Interconnection Feasibility Study Report
GIP-IR634-FEAS-R1

Generator Interconnection Request 634
72 MW Solar Generating Facility
Antigonish County, NS

2022-04-08

Control Centre Operations
Nova Scotia Power Inc.

Executive Summary

The Interconnection Customer (IC) submitted a Network Resource Interconnection Service (NRIS) Interconnection Request for a proposed 72 MW solar generation facility interconnected to the NSPI transmission system, with a Commercial Operation Date of 2023-07-01. The Point of Interconnection (POI) requested by the customer is the 69kV substation 57C-Salmon River Lake, approximately 14.5 km from the IC substation.

There are five transmission and three distribution Interconnection Requests in the Advanced Stage Transmission and Distribution Queue that must be included in the study models for IR#634. In addition, there is a long-term firm Transmission Service Reservation (TSR) that must be accounted for: 550 MW from New Brunswick to Nova Scotia (TSR-411). The TSR is expected to be in service in 2025 and a system study is 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 was 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#634 will displace coal-fired generation in eastern Nova Scotia for NRIS.

57C-Salmon River Lake presently is not categorized NPCC Bulk Power System (BPS) or NERC Bulk Electric System (BES). The interconnection of IR#634 will require one 69 kV circuit breaker and associated equipment at 57C. IR#634 is not categorized NERC BES as the voltage class at the POI is below 100 kV. Complete NPCC BPS testing will be performed in the System Impact Study (SIS) to determine if it is categorized BPS.

The assessment of the POI on 57C's 69 kV bus indicated that several thermal loading and voltage violations would occur due to IR#634, notably on the following elements: L-5524, L-6511, 4C-T2 and the 4C 69 kV bus. The thermal overloads on L-5524 & 4C-T2 and the low voltage in the area would occur under system normal conditions, therefore the transformation capacity upgrade at 4C and L-5524 line rebuild are required. As an alternative to uprating the affected transmission line L-6511, arming/limit values reductions are proposed for existing Remedial Action Schemes (RAS) to alleviate most of these overloads.

Data provided by the IC indicates that IR#634 will be utilizing the Delta M250HV solar inverters. Based on the typical impedances of the transformers, IC provided collector circuit length and typical collector circuit impedances, IR#634 would not be able to meet the net power factor of +0.95 to -0.95 at the Interconnection Facility 69 kV bus. The adequacy of reactive power supply will be further investigated in the System Impact Study as specific details of the collector circuits become available. It is noted that the proposed Delta M250HV models do not meet the requirement to produce full Mvar capability down to zero MW output.

IR#634 was not found to adversely impact the short-circuit capabilities of existing circuit breakers. It is assumed that the project design meets NSPI requirements for low-voltage ride-through and voltage control. Harmonics must meet the Total Harmonics Distortion provisions of IEEE 519. The minimum short circuit level at the Interconnection Facility 69 kV bus is 87 MVA with all lines in service and results in a very low short-circuit ratio (SCR) of 1.2. In minimal generation conditions with L-6515 open at 4C-Lochaber Road, the short circuit level falls to 80 MVA, with a 1.1 SCR. The impact of the low SCR will be further examined when detailed data for the machine is made available for the SIS.

The preliminary value for the unit loss factor is calculated as +18.2% at the POI on 57C 69 kV bus, net of any losses on the IC facilities up to the POI.

The preliminary non-binding cost estimate for interconnecting 72 MW to the POI on 57C 69 kV bus is $16,208,500. This includes the cost of:

- Transformer capacity upgrade.
- L-5524 rebuild.
- A new breaker and associated equipment at 57C.
- A 14.5 km spur line from the POI to the Interconnection Customer's Interconnection Facility.

The cost estimate includes a contingency of 10%, and this estimate will be further refined in the System Impact Study and the Facility Study. In this estimate, $7,175,000 (plus 10% contingency) of the amount represents Network Upgrade costs which are funded by the IC, but which are eligible for refund under the terms of the GIP. The remainder of the costs are fully funded by the IC.

If transmission upgrades, instead of modification to the existing RAS, are found to be necessary to address these thermal overloads, the total cost of Network Upgrades would increase by an estimated $5,475,000 for the uprate of L-6511. These cost estimates do not include any contingency. Network upgrades are funded by the IC and are eligible for refund under the terms of the GIP.

The estimated time to construct the Transmission Providers Interconnection Facilities is 18-24 months, and the Network Upgrades are estimated to be completed 24-36 months after receipt of funds and cleared right of way from the customer.

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1 Introduction

The Interconnection Customer (IC) submitted a Network Resource Interconnection Service (NRIS) Interconnection Request for a proposed 72 MW solar generation facility interconnected to the NSPI transmission system, with a Commercial Operation Date of 2023-07-01. The Point of Interconnection (POI) requested by the customer is the 69kV substation 57C-Salmon River Lake, approximately 14.5 km from the IC substation.

The IC signed a Feasibility Study Agreement to study the connection of their proposed generating facility to the NSPI transmission system dated 2021-10-05, and this report is the result of that Study Agreement. This project is listed as Interconnection Request 634 in the NSPI Interconnection Request Queue and will be referred to as IR#634 throughout this report.

Figure 1 shows the proposed geographic location of IR#634 in relation to the NSPI transmission system.

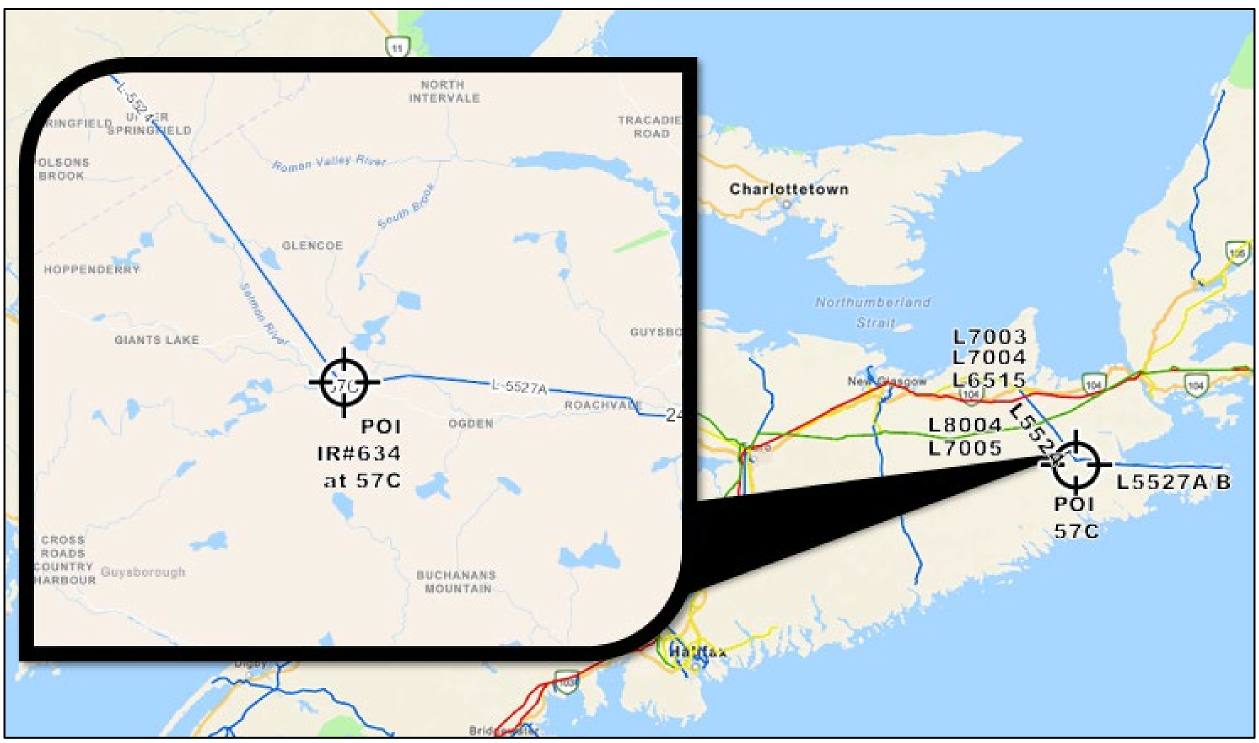

Figure 1 IR#634 Site Location

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

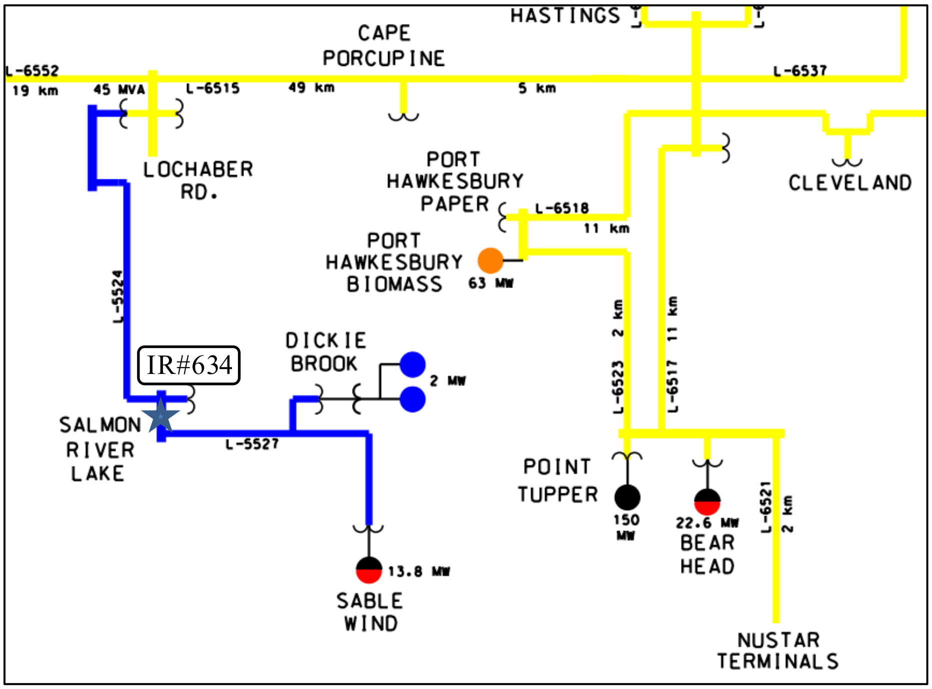

Figure 2: Point of Interconnection (not to scale)

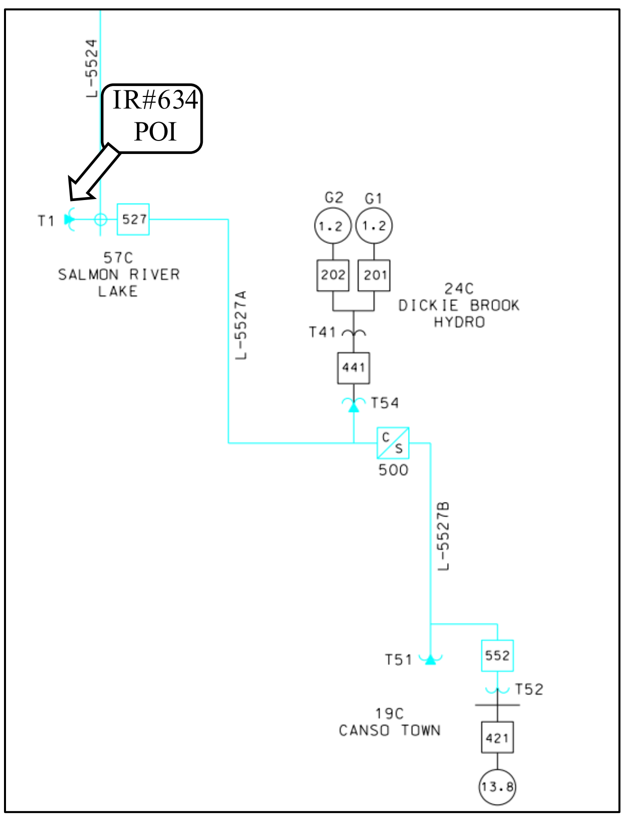

Figure 3: Circuit configuration near POI

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 will be performed to provide the following information:

- Preliminary identification of any circuit breaker short circuit capability limits exceeded because of the interconnection, and any network upgrades necessary to address the short circuit issues associated with the IR. 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 IR#634 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

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

established by NSPI, the Northeast Power Coordinating Council (NPCC), and the North 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.

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. NRIS as per section 3.2 of the Generator Interconnection procedures (GIP).

2. Commercial Operation date 2023-07-01.

3. The Interconnection Customer Interconnection Facility (ICIF) consists of up to 288 Delta M250HV solar PV inverters units, each rated at 0.25 MW AC; capped at a total of 72 MW, connected to collector circuits operating at a voltage of 34.5kV.

4. The POI on 57C-Salmon River Lake 69 kV bus requires one 69 kV circuit breaker and associated equipment for the line connection.

5. The ICIF will require the construction of a 14.5 km 69 kV transmission spur line from the POI to the IC 69kV/34.5kV transformers. The IC will be responsible for providing the Right-of-Way for the lines. Detailed line data was not provided, so typical data was assumed based on 556.5 Dove conductor and 100°C.

6. 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 solar 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.

7. Preliminary data was provided by the IC for the IC substation interconnection facility. Typical impedance data was assumed for the 69kV/34.5kV station transformers. The transformer was rated at 30/75 MVA and modeled with a positive-sequence impedance of 7.0% on 30 MVA with an X/R ratio of 40. The IC indicated these interconnection facility transformers have a delta-wye winding configuration with +/-5% on-load tap changer. The impedance of each generator step-up transformer (GSU) was not provided by the IC and is assumed as 7.0% on 4 MVA with an X/R ratio of 11.4.

8. Collector circuit length was estimated based on the SLD provided by the IC. Detailed collector circuit data was not provided, so typical data was assumed and calculated based on the WECC Equivalent Circuit Calculation method[2]. The understanding is that the net real and reactive power output of the plant will be impacted by losses through transformers and collector circuits.

9. The FEAS analysis assumes that IR's higher in the Generation Interconnection Queue and OATT Transmission Service Queue that have completed a System Impact Study, or that have a System Impact Study in progress will proceed, as listed in Section 4 below.

10. It is assumed that the proposed facility is capable of operating at ambient temperatures as low as -30°C.

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 facilities in the vicinity of IR#634 are shown in Table 2 and Table 3.

Table 2 Local Transmission Element Ratings

Line	Conductor	Design Temp	Limiting Element	Summer Rating Normal/Emergency	Winter Rating Normal/Emergency
L-5524	ACSR 4/0 Penguin	50°C	Trip Settings	19/21 MVA	19/21 MVA
L-5527A	ACSR 2/0 Quail	50°C	CT Ratios	14/15.4 MVA	14/15.4 MVA
L-5527B	ACSR 2/0 Quail	50°C	CT Ratios	14/15.4 MVA	14/15.4 MVA
L-6503	1113 Beaumont	85°C	Switchgear	287/315 MVA	287/315 MVA
L-6511	556.5 Dove	60°C	Conductor	140/154 MVA	184/202 MVA
L-6552	556.5 Dove	50°C	Conductor	110/121 MVA	143/157 MVA
L-6515	556.5 Dove	50°C	Conductor	110/121 MVA	143/157 MVA
L-6537	556.5 Dove	60°C	Conductor	140/154 MVA	184/202 MVA
L-6538	Spec. Galv. Steel/ 556.5 Dove	50°C	Conductor	110/121 MVA	114/125 MVA
L-6539	555.5 Dove	100°C	Switchgear	191/210 MVA	191/210 MVA
L-7003	556.5 Dove	70°C[3]	Conductor	273/303 MVA	345/379 MVA
L-7004	556.5 Dove	60°C	Conductor	233/246 MVA	307/338 MVA
L-7005	1113 Beaumont	70°C	CT Ratio	398/438 MVA	398/438 MVA

[2] https://www.wecc.org/Reliability/WECCPVPlantPowerFlowModelingGuide.pdf
[3] L-7003 is currently being uprated from a design temperature of 60°C to 70°C. This study assumed that the upgrade is complete before IR#634 is in service.

Table 3 Transformer Ratings		
Transformer	Summer Rating Normal/Emergency	Winter Rating Normal/Emergency
4C-T2	44.8/44.8 MVA	44.8/44.8 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 2021-10-25, the following projects are higher queued in the Advanced Stage Interconnection Request Queue and are committed to the study base cases:

- IR426: GIA executed
- IR516: GIA executed
- IR540: GIA executed
- IR542: GIA executed
- IR574: FAC complete
- IR598: FAC in progress

The following projects have been submitted to the Transmission Service Request (TSR) Queue:

- TSR411: SIS in progress
- TSR412: Withdrawn

TSR-411 is a long-term firm point-to-point transmission service reservation in the amount of 550 MW from New Brunswick to Nova Scotia; The TSR is expected to be in service in 2025 and a system study is 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:

> *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.*

5 Short-Circuit Duty / Short Circuit Ratio

The maximum expected (design) short-circuit level is 5,000 MVA (21 kA) on 138kV systems and 3,500 MVA (31.5 kA) on 69 kV systems. The fault current characteristic for this Delta M250HV solar PV inverters is assumed as 1.0 times rated current, or X'd = 1.0 per unit on machine base MVA.

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 4.

Table 4: Short-Circuit Levels. IR#634 on 57C Three-phase MVA (1)		
Location	Without IR#634	With IR#634
Maximum, all transmission facilities in service		
POI on 57C (69kV)	135	197
Interconnection Facility (69kV)	134	197
50N-Trenton (138kV)	2,824	2,832
50N-Trenton (69kV)	1,117	1,118
4C-Lochaber (138kV)	1,157	1,178
4C-Lochaber (69kV)	180	216
Minimum conditions (TC3, LG1, ML In-Service)		
Interconnection Facility (69 kV), all lines in-service	87	149
Interconnection Facility (69 kV), L-6552 open at 4C	81	144
Interconnection Facility (69 kV), L-6515 open at 4C	80	142

(1) Classical fault study, flat voltage profile

The interrupting capability of the 138 kV circuit breakers is at least 2,000 MVA at 4C-Lochaber, and at least 3,500 MVA at 2C-Port Hastings and 50N-Trenton. The interrupting capability of the 69 kV circuit breakers is at least 2000 MVA at 50N-Trenton, 4C-Lochaber, and 2,500 MVA at 57C-Salmon River Lake. As such, the interrupting rating at these substations will not be exceeded by this development on its own.

Inverter-based generation installations often have a minimum Short Circuit Ratio (SCR) for proper operation of converters and control circuits. Based on the calculated short circuit levels, the SCR would be 1.2 at the 69kV Interconnection Facility of the IR#634 substation with all lines in service and IR#634 offline. This falls to 1.1 in minimum load conditions with either L-6552 or L-6515 open at 4C-Lochaber Road. The low system short circuit level could be an issue and the SCR could be below the minimum value recommended by the generator vendor for the model proposed. The impact of the low SCR will be further examined when detailed data for the machine is made available for the SIS.

6 Voltage Flicker and Harmonics

Flicker coefficient information was not provided for the Delta M250HV 0.25 MW solar PV inverters. Voltage flicker will be further examined when data for the machine is made available for the SIS.

Total harmonic distortion (THD) for the Delta M250HV solar PV inverters is indicated less than 3% at nominal apparent power. However, the generator is expected to meet IEEE Standard 519-2014 limiting voltage Total Harmonic Distortion (all frequencies) to a maximum of 5.0%, with no individual harmonic exceeding 3.0% on 69 kV.

7 Load Flow Analysis

The load flow analysis was completed for generation dispatches under system summer peak load and winter peak load conditions which are expected to stress the east-west corridor across the transmission interfaces Cape Breton Export (CBX) and Onslow Import (ONI).

Light load conditions were not studied as solar PV facilities are not expected to generate MW in those periods. Light load typically occurs in the evenings outside the winter peak season.

Generation dispatch was also chosen to represent import and export scenarios that consider expected flows from the existing transmission service reservation associated with the Maritime Link, and scenarios where Maritime Link imports displace NS thermal generation.

The major transmission interfaces/corridors relating to the IR#634 are shown in Figure 4. The nominal interface thermal limits are summarized in Table 5. NSPI relies on Remedial Action Schemes (RAS[4]) approved by NPCC to maintain interface limits. These RAS are armed by system conditions and flow across the respective interfaces and react to pre-determined contingencies to rapidly reduce flow by either tripping generation in Cape Breton or running-back Maritime Link HVdc import.

[4] Also referred to as Special Protection Scheme (SPS),

Figure 4 Major Transmission Interfaces

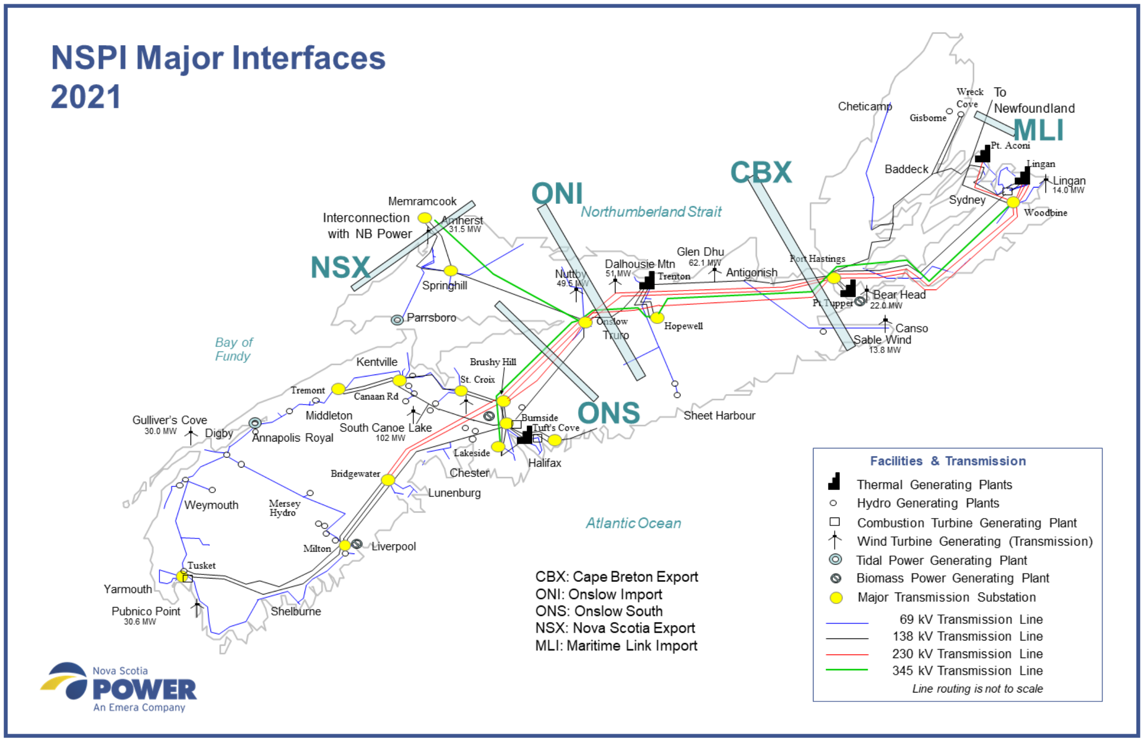

Table 5 Transmission Interface Limits						
Interface	MLI (1)	NSX (2)	NSI (3)	CBX (4)	ONI	ONS (5)
Summer	475	500	Up to 300	875-1075	1075-1275	600-850
Winter	475	500	Up to 300	950-1150	1275	600-975

(1) MLI is limited by simultaneous New Brunswick Import
(2) NS Export to NB (NSX) is dependant on Maritime Link runback RAS
(3) NS import from NB (NSI) is dependant on conditions in NB and PEI, capped at 38% of NS load.
(4) Dependant on generation at Trenton and Point Tupper
(5) Dependant on reactive power reserve in Metro

The cases and dispatch scenarios considered are shown in Table 6. Generation was dispatched to stress local and adjacent corridors. There are no transmission-connected or higher-queued solar PV plants in the area around IR#634, however neighbouring wind and hydro generating facilities are dispatched at full capacity.

Table 6: Base Case Dispatch (MW) IR#634 On-Line								
Case	MLI	NS-NB	CBX	ONI	ONS	LIN	TRE	RAS (1)
SP01	475	333	896	1016	581	296	160	79NG5, 67NG5
SP02	475	0	737	898	795	63	160	-
SP03	475	330	792	826	431	63	0	79NG5
SP04	475	0	662	831	734	198	160	79NG5
SP05	475	0	706	819	711	263	160	-
SP06	475	0	763	777	675	153	0	79NG5
SP07	-100	-225	-153	43	102	63	165	-
WP01	320	150	919	1,189	861	454	324	67NG6
WP02	320	150	880	1130	798	404	324	67NG6
WP03	320	0	716	976	796	404	324	-
WP04	320	150	897	1015	712	428	165	67NG5, 79NG5
WP05	320	150	855	1,130	801	449	324	67NG6
WP06	-100	-100	272	575	560	348	324	-
S - Summer Peak W - Winter Peak LIN – Lingan Gen TRE – Trenton Gen (1) Based on present RAS arming levels								

For NRIS analysis, this FEAS added IR#634 and displaced coal-fired generation in Cape Breton, reducing Cape Breton Export (CBX) transfers while maintaining Onslow Import (ONI) transfers. Single contingencies were applied at the 345 kV, 230 kV, 138 kV and 69 kV voltage levels for the above system conditions with IR#634 interconnected to the POI at 57C. Automated analysis searched for violations of emergency thermal ratings and emergency voltage limits for each contingency. Contingencies studied are listed in Table 7.

Table 7 Contingency List			
Transmission Line	**Transformer / Bus**	**Circuit Breaker Failure**	**Double Circuit Tower**
L-7014, L-7021, L-7022	88S: T71, T72	88S: 710, 711, 713, 690, 721, 722, 723*	L-6534 + L-7021
L-7011, L-7012, L-7015, L-8004*	101S: T81, T82	101S: 701, 702, 703, 704, 705, 706, 711, 712, 713, 811, 812*, 813*, 814, 816	
L-6515, L-6516, L-6537*	2C: B61, B62	4C: 620, 621, 622, 623	

Table 7 Contingency List			
Transmission Line	**Transformer / Bus**	**Circuit Breaker Failure**	**Double Circuit Tower**
L-7003, L-7004, L-7005, L-7019	3C-T71	3C: 710, 712, 713, 715, 716	L-7003+L-7004*
L-6503, L-6613	1N: B61, B62	1N: 600, 613	
L-8001*, L-8002, L-8003*	67N: T71, T81	67N: 701, 702, 7-3, 705, 711, 712, 713, 811*, 812, 813, 814*, 815*	L-7003+L7004
L-6507, L-6508,	79N: T81*	79N: 601*, 606*, 803*, 810*	
	91N: B71	91N: 701, 702, 703	
L-6511, L-6507, L-6508, L-5500, L-5501, L-5502	50N:T12, T8, GT5, GT6	50N: 614, 607, 604, 513, 508, 500	
L-6552	4C: T63, T2	4C: 621, 620, 622, 623	

*Indicates contingency was studied with/without RAS action

Results

With the connection of IR#634, the study shows up to 455% overload on L-5524 and 194% overload on 4C-T2 transformer under system normal conditions during summer, as well as under various contingency conditions; 4C-Locahber Road 69 kV side voltage is below 0.95 p.u. threshold under system normal conditions. These highest overload and low voltages are only listed for system normal conditions in Table 8.

Several contingencies resulted in thermal overloads based on the current function and settings of existing RAS. In most cases, the overloads can be resolved by lowering the arming levels of these RAS without modification of the RAS design. This will increase the probability of a RAS operating and causing a run-back of the Maritime Link or tripping of a thermal unit at Lingan or Point Aconi. Re-design of an RAS, or the addition of a new RAS, is subject to the approval of NPCC.

Table 8 shows the highest thermal overloads found, but other conditions were found which also violated thermal loading criteria, but to a lesser degree.

Table 8 Contingencies Resulting in Highest Line Overload				
Facility ID	**Facility / Line Segment**	**Highest Overload (% of Normal Rating)**	**Case**	**Condition**
4C-T2	Lochaber Road Transformer	Summer/Winter: 194%	SP01	System Normal
L-5524	4C-Lochaber Rd/ 57C-Salmon Lake	Summer/Winter: 445%	SP01	System Normal
Facility ID	**Facility / Line Segment**	**Voltage (p.u.)**	**Case**	**Condition**
4C	4C 69 kV bus	0.85	WP01	System Normal
Line	**Line segment**	**Highest Overload (% of Emergency Rating)**	**Case**	**Contingency**
L-6511	50N-Trenton/ 93N-Glen Dhu	Summer: 108%	SP03	7003/7004 Double Circuit Tower
L-6511	50N-Trenton/ 93N-Glen Dhu	Summer: 110%	SP03	101S-813 or L-8004

For the overloads of 4C-T2 transformer and L-5524 under system normal conditions, transformation capacity upgrade at 4C and L-5524 line rebuild are required for at least 35.4 km at a total cost of $6,925,000, which is classified as Network Upgrades funded by the IC but eligible for refund under the GIP.

Low voltages in the 69 kV system in and around the POI are present during periods when the facility is at full output. This is due to the reactive power capability characteristics of the inverters used in this IR. More detail is explained in Section 8, Reactive Power and Voltage Control.

The following options were examined for the L-6511 overloads (classified as Network Upgrades funded by the IC but eligible for refund under the GIP):

1. Uprate L-6511 from 60°C to 75°C. This line uses a Dove 556.5 kcmil ACSR from 50N-Trenton to 93N-Glen Dhu, approximately 36.5 km. This would increase its summer thermal rating by 24%. The estimated cost is $6,022,000, which includes 10% contingency; or
2. Reduce arming values for existing Group 3, Group 5, and Group 6 RAS, estimated at $50,000 if no functional changes are required.

As an alternative to uprating the affected transmission lines, it is proposed to modify the setting of existing Remedial Action Schemes (RAS) to alleviate most of these overloads.

8 Reactive Power and Voltage Control

In accordance with the *Transmission System Interconnection Requirements* Section 7.6.2, IR#634 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(s). Reactive power can be provided by the asynchronous generator or continually acting auxiliary devices such as STATCOM, DSTATCOM or synchronous condenser, supplied by the Interconnection Customer.

The information (Figure 5) provided by IC indicates that the Delta M250HV solar inverters have a rated power factor of 0.857 lagging and leading (+/- 0.15 Mvar per solar inverter) at the machine terminal voltage of 1.0 p.u. or above, from 10% to 80% of rated power. However, the range of reactive power output is decreased as the real power output of the solar inverter rises above 80% of rated power.

When the solar inverter operates at full real power output, the reactive power output is zero and this IR, in its initial proposed configuration, will not meet Section 7.6.2 of the NSPI Transmission System Interconnection Requirements which requires rated reactive power being available through the full range of real power output of the Generating Facility, from zero to full power.

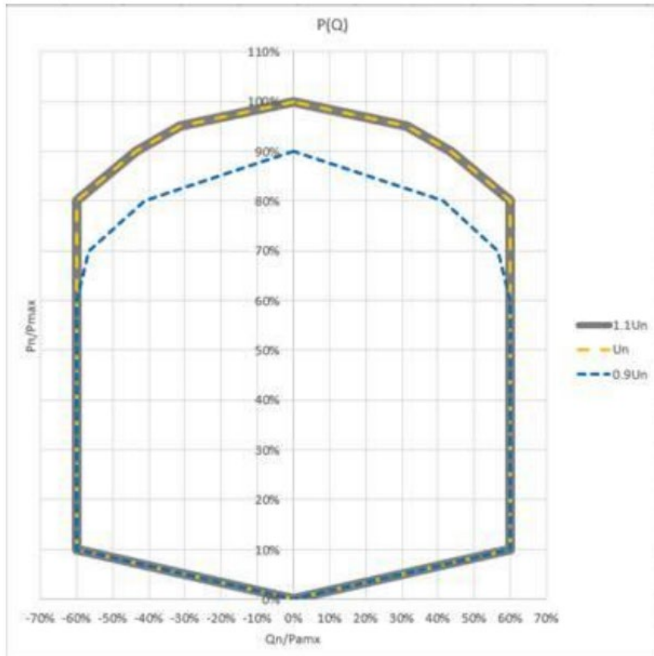

Figure 4 Model Delta M250HV PQ Curve and Reactive Capability

The analysis shown in Figure 5 indicates that IR#634 will not meet the full-load reactive power requirement without additional reactive support. The model shows that with 288 Delta M250HV 0.25 MW solar PV inverters operating at a total 72 MW and 0.0 Mvar (maximum Pgen), the power flow would not converge. For modelling purposes, fictitious reactive power was added to solve the case. This indicates that this configuration would not be able to meet the lagging power factor requirement of 0.95 or leading power factor requirement of -0.95 at the high side of ICIF transformer.

The IC is responsible for designing and implementing their facility with supplemental reactive power support to meet NSPI's power factor requirements, as described in the NSPI Transmission System Interconnection Requirements (TSIR).

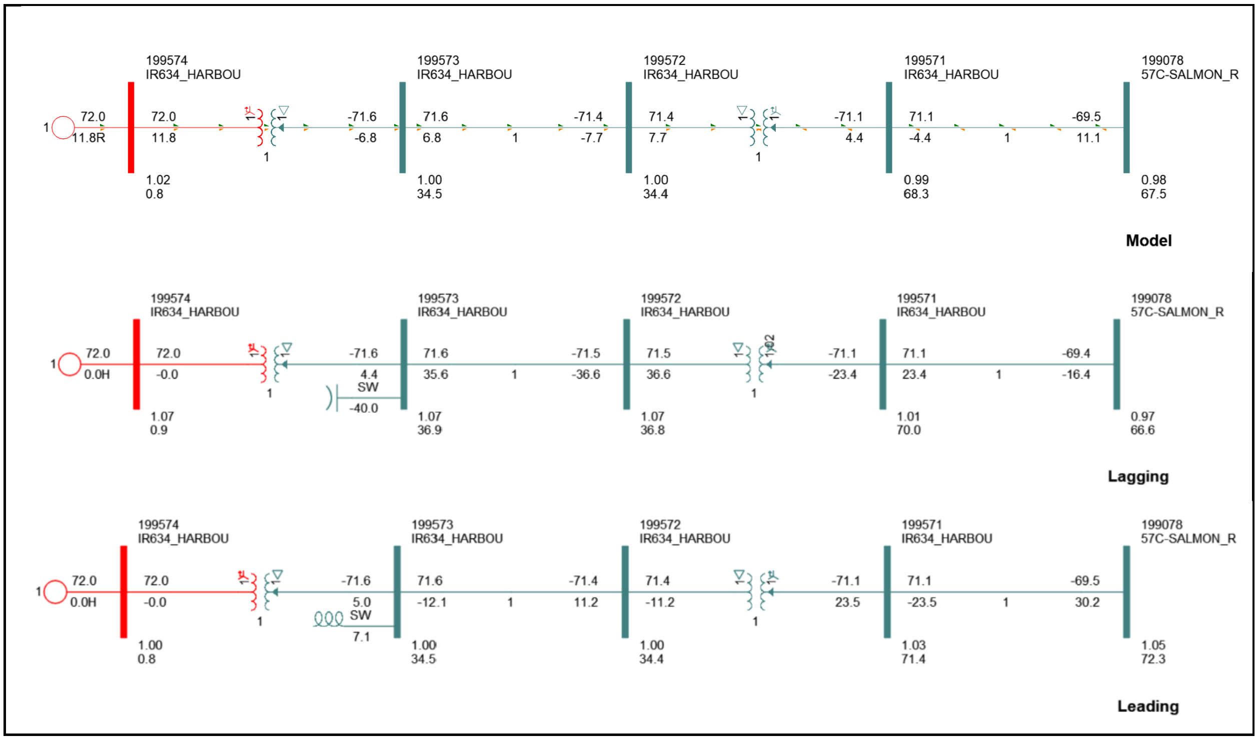

Figure 5: Power Factor Analysis

Because this analysis is based on preliminary transformer data and assumed collector circuit models, reactive capability will be confirmed 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 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

57C-Salmon River Lake presently is not categorized NPCC Bulk Power System or NERC Bulk Electric System. The interconnection of IR#634 will require one 69 kV circuit breaker and associated equipment at 57C. IR#634 is not categorized NERC BES as its POI is operated below 100 kV. Complete NPCC BPS testing will be performed in the System Impact Study (SIS) to determine if it is categorized BPS.

10 Expected Facilities Required for Interconnection

The following facility changes will be required to connect IR#634 to the NSPI transmission system at a POI at 57C under NRIS:

a. Required Network Upgrades

- Transformation capacity upgrade at 4C-Lochaber Road substation.
- Rebuild L-5524 for 36.5 km.
- Modification of NSPI protection systems at 57C-Salmon River Lake.
- Changes to existing NSPI RAS (Group 3, Group 5, and Group 6) arming/limit values. If, during the System Impact Study, it is determined that modifying the existing RAS does not provide an acceptable solution, then uprate of L-6511 will be required.

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

- Install a new 69 kV breaker and associated equipment at the 57C-Salmon River Lake POI.
- Construct a total of 14.5 km transmission spur line between the POI at 57C 69 kV bus and the Interconnection Customer's Interconnection Facility. This line would be built to 69 kV standards.
- Add control and communications between the solar plant and NSPI SCADA system (to be specified).

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

The NSPI Transmission System Interconnection Requirements has a detailed description of ICIF requirements, including:

- 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. The data provided for this study demonstrated this facility requires supplementary reactive power to meet this requirement.
- 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 (TSIR).
- Real-time monitoring (including an RTU) and control of the interconnection facility, with telemetry including local solar plant MW and Mvar, as well as bus voltages.
- 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.
- Automatic Generation Control to assist with tie-line regulation.
- Operation at ambient temperature of -30°C.

11 NSPI Interconnection Facilities and Network Upgrades Cost Estimate

Estimates for NSPI Interconnections Facilities and Network Upgrades for interconnecting 72 MW solar energy at the 69 kV POI at 57C are included in Table 9.

Table 9 Cost Estimate NRIS @ POI 57C		
Item	**Network Upgrades**	**Estimate**
1	P&C modifications at 57C- Salmon River Lake	$200,000
2	Modifications to Group 3, Group 5, Group 6 RAS arm/limit values	$50,000
3	Rebuild L-5524 (36.5 km)	$4,425,000
4	Transformation capacity upgrade at 4C-Lochaber Road	$2,500,000
	Sub-total for Network Upgrades	$7,175,000
Item	**Transmission Provider Interconnection Facilities (TPIF) Upgrades**	**Estimate**
1	Build 14.5 km 69 kV spur line from TPIF to ICIF, with IC responsible to provide right-of-way	$7,250,000
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	$7,560,000
	Total Upgrades	**Estimate**
	Network Upgrades + TPIF Upgrades	$14,735,000
	Contingency (10%)	$1,473,500
	Total (Incl. 10% contingency and Excl. HST)	$16,208,500

The preliminary non-binding cost estimate for interconnecting 72 MW at the POI of 57C under NRIS is $16,208,500 including a contingency of 10%. In this estimate, $7,175,000 (plus 10% contingency) of the amount represents Network Upgrade costs which are funded by the Interconnection Customer, but which are eligible for refund under the terms of the GIP. This does not include TBD costs to address any stability issues identified at the SIS stage based on dynamic analysis.

The estimated time to construct the Transmission Providers Interconnection Facilities and any Network Upgrades is 18-24 months after receipt of funds and cleared right of way from the customer.

12 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#634 in service, losses in the winter peak case total 86.2 MW. With IR#634 in service at the POI of 57C and not including losses associated with the IR#634 Generation Facilities or TPIF, system losses total 98.8 MW, an increase of 12.6 MW.

The power delivered to the POI is 69.4 MW, therefore the loss factor is calculated as 12.6/69.4 = +18.2%. Part of this is due to the high losses along the 69 kV network and the transformation to the 138 kV network.

13 Issues to be addressed in SIS

The following provides a preliminary scope of work for the subsequent SIS for IR#634. 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 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:

- Facilities that the customer must install to meet the requirements of the GIP and the *Transmission System Interconnection Requirements*.
- 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.
- Guidelines and restrictions applicable to first contingency operation (curtailments etc.).
- Under-frequency load shedding impacts.

The SIS will assess system contingencies such that the system performance will meet the following criteria:

- Table 1 “Planning Design Criteria” of NPCC Directory 1.
- Table 1 “Steady State & Stability Performance Planning Events” of NERC TPL-001-4.
- NSPI System Design Criteria, report number NSPI-TPR-003-4.

Additionally, electromagnetic transient study may be required to account for IR#634 control system to coordinate with other facilities in the transmission system and to ensure fault ride through.

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[5] and NPCC[6] criteria as well as NSPI guidelines and good utility practice. The SIS will also determine the contingencies for which this facility must be curtailed.

Nova Scotia Power
Transmission System Operations
2022-04-08

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