR#314 will be determined in the SIS.

9 Voltage Limits

This project, like all new generating facilities must be capable of providing both lagging and leading power factor of 0.95, measured at the HV terminals of the IC Substation Step Up Transformer, at all production levels up to the full rated load of 49.6 MW.

Data provided by the IC indicates that IR#314 may not be able to meet this requirement without additional reactive support. Based on the assumed (optional) rated power factor of 0.90 for the GE 1.6 SLE generators and the assumed impedances of the collector circuits and transformers, capacitor banks in the range of 3-4 Mvar installed at the 34.5kV bus of the Interconnection Facility substation may be needed to meet the requirements. This will be further investigated in the SIS.

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.

The NSPI System Operator must have manual and remote control of the voltage 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 to the Standard Generator Interconnection and Operating Agreement (GIA). The SIS will state specific options, controls and additional facilities that are required to achieve this.

10 System Security / Stability Limits (Transfer Capability)

There are a number of Special Protection Systems (SPS) and protective systems employed by NSPI to permit high transfer levels across the Nova Scotia Bulk Power System. The Type I SPS designated #119 trips either one or two thermal units at Lingan for faults on the 345kV system between 101S-Woodbine and 67N-Onslow (lines L-8004, L-8003, and bus faults or breaker failures at 79N-Hopewell and 67N-Onslow). Thermal analysis conducted in Section 8 above examined the impact of the addition of IR#314 on the steady-state post-contingency conditions assuming that this SPS has rejected the required level of generation; however the SPS is primarily required for system stability, to prevent cascading tripping of parallel transmission on the corridor between Cape Breton and Onslow. The limits of the two interfaces designated as Interconnection Reliability Operating Limits (CBX and ONI) cannot be exceeded as required by NERC Standards TOP-004 and TOP-007; therefore the limits must be honoured. Increasing the thermal capacity of lines may not increase the stability limit of interfaces, so a key objective of the SIS will be the confirmation of ONI and CBX interface limits to permit the addition of flow from IR#314.

The SIS will determine if any facility changes are required to permit the proposed higher transmission loadings while maintaining compliance with NERC/NPCC reliability standards and in keeping with good utility practice. Any new SPS (or significant change to an existing SPS) must be approved by NPCC.

11 Expected Facilities Required for Interconnection

The following facility changes are required to interconnect IR #314 to the to the 230 kV bus at 91N- Dalhousie Mountain Substation:

Additions/Changes to POI at 91N-Dalhousie Mountain Substation:

1. Switches to isolate the new facility on the existing bus 91N-B71.
2. Control and communications channels between the Generating Facility and NSPI SCADA
3. Protection setting modifications.

Network Upgrades to Increase Transmission Capacity:

1. Thermal uprating of L-7019 230kV line, or
2. Re-build L-7019.

Requirements for the Generating Facility

1. Facilities to provide 0.95 leading and lagging power factor when delivering rated output (49.6 MW) 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. Preliminary analysis indicates that 3-4 Mvar of capacitors may be required at the low voltage terminals of the Interconnection Facility transformer to meet this requirement.
2. Centralized controls known as Farm Control Units (FCU). These will provide centralized voltage set-point controls. The FCU will control the voltage at the 34.5kV bus at the Generating Facility and the reactive output of the machines. 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. The controller will also limit the load ramp rate of the facility to within limits set by NSPI and/or telemetered from NSPI's SCADA system.
3. NSPI to have control and monitoring of voltage control and reactive output of this facility, via the centralized controller. This will permit the NSPI Operator to raise or lower the voltage set-point remotely.
4. Low voltage ride-through capability as per Appendix G to the Standard Generator Interconnection and Operating Agreement (GIA).
5. Real-time monitoring (including a Remote Terminal Unit) of the interconnection facilities.
6. Facilities for NSPI to execute high speed rejection of generation (transfer trip) if determined in SIS.
7. The Interconnection Facility is expected to meet IEEE Standard 519 limiting Total Harmonic Distortion (all frequencies) to a maximum of 5%, with no individual harmonic exceeding 1%.

12 NSPI Interconnection Facilities and Network Upgrades Cost Estimate

Estimates for NSPI Interconnections Facilities and Network Upgrades for interconnecting 49.6 MW wind energy conversion facility onto the 230 kV transmission system are included in Table 12-1.

Table 12-1: Cost Estimates identified from FEAS scope

	Determined Cost Items	Estimate
NSPI Interconnection Facilities		
i	Protection, control upgrades	$200,000
ii	230kV Switch at 91N	$50,000
Network Upgrades		
iii	Thermal uprating of L-7019 from 60ºC to 80°C (see Note 1)	$2,960,000
Totals		
iv	Subtotal	$3,210,000
v	Contingency (10%)	$321,000
vi	Total of Determined Cost Items (see Note 1)	$3,531,000
	To be Determined Costs	
vii	System additions to address potential stability limits	TBD (SIS)

Note 1: This estimate assumes that, based on a field survey, it is feasible to thermally uprate L-7019 otherwise the line would be re-built at an estimated cost of $13.9M.

The preliminary non-binding cost estimate for interconnecting IR#314 at 91N-Dalhousie Mountain Substation would be in the range of $3,531,000 - $15,500,000. The Interconnection Customer is also required to fund the Item (iii) costs, and would be eligible for repayment of amounts paid in accordance with the terms of the GIA (Section 11.4.1) for those elements determined in the GIA to be Network Upgrades

13 Issues to be addressed in SIS

The following provides a preliminary scope of work for the subsequent SIS for IR#314. 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 and 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 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 will 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. The facility additions/changes required to increase NSPI east to west transfers under system normal conditions (all transmission in) over the range of NSPI loads and with interruptible loads on or off. Some of the interfaces that may be constrained and should be included in the assessment are as follows.

- Cape Breton Export
- Onslow Import
- Onslow South
- Metro reactive reserve requirements
- NS – NB export/import

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.

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. Impact on System Losses.

v. Under-frequency load shedding impacts.

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

- L-8001/L-3025
- L-3006 – with and without New Brunswick Power SPS operation
- Memramcook 345/138 kV transformer
- L-8003
- L-8004
- L-7003
- L-7005
- L-7014
- L-8002 & L-8003 (common circuit breaker)
- L-8003 & L-8004 (common circuit breaker)

- L-8001 & 67N-T81 (common circuit breaker)
- L-8002 & 67N-T81 (common circuit breaker)
- L-8004 & L-7005 (common circuit tower)
- L-7003 & L-7004 (common circuit tower)
- 2C-B61 or 2C-B62 bus sections
- 1N-B61 bus

To complete this assessment the dynamics of the following first contingencies, as a minimum, will be assessed. All faults are considered permanent, i.e. automatic reclosing fails to restore the circuit.

- 3 phase fault L-8001/3025 at 67N-Onslow, NS Import SPS operation (islanding), and NS Export Power Monitor SPS operating.
- 3 phase fault L-8003 at 67N-Onslow and 79N-Hopewell
- 3 phase fault L-8002 at 67N-Onslow
- 3 phase fault L-8004 at 101S-Woodbine
- 3 phase fault L-8004 at 79N-Hopewell
- 3 phase fault L-7005 at 3C-Port Hastings
- Single Phase to Ground fault (SLG) on separate phases of L-8004 and L-7005 at the Strait of Canso.
- SLG on L-8003 at 67N-Onslow with breaker failure, drops L-8003 and L-8002
- SLG on L-8004 at 101S-Woodbine with 101S-801 breaker failure.
- 3 phase fault at 79N-Hopewell bus, drops L-8003, L-8004, bus.
- 3 phase fault 2C-B62, drops L-6516, L-6515, L-6517

Any changes to SPS 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[2] and NPCC[3] criteria as well as NSPI guidelines and good utility practice. Any new SPS, or any significant change to an existing SPS, must be approved by NPCC.
The SIS will also determine the contingencies for which this facility must be curtailed.

The SIS will calculate the unit loss factor, which is a measure of the percentage of the net output of IR #314 which is lost through the transmission system while displacing generation in the load centre. Preliminary value is calculated to be 5.8% (system losses increased by net 2.9 MW when IR #314 is operated at 49.6 MW).

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[2] NPCC criteria are set forth in its Reliability Reference Directory #1 *Design and Operation of the Bulk Power System*
[3] NERC transmission criteria are set forth in *NERC Reliability Standards TPL-001, TPL-002, TPL-003*