System Impact Study Report
GIP-IR597-SIS-R0

Generator Interconnection Request 597
36 MW Wind Facility
Queens County, NS

2022-10-21

Control Centre Operations
Nova Scotia Power Inc.

Executive Summary

This System Impact Study report (SIS) presents the results for a 36 MW wind turbine generation facility interconnected to the NSPI system as Network Resource Interconnection Service (NRIS). The study performed analyses on the impact of the proposed development on the NS Power grid.

System studies including short circuit, power factor, voltage flicker, steady state, stability, NPCC Bulk Power System (BPS), NERC Bulk Electric System (BES), under-frequency operation, low voltage ridethrough, and loss factor calculation were performed applying NSPI and NPCC planning criteria.

This project is designated as Interconnection Request #597 in the NSPI Interconnection Request Queue and will be referred to as IR597 throughout this report. The proposed Commercial Operation Date is 2023/08/31.

The Interconnection Customer (IC) identified a 138 kV bus at 50W-Milton as the Point Of Interconnection (POI). This wind generation facility will be interconnected to the POI via an approximately 5.3km long 138 kV transmission line from the Point of Change of Ownership (PCO).

There is one relevant long-term firm Transmission Service Reservations (TSR) in the Facilities Study stage in the Transmission Service Queue, with requested in-service date of 2025/01/01. This is TSR411 (550 MW from NB to NS) and is expected to alter the configuration of the Transmission System in Nova Scotia. The configuration changes associated with this TSR are not expected to negatively impact the IR597 site, however, the decreased short circuit levels associated with the TSR411 modifications may require further EMT (Electromagnetic Transient) level analysis to ensure the IR597 site is able to operate effectively.

There are no concerns regarding increased short circuit levels as a result of IR#597. The increase in short circuit level is still within the capability of associated breakers. The minimum short circuit level at the Interconnection Facility's (IF) high side bus is 580 MVA. The Short Circuit Ratio (SCR) in minimal generation conditions is approaching the Vestas V150's minimum levels. As a result, this information should be provided to Vestas for design specification consideration as the collector circuit and generator step-up transformers further reduce the SCR measured at the wind turbines' HV terminals.

IR597 currently meets the lagging power factor requirement based on the supplied transformer information and assumed collector circuit impedance. It is just on the threshold, however, and should be re-evaluated when final transformer impedances and collector circuit design are determined.

IR597 meets NS Power's required short term and long-term voltage flicker requirements based on the supplied calculated data based on Vestas V150-4.2 MW machines at 50 Hz, with the assumption that the Vestas V150-4.5 MW model does not differ significantly in terms of voltage flicker performance.

This study's steady state power flow analysis did not identify any transmission contingencies inside Nova Scotia which would violate thermal loading criteria or voltage criteria. This study determined there are no necessary Network Upgrades for NRIS operation. It is concluded that the incorporation of the proposed facility into the NS Power Transmission System at the specified location has no negative impacts on the reliability of the NS Power grid, provided the recommendations provided in this report are implemented.

IR597 was not found to cause issues with the stability of the interconnected system. IR597 is neither classified as part of the Bulk Power System according to NPCC, nor the Bulk Electric System according to NERC. IR597 was found to comply with Low Voltage Ridethrough requirements and remained online through simulated under frequency islanding events.

The loss factor is calculated as 0.52% with IR597 modelled in the winter peak case.

The total high-level cost estimate for interconnecting IR597 to the 50W-Milton 138 kV bus as NRIS is $4,565,000. The entirety is TPIF costs, which includes a 10% contingency. This estimate will be further refined in the Facility (FAC) study.

The estimated time to construct the TPIF for NRIS operation is 18-24 months after the receipt of funds.

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1.0 Introduction

This System Impact Study report (SIS) presents the results of a System Impact Study Agreement for the connection of a 36 MW (originally 33.6 MW) wind generation facility interconnected to the NSPI system as Network Resource Interconnection Service (NRIS).

This project is listed as Interconnection Request #597 in the NSPI Interconnection Request Queue and will be referred to as IR597 throughout this report. The proposed Commercial Operation Date is 2023/08/31.

The Interconnection Customer (IC) identified a 138 kV bus at 50W-Milton as the Point of Interconnection (POI). This wind generation facility will be interconnected to the POI via a 5.3 km long 138 kV transmission line from the Point of Change of Ownership (PCO). Figure 1 shows the approximate location of the proposed IR597 site.

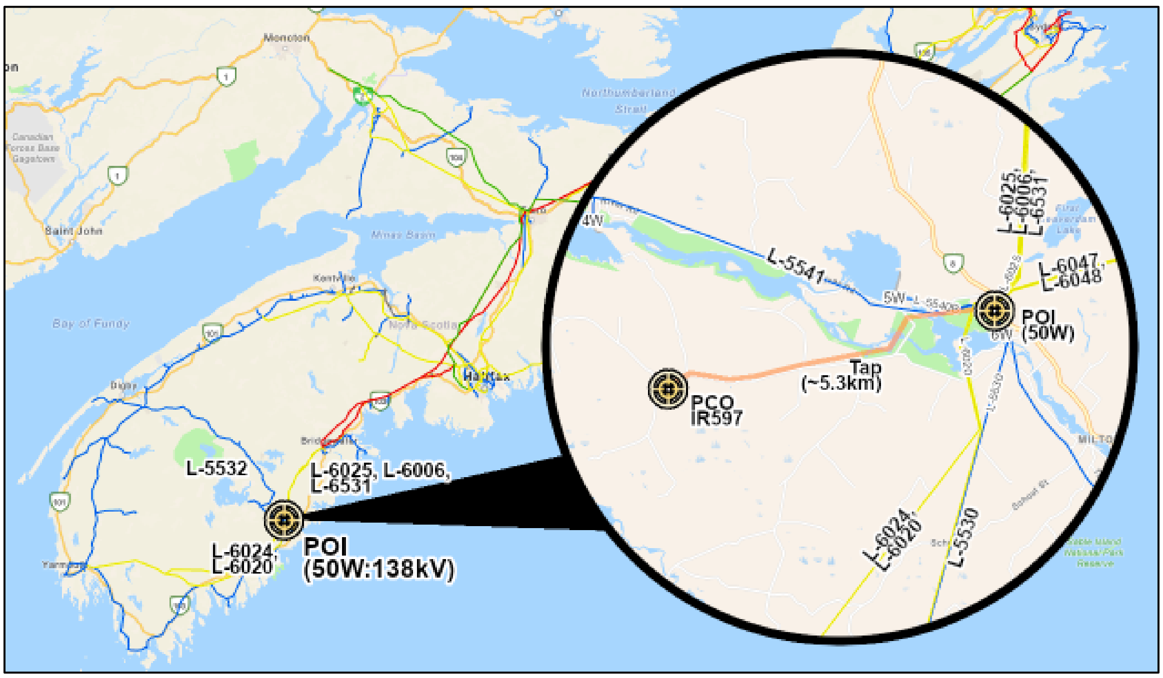


Figure 1: IR597 approximate geographic location

1.1 Scope

This report's objective is to presents the results of the SIS with the objective of assessing the impact of the proposed generation facility on the NS Power Transmission System. The scope of the SIS is limited to determining the impact of the IR597 generating facility on the NS Power transmission for the following:

- Short circuit analysis and its impact on circuit breaker ratings.
- Power factor requirement at the high side of the ICIF transformer.
- Voltage flicker.

- Steady state analysis to determine any thermal overload of transmission elements or voltage criteria violation.
- Stability analysis to demonstrate that the interconnected power system is stable for various single-fault contingencies.
- NPCC Bulk Power System (BPS) and NERC Bulk Electric System (BES) determination for the substation.
- Underfrequency operation.
- Low voltage ridethrough.
- Incremental system Loss Factor.
- Impact on any existing Remedial Action Schemes (RASs).

This report provides a high-level non-binding cost estimate of requirements for the connection of the generation facility to ensure there will be no adverse effect on the reliability of the NS Power Transmission System. An Interconnection Facilities Study (FAC) follows the SIS in order to ascertain the final cost estimate to the interconnect the generating facility.

1.2 Assumptions

The study is based on technical information provided by the IC in addition to the following assumptions:

1. Network Resource Interconnection Service (NRIS) per section 3.2 of the Generation Interconnection Procedures (GIP).
2. Commercial Operation date: 2023/08/31.
3. The Interconnection Facility consists of eight (8) Vestas V150-4.5 MW wind energy converters, totalling 36 MW. These are modelled as Type 4 inverter based generators, evenly split between two collector circuits.
4. The IC identified the POI at one of the 50W-Milton substation's 138 kV buses.
5. The proposed 138 kV transmission line from the POI (50W) to the PCO is 5.3 km of 556 ACSR Dove conductor with OHGW.
6. Data was provided by the IC for the substation step-up transformer and generator step-up transformers.

   6.1. The substation step-up transformer was modelled as one (1) 138 kV (wye) - 34.5 kV (wye) transformer rated at 30/40/50 MVA, with a positive sequence impedance of 8.5% and 20.0 X/R ratio.

   6.2. The generator step-up transformers were modelled as an equivalent transformer based off eight (8) 34.5 kV (delta) - 0.720 kV (grounded wye) 5.3 MVA transformers, with a 9.9% positive sequence impedance and 12.375 X/R ratio.
7. A generic collector circuit layout is assumed since a collector circuit design was not provided. Note the plant's net real and reactive power will be impacted by losses through the transformers and collector circuits.

8. The SIS analysis is based on the assumption that IRs higher in the Generation Interconnection Queue and OATT Transmission Service Queue that have a completed System Impact Study, or have a System Impact Study in progress, will proceed as listed in Section 4.0: Project queue position.
9. It is assumed that IR597 generation meets IEEE Standard 519, limiting total harmonic distortion (all frequencies), to a maximum of 5% with no individual harmonic exceeding 1%.
10. Transmission line ratings used in this study are listed in *Appendix A: Transmission line ratings*.

1.3 Project Queue Position

All in-service generation is included in this FEAS.

As of 2022/07/22, the following projects are higher queued in the Advanced Stage Interconnection Request Queue and are included in this study's base cases:

- IR426: GIA executed
- IR516: GIA executed
- IR540: GIA executed
- IR542: GIA executed
- IR557: SIS complete
- IR569: GIA executed
- IR566: GIA executed
- IR574: GIA executed
- IR598: GIA executed
- IR604: GIA executed
- IR603: GIA executed
- IR600: GIA executed

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

- TSR 411: Facilities Study in Progress
- TSR 412: Withdrawn
- TSR 413: Withdrawn

TSR 411 has an expected 01/01/2025 in service date and a Facilities Study (FAC) to determine required upgrades to the NS transmission system is currently in progress.

2.0 Technical Model

To facilitate the power flow analysis, a windfarm equivalent was created for the 8 machines, their step-up transformers, and collector circuits. This was based on the 720V machine terminal voltage that was stepped up to 34.5kV for transmission along the collector circuits to the IR597 substation. The IR597 substation is modelled where voltage is stepped up to 138kV to the spur line, approximately 5.3km in length, to the POI at the 50W-Milton substation.

The PSSE model for power flow is shown in Figure 2. Data for the individual 34.5/0.72 kV transformers is based on 9.9% impedance on 5.3MVA with a 12.375 X/R ratio. The ICIF transformer is based on 8.5% impedance on 30 MVA ONAN rating with a 20 X/R ratio.

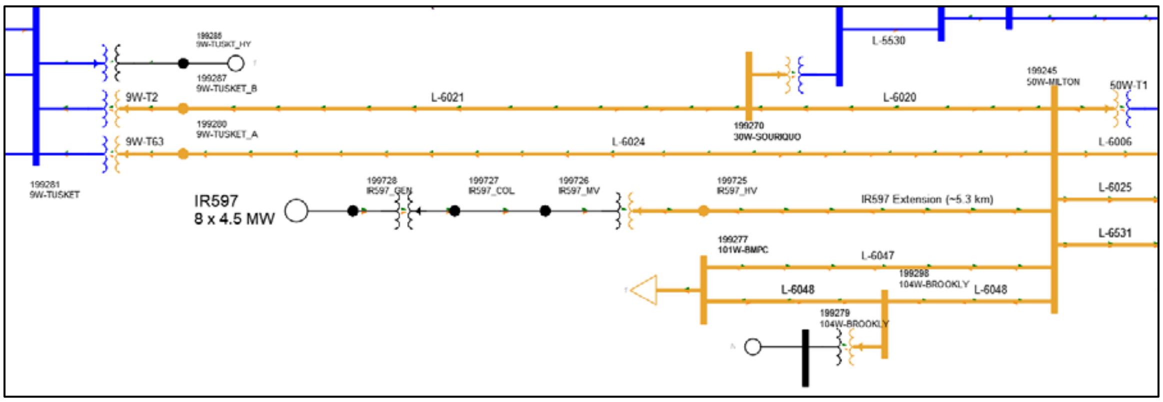


Figure 2: Proposed Interconnection of IR597

2.1 System Data

The data source used to develop the base cases for this study was the "2022 10-Year System Outlook" report, dated 2022/06/30. The winter peak demand, including Demand Side Management (DSM) effects is shown in Table 1: Load forecast for study period.

The other forecasts are derived from the winter peak load forecast using historic load patterns that resulted in the following scaling factors:

- Summer: 70%
- Light load: 39%

Table 1: Load forecast for Study Period

Year	Interruptible Contribution to Peak (MW)	Demand Response (reduction in Firm Peak only, MW)	Firm Contribution to Peak (MW)	System Peak (MW)	Growth (%)
2022	144	-	2021	2165	-
2023	146	-4	2035	2185	0.9
2024	146	-12	2057	2215	1.4
2025	152	-24	2076	2253	1.7
2026	154	-36	2101	2291	1.7

The load forecast is projecting a slight increase in forecasted non-firm (interruptible) and moderate increase in firm peak demand (0.9% - 1.7%). DSM, AMI-enabled peak reduction strategies, and efficiency improvements are accounted for in the Demand Response column and are expected to offset a portion of the residential and industrial growth for the near future. Steady overall load growth (~1.5-2%) between 2024 and 2032 is forecasted.

Load conditions for 2023 were used in this study because the lower peak load demand is more critical to the analysis in the region around IR597. Based on its location (West of Metro), Transmission System impacts are likely to be seen in Spring and Fall conditions, rather than winter.

Base cases for this SIS were selected to stress overall system and local conditions, with most of them at or below 1,500 MW, approximately 70% of winter peak. This is derived from Spring conditions, where Western and Valley hydro resources are dispatched at their highest values.

2.2 Generating Facility

IR597 will have 8 Vestas V150-4.5 MW wind turbine generators, each rated at 4.5MW. Each unit will generate at 720V and be transformed to 34.5kV on two collector circuits, which will be further transformed to 138kV to connect to the NS Power Transmission System.

The 138/34.5 kV ICIF (Interconnection Customers Interconnection Facilities) transformer is rated 30/40/50 MVA, Y/Y with Δ tertiary, OLTC with +/- 10% taps (32 equal steps), and 8.5% impedance based on 30 MVA. The results of this SIS will be reviewed if a change is made to the rating or impedance of the ICIF transformer.

The proposed generator is classified as Type 4, with fully rated AC-DC-AC converter. It is assumed to be equipped with a Supervisory Control and Data Acquisition (SCADA) based central regulator which controls the individual generator reactive power output to maintain constant voltage at the ICIF substation. The Vestas V150-4.5 MW wind turbines are each capable of a reactive power range of +1530 to -1440 kVAR within 90% to 110% of 720V nominal (+2550 to -1600 kVAR at 100% of 720V nominal).

2.3 System Model & Methodology

Testing and analysis were conducted using the following criteria, software, and/or modelling data.

2.3.1 Short Circuit

PSSE 34.8, classical fault study, flat voltage profile at 1 PU voltage, and 3LG fault was used to assess before and after short circuit conditions. The 2023 system configuration with IR597 in service and out of service was studied, with comparison between the two.

2.3.2 Power Factor

The Standard Generator Interconnection Procedures (GIP) requires a net power factor of ±0.95 measured at the high voltage bus of the ICIF transformer. PSSE was used to simulate high and low system voltage conditions to determine the machine capability in delivery/absorption of reactive power (VAR).

2.3.3 Voltage Flicker

Voltage flicker contribution is calculated in accordance with the methodology described in CEATI Report No. T044700-5123 "Power Quality Impact Assessment of Distributed Wind Generation".

Short-term flicker severity (P_{st}) and long-term flicker severity (P_{lt}) calculations are at the WTG terminals. For multiple wind turbines at a single plant, the estimated flicker contribution is calculated as follows:

Continuous:

$$P_{st} = P_{lt} = \left(\frac{1}{S_k}\right) \sqrt[m]{\sum_{i=1}^{N_{wt}} \left[\left(c_i(\varphi_k, v_a)(S_{n,i})\right)\right]^m}$$

Switching Operation:

$$P_{st\Sigma} = \left(\frac{15}{S_k}\right) \sqrt[3.2]{\sum_{i=1}^{N_{wt}} \left[(N_{10,i})\left(k_f(\varphi_k)(S_{n,i})\right)\right]^{3.2}}$$

$$P_{lt\Sigma} = \left(\frac{6.9}{S_k}\right) \sqrt[3.2]{\sum_{i=1}^{N_{wt}} \left[(N_{120,i})\left(k_f(\varphi_k)(S_{n,i})\right)\right]^{3.2}}$$

Where:

- $\mathbf{S_k}$ = short-circuit apparent power at the high voltage side of the ICIF transformer. As calculations are for the flicker contribution for the addition of IR597 to the existing system, short-circuit values are for the existing system - before the addition of IR597.
- **m** = 2 in accordance with IEC 61400-21 for WTGs.
- $\mathbf{N_{wt}}$ = number of WTGs at IR597.
- $\mathbf{N_{10,i}}$ and $\mathbf{N_{120,i}}$ = number of switching operations of the individual wind turbine within a 10 and 120 minute period, respectively.

- $\mathbf{c_i(\psi_k,v_a)}$ = flicker coefficient of the wind turbine for the given network impedance angle, ψ_k, at the PCC, for the given annual average wind speed, v_a, at the hub-height of the wind turbine site. It is to be provided by the wind turbine supplier. NS network impedance angle is typically 80º-85º.
- $\mathbf{k_{f,i}(\psi_k)}$ = flicker step factor of the individual wind turbine.
- $\mathbf{S_{n,i}}$ = rated apparent power of the individual wind turbine.

NS Power's requirement is $P_{st} \leq 0.25$ and $P_{lt} \leq 0.35$.

2.3.4 Generation Facility Model

Modelling data provided was provided by the IC for PSSE steady state and stability analysis in this SIS. The 8 wind turbines and 2 collector circuits were grouped as a single equivalent generator with an equivalent impedance line.

2.3.5 Steady State

Analysis was performed in PSSE using Python scripts to simulate a wide range of single contingencies, with the output reports summarizing bus voltages and branch flows that exceeded established limits.

System modifications and additions up to 2023 were modelled to develop base cases to best test system reliability in accordance with NS Power and NPCC design criteria:

- Light load; low Western Valley generation.
- Medium load; high and low Western Valley generation.
- Peak load.

Power flow was run with the contingencies on each of the base cases listed in Section 3.4; with IR597 in and out of service to determine the impact of the proposed facility on the performance criteria and reliability of the NS Power grid.

2.3.6 Stability

Positive sequence RMS dynamic analysis was performed using PSSE for the 2023 study year and system configuration. Spring light load, Fall, Summer peak, and Winter peak were studied for contingencies that provide the best measure of system reliability. Details on the contingencies studied are provided in Section 3.5. The system was examined before and after the addition of IR597 to determine its impact.

Note all plots are performed on 100 MVA system base.

2.3.7 NPCC-BPS / NERC-BES

NS Power is required to meet reliability standards developed by the Northeast Power Coordinating Council (NPCC) and the North American Electric Reliability Corporation (NERC). Both NPCC and NERC have more stringent requirements for system elements that can have impacts beyond the local area. These elements are classified as "Bulk Power System" (BPS) for NPCC, and "Bulk Electric System" (BES) for NERC.

2.3.7.1 NPCC-BPS

NPCC's BPS substations are subject to stringent requirements like redundant and physically separated protective relay and teleprotection systems. Determination of BPS status was in accordance with NPCC criteria document A-10: Classification of Bulk Power System Elements, 2020/03/27. The A-10 test requires steady state and stability testing.

The stability test involves simulation of a permanent 3PH fault at the bus under test with all local protection out of service (such as station battery failure), including high speed teleprotection to the remote terminals. The fault is maintained on the bus for enough time to allow remote zone 2 protection to trip the faulted bus, and the post-fault simulation is extended to 20 seconds.

The steady state test involves opening all elements connected to the bus under test in constant MVA power flow, as well as disconnecting all units which tripped during the stability test.

A bus will be classified as part of the BPS if any of the following is observed during the steady state and/or stability tests:

- System instability that cannot be demonstrably contained with in the Area.
- Cascading that cannot be demonstrably contained within the Area.
- Net loss of source/load greater than the Area's threshold.

The NPCC A-10 Criteria document does not require rigorous testing of all buses. Section 3.4, item 2 states:

> *"...For buses operated at voltage levels between 50 kV and 200 kV, all buses adjacent to a bulk power system bus shall be tested. Testing shall continue into the 50-200 kV system until a non-bulk power system result is obtained, as detailed in Section 3.5. Once a non-bulk power system result is obtained, it is permitted to forgo testing of connected buses unless one of the following considerations shows a need to test these buses:*
> *- Slower remote clearing times.*
> *- Higher short-circuit levels..."*

The 138 kV bus at 50W-Milton substation identified as the POI for IR597 is not adjacent to a BPS bus.

2.3.7.2 NERC-BES

NERC uses Bulk Electric System (BES) classification criteria based on a "bright-line" approach rather than performance based like the NPCC BPS classification. The NERC

Glossary of Terms as well as the methodology described in the NERC Bulk Electric System Definition Reference was used to determine if IR597 should be designated BES or not.

2.3.8 Underfrequency Operation

Underfrequency dynamic simulation is performed to demonstrate that NS Power's automatic Underfrequency Load Shedding (UFLS) program sheds enough load to assist stabilizing system frequency, without tripping IR597's generators.

This test is accomplished by triggering a sudden loss of generation by placing a fault on L-8001 under high import conditions.

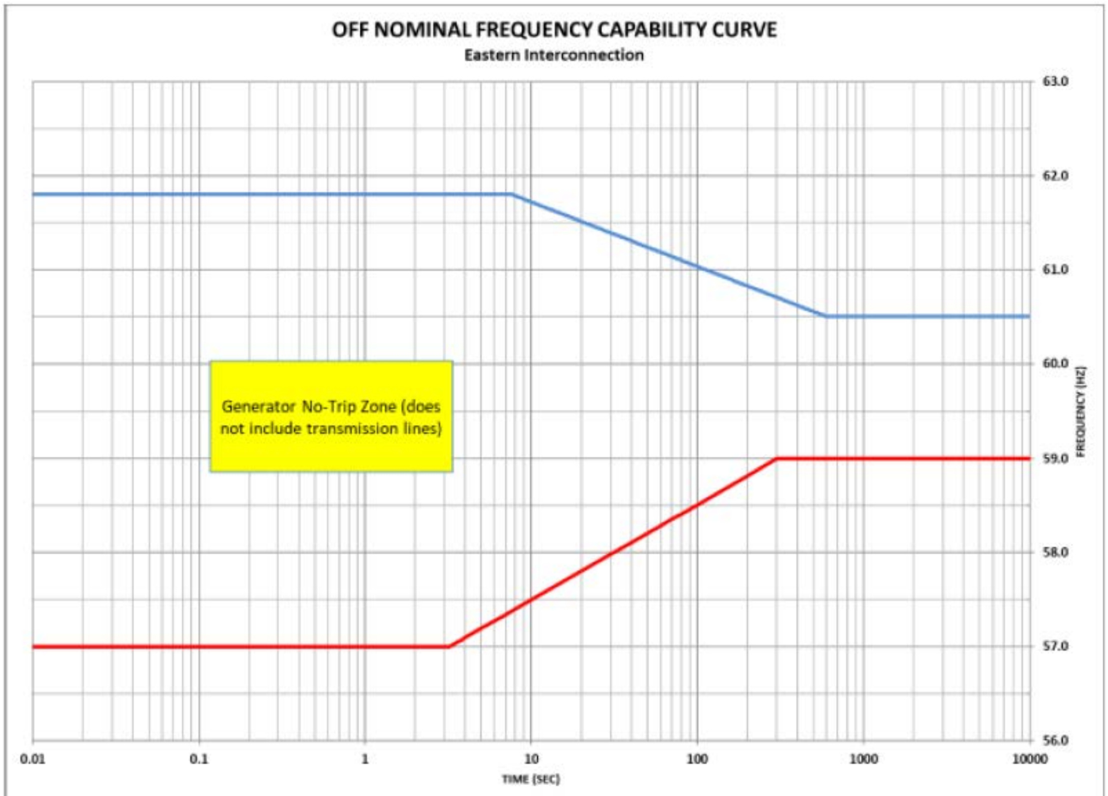
Nova Scotia is connected to the rest of the North American power grid by the following three AC transmission lines:

- L-8001 (345kV)
- L-6535 (138kV)
- L-6536 (138kV)

Under high import conditions, if L-8001, or, either of L-3025 and L-3006 in New Brunswick trips, an "Import Power Monitor" RAS (SPS) will cross-trip L-6613 at 67N-Onslow to avoid thermal overloads on the in-service 138kV transmission lines. This controlled separation will island Nova Scotia from the rest of the North American power grid. System frequency will be stabilized from the resulting generation deficiency through Under-Frequency Load Shedding (UFLS) schemes to shed load across Nova Scotia. IR597 is required to remain online and not trip under this scenario.

Other contingencies in New Brunswick and New England can also result in under-frequency islanded situation in Nova Scotia.

In addition to the test, IR597 must be capable of operating reliably for frequency variations in accordance with NERC Standards PRC-024-2 and PRC-006-NPCC-2 as shown in Figure 2. It should also have the capability of riding through a rate of change of frequency of 4 Hz/s.



High Frequency Deviation		Low Frequency Deviation	
Frequency (Hz)	Time (Sec)	Frequency	Time
≥ 61.8	Instantaneous Trip	f ≥ 57.0 Hz	t ≤ 3.3 s
< 61.8 ≥ 60.5	$10^{(90.935 - 1.45713 * f)}$	f ≥ log(t) + 56.5 Hz	3.3s < t ≤ 300 s
< 60.5	Continuous Operation	f ≥ 59.0Hz	t > 300 s

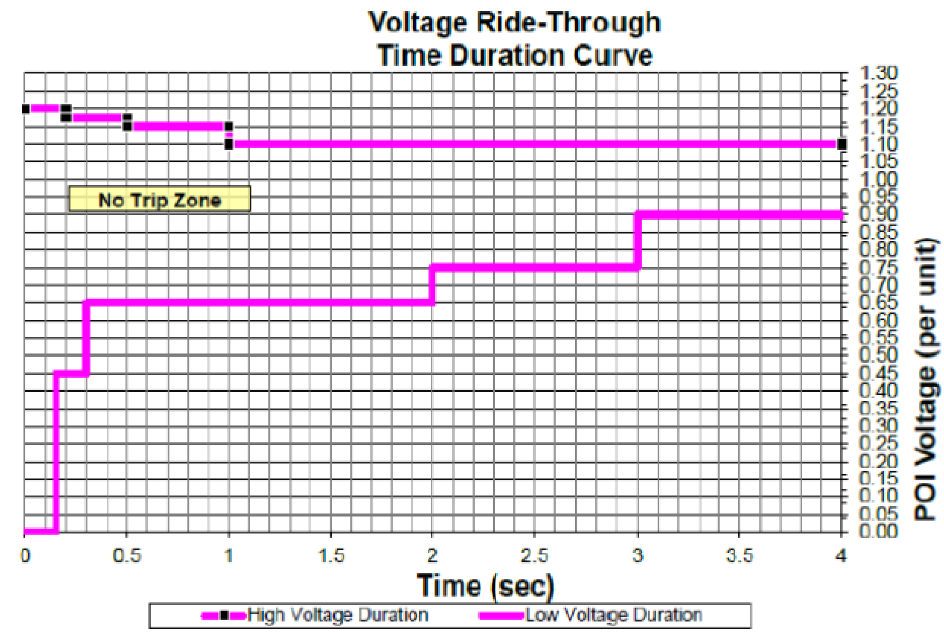
Figure 3: Off-nominal frequency curve (PRC-024-2 and PRC-006-NPCC-2 combined)

2.3.9 Voltage Ridethrough

IR597 must remain operational under the following voltage conditions:

- Under normal operating conditions: 0.95 PU to 1.05 PU
- Under stressed (contingency) conditions: 0.90 PU to 1.10 PU
- Under the voltage ridethrough requirements in NERC Standard PRC-024-2, see Figure 3.

This test is performed by applying a 3-phase fault to the HV and LV buses of the ICIF for 9 cycles. IR597 should not trip for faults on the Transmission System or its collector circuits.



Low Voltage Ride-Through Data Points	
Bus Voltage at Point of Interconnection (pu)	**Duration (sec)**
< 0.45	0.15
< 0.65	0.30
< 0.75	2.00
< 0.90	3.00
High Voltage Ride-Through Data Points	
Bus Voltage at Point of Interconnection (pu)	**Duration (sec)**
≥1.200	Instantaneous trip permitted
≥1.175	0.2
≥1.150	0.5
≥ 1.100	1.00

Figure 4: PRC-024-2 Attachment 2: Voltage ridethrough requirements

2.3.10 Loss Factor

Loss factor was calculated by running the power flow using a standardized winter peak base case with and without IR597, while keeping 91H-Tufts Cove generation as the NS area interchange bus. The loss factor for IR597 is the differential MW displaced or increased at 91H-Tufts Cove generation calculated as a percentage of IR597's nameplate MW rating. Although the IR under study is tested at maximum rated output, all other (existing or committed) wind generation facilities are dispatched at an average 30% capacity factor.

This methodology reflects the load centre in and around 91H-Tufts Cove and has been accepted and used in the calculation of system losses for the Open Access Transmission

Tariff (OATT). It is calculated on the hour of system peak as a means for comparing multiple projects but not used for any other purpose.

Because of the uncertainty of the collector circuit design and transformer equipment specification, loss factors are provided at the high side of the ICIF transformer.

3.0 Technical Analysis

The results of the technical analysis are reported in the following sections.

3.1 Short Circuit

IR597 will not impact 50W-Milton and neighbouring breaker's interrupting capability based on this study's short circuit analysis. Analysis was performed using PSS/e 34.8, classical fault study, flat voltage profile at 1.0 PU voltage, and 3LG faults.

The maximum (design) interrupting capability of the neighbouring 138 kV circuit breakers are at least 5,000 MVA. The Vestas V150-4.5 MW technical bulletin supplied the short circuit characteristics in *Table 2: Vestas V150-4.5 MW operational characteristics*. The short circuit levels in the area before and after this development are provided in *Table 3: Short circuit levels, 3-ph, in MVA.*

Table 2: Vestas V150-4.5 MW operational characteristics

Characteristic	Value
Minimum Required Short Circuit Ratio at Turbine HV Connection	5.0 (contact Vestas for lower SCR levels)
Maximum Short Circuit Contribution*	1.05 PU (continuous) 1.45 PU (peak)

**Assumed the same as the Vestas V150-4.2 MW model. No information was provided for the V150-4.5 MW model.*

Table 3: Short circuit levels, 3-ph, in MVA

Location	IR597 not in service	IR597 in service	Post % increase
2023, max generation, all facilities in service			
50W-Milton POI:138kV	1309	1340	2%
IR597-IC tap PCO:138kV	1114	1146	3%
IR597-LV:34.5kV	268	303	12%
2023, min generation, all facilities in service			
50W-Milton POI:138kV	700	731	4%
IR597-IC tap PCO:138kV	640	672	5%
IR597-LV:34.5kV	228	262	13%
2023, min generation, L6025 OOS			
50W-Milton POI:138kV	629	660	5%
IR597-IC tap PCO:138kV	580	611	5%
IR597-LV:34.5kV	220	254	13%

The minimum Short Circuit Ratio (SCR) specified in the IR documentations for IR597 is 5.0 at the turbine's HV terminals. Minimum fault levels occur when L-6025 (138 kV line from 50W-Milton to 99W-Bridgewater) is out of service. In this scenario, the SCR at the low side of IR597's substation step down transformer is calculated as 6.1 (220 MVA / 36 MW) at IR597's 34.5 kV bus. This information should be provided to Vestas for design specification as the collector circuit length and generator step-up transformers may further reduce the SCR measured at the wind turbines' HV terminals.

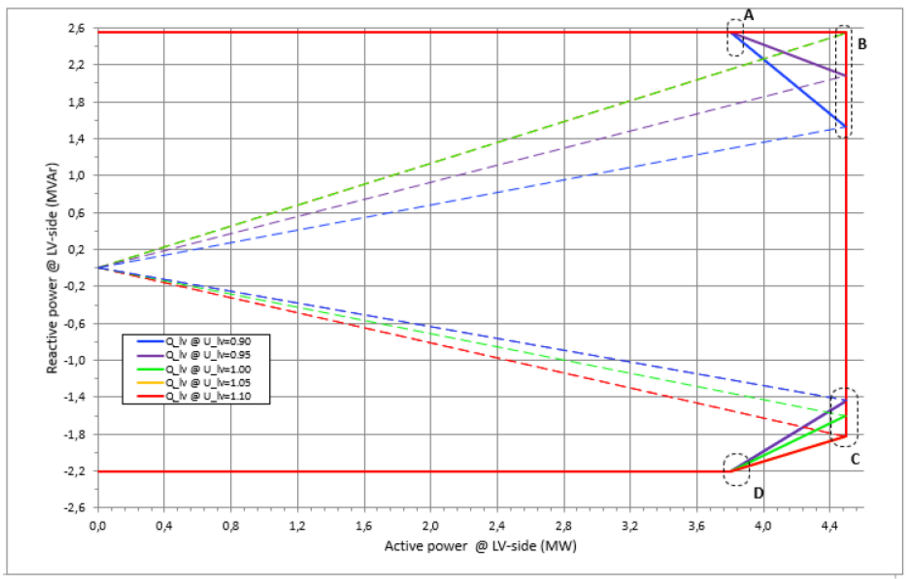
3.2 Power Factor

At all production levels up to the full rated load, the IR597 facility must be capable of operating between 0.95pu lagging to 0.95pu leading net power factor at the high side of the ICIF transformer.

Information provided by the IC, the 138/34.5 kV transformer has an on-load tap changer with ±10% taps and 32 equal steps. The 34.5/0.72 kV generator step-up transformers were noted to be supplied with off-load de-energized tap changers with ±2.5% taps.

10.5 Operational Envelope – Reactive Power Capability in 4.5 MW PO4

The reactive power capability for the 4.5 MW Power Optimized Mode (PO4) is as illustrated in Figure 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 = 0.90 p.u. voltage	3,800	2,550	4,500	1,530	4,500	-1,440	3,800	-2,200	0,947	0,952
Reactive power [kVAr] @ LV side @ U_lv = 0.95 p.u. voltage	3,800	2,550	4,500	2,080	4,500	-1,440	3,800	-2,200	0,908	0,952
Reactive power [kVAr] @ LV side @ U_lv = 1.00 p.u. voltage	3,800	2,550	4,500	2,550	4,500	-1,600	3,800	-2,200	0,870	0,942
Reactive power [kVAr] @ LV side @ U_lv = 1.05 p.u. voltage	3,800	2,550	4,500	2,550	4,500	-1,830	3,800	-2,200	0,870	0,926
Reactive power [kVAr] @ LV side @ U_lv = 1.10 p.u. voltage	3,800	2,550	4,500	2,550	4,500	-1,830	3,800	-2,200	0,870	0,926

Figure 5: Reactive power capability for 4.5 MW Power Optimized Mode (PO4).

Figure 5: Vestas V150 4.5 MW reactive power capability[1]

[1] Vestas General Description 4MW platform (4.5MW), document no: 0067-7050 V05, 2022-02-23.

Using the Vestas reactive power capability, shown in *Figure 5: Vestas V150 4.5 MW reactive power capability*, various levels were calculated and are displayed below in *Table 4: Power factor analysis results*.

Table 4: Power factor analysis results

Breakpoints on reactive capability curve (V = 1.0pu)	IR597 rated output (8 x 4.5 MW WTG units)				Measurements at the HV terminals of the ICIF substation				Meets net 0.95 pf requirement?
	MW	MVAR	MVA	pf	MW	MVAR	MVA	pf	
Maximum Reactive Injection (Point B)	36.00	20.40	41.38	0.870	35.40	11.90	37.35	0.948	Yes
Maxiumum Reactive Absorption (Point C)	36.00	-12.80	38.21	0.942	35.40	-20.60	40.96	0.864	Yes

The Vestas technical bulletin's reactive power capability, shown in Figure 2, shows that the reactive power injection capability is not reduced at full output at nominal voltage (regions A-B). When the wind farm is operating at its max active power nameplate capacity, power factor measured at the ICIF HV terminals is just within limits. If the actual collector circuit differs significantly from the assumed generic collector circuit parameters used, this analysis should be re-evaluated.

IR597 therefore meets NS Power's ±0.95 net power factor requirement at the HV terminals of the ICIF substation based on PSSE simulations using parameters provided by the IC and assumptions as provided in Section 1.2. IR597 is also required to produce/ absorb reactive power at all production levels up to its full rated output.

3.3 Voltage Flicker

NS Power's voltage flicker requirements are:

- $P_{st} \leq 0.25$
- $P_{lt} \leq 0.35$

The voltage flicker calculations use IEC Standard 61300-21 based on test data provided by the IC for the Vestas V150-4.2 MW machines at 50 Hz. A flicker coefficient was selected from the test data measured for an 70° system angle (most conservative values) and maximum active power output (4.2 MW). The voltage flicker Pst and Plt levels are calculated at the POI for various system conditions listed in Table 5.

Table 5: Calculated voltage flicker

System Conditions	Continuous (Pst=Plt)
Maximum Generation	
All transmission facilities in service	0.058
Minimum Generation	
All transmission facilities in service	0.068
L-6025 out of service	0.071

IR597 therefore meets NS Power's required short term and long-term voltage flicker requirements based on the supplied calculated data, with the assumption that the Vestas V150-4.5 MW model does not differ significantly in terms of voltage flicker performance.

The generator must also meet IEEE Standard 519-2014 limiting Total Harmonic Distortion (all frequencies) to no higher than 2.5% with no individual harmonic exceeding 1.5% for the 138 kV voltage level. It is the generating facility's responsibility to ensure that this requirement is met as this SIS cannot make this assessment.

3.4 Steady State Analysis

3.4.1 Base Cases

Base cases used in this study are listed in Table 6: *Base Case Dispatch*. They were selected to reflect conditions under varying amounts of low/high area load vs historic area generation. This approach was chosen because portions of the Western/Valley transmission system would presently experience overloads if the entire area hydro and wind plants were simultaneously operated at maximum capacity under system light load.

Area transmission line ratings are listed in Appendix A: *Transmission line ratings*. One-line diagrams of each base case, in sets of three, are presented in Appendix C: *Base case one-line diagrams*.

Table 6: Base Case Dispatch

Case	NS load	IR597 status	Wind	West/ valley hydro	NS/ NB	ML	CBX	ONI	ONS	Valley imp	West imp	Valley exp	West/ Valley imp	West/ valley load
WIN_01-1	2198	-	486	126	150	-320	825	1029	764	103	114	7	59	504
WIN_01-2	2198	36	522	126	150	-320	789	1018	754	101	83	7	59	504
FAL_01-1	1370	-	486	104	331	-475	584	713	345	-4	36	41	1	312
FAL_01-2	1370	36	522	104	334	-475	584	713	343	-6	5	41	1	312
FAL_02-1	1370	-	466	23	331	-475	609	737	369	61	70	-30	72	312
FAL_02-2	1370	36	502	23	334	-475	609	737	367	59	39	-30	72	312
SLL_01-1	710	-	367	6	332	-475	413	415	82	0	21	9	17	164
SLL_01-2	710	36	403	6	334	-475	413	415	79	-3	-10	9	17	164
SUM_01-1	1570	-	486	126	331	-475	704	819	431	21	59	32	16	353
SUM_01-2	1570	36	522	126	334	-475	669	785	395	19	23	32	16	353
SUM_02-1	1570	-	486	126	-296	-330	228	218	459	21	59	33	16	353
SUM_02-2	1570	36	522	126	-297	-330	228	218	461	19	23	33	16	353

Note 1: All values are in MW.
Note 2: CBX (Cape Breton Export) and ONI (Onslow Import) are Interconnection Reliability Operating Limit (IROL) defined interfaces.
Note 3: Wind refers to only transmission connected wind.

Regarding the case dispatches:

- WIN_01-x represents peak load, with relatively high East-West transfers. Generation dispatched is assumed to be typical for peak load, with high load in the Valley area.

- FAL_01/02-x represent a shoulder season load (with summer ratings in effect) with high wind and varying west/valley hydro dispatch. This represents typical spring hydro run-off conditions.
- SUM_01-x represents summer peak load and maximum generation in the Valley area. Local generation is managed to ensure transmission limits are maintained.
- SUM_02-x represents the NS/NB import limit, presently 27% of net in-province load, to a maximum 300 MW. This case has three equivalent thermal units online, running near minimum load, plus 330 MW import from NL. It represents a low inertia scenario on the NS system and is used to test the performance of the Underfrequency Load Shedding (UFLS) system during contingencies which isolate NS from the interconnected power system (e.g. loss of L-8001).
- SLL_01-x represents spring light load, which is typically the lightest loading period experienced by the NS system. Summer ratings are in effect, and small hydro units are dispatched at a minimum.

3.4.2 Contingencies

The steady state power flow analysis includes the contingencies listed in Table 7.

Table 7: Steady State Contingencies

ID	Element	Type	Location	ID	Element	Type	Location
1	101S_L-7011	Line fault	101S-Woodbine	111	50W_L-6020	Line fault	50W-Milton
2	101S_L-7012	Line fault	101S-Woodbine	112	50W_L-6024	Line fault	50W-Milton
3	101S_L-7015	Line fault	101S-Woodbine	113	51V_51V-B51	Bus fault	51V-Tremont
4	101S_L-8004_G0	Line fault	101S-Woodbine	114	51V_51V-B52	Bus fault	51V-Tremont
5	101S_ML-BIPOLE	HVDC line fault	101S-Woodbine	115	51V_51V-B61	Bus fault	51V-Tremont
6	101S_ML-POLE1	HVDC line fault	101S-Woodbine	116	51V_51V-T61	Transformer fault	51V-Tremont
7	101S_ML-POLE2	HVDC line fault	101S-Woodbine	117	51V_L-5025	Line fault	51V-Tremont
8	101S-701	Breaker fail	101S-Woodbine	118	5S_L-6516	Line fault	5S-Glen Tosh
9	101S-702	Breaker fail	101S-Woodbine	119	5S_L-6537	Line fault	5S-Glen Tosh
10	101S-703	Breaker fail	101S-Woodbine	120	5S_L-6538	Line fault	5S-Glen Tosh
11	101S-704	Breaker fail	101S-Woodbine	121	5S-606	Breaker fail	5S-Glen Tosh
12	101S-705	Breaker fail	101S-Woodbine	122	5S-607	Breaker fail	5S-Glen Tosh
13	101S-706	Breaker fail	101S-Woodbine	123	67N_L-7001	Line fault	67N-Onslow
14	101S-711	Breaker fail	101S-Woodbine	124	67N_L-7002	Line fault	67N-Onslow
15	101S-712	Breaker fail	101S-Woodbine	125	67N_L-7019	Line fault	67N-Onslow
16	101S-713	Breaker fail	101S-Woodbine	126	67N_L-8001_G0	Line fault	67N-Onslow
17	101S-811	Breaker fail	101S-Woodbine	127	67N_L-8002	Line fault	67N-Onslow
18	101S-812_G0	Breaker fail	101S-Woodbine	128	67N-701	Breaker fail	67N-Onslow
19	101S-813_G0	Breaker fail	101S-Woodbine	129	67N-702	Breaker fail	67N-Onslow
20	101S-814	Breaker fail	101S-Woodbine	130	67N-703	Breaker fail	67N-Onslow
21	101S-816	Breaker fail	101S-Woodbine	131	67N-704	Breaker fail	67N-Onslow

22	101S-T81	Transformer fault	101S-Woodbine	132	67N-705	Breaker fail	67N-Onslow
23	101S-T82	Transformer fault	101S-Woodbine	133	67N-706	Breaker fail	67N-Onslow
24	103H_L-6008	Line fault	103H-Lakeside	134	67N-710	Breaker fail	67N-Onslow
25	103H_L-6033	Line fault	103H-Lakeside	135	67N-711_G0	Breaker fail	67N-Onslow
26	103H_L-6038	Line fault	103H-Lakeside	136	67N-712	Breaker fail	67N-Onslow
27	103H-600	Breaker fail	103H-Lakeside	137	67N-713	Breaker fail	67N-Onslow
28	103H-608	Breaker fail	103H-Lakeside	138	67N-811_G0	Breaker fail	67N-Onslow
29	103H-681	Breaker fail	103H-Lakeside	139	67N-813	Breaker fail	67N-Onslow
30	103H-881	Breaker fail	103H-Lakeside	140	67N-814_G0	Breaker fail	67N-Onslow
31	103H-B61	Bus fault	103H-Lakeside	141	67N-T71	Transformer fault	67N-Onslow
32	103H-B62	Bus fault	103H-Lakeside	142	67N-T81	Transformer fault	67N-Onslow
33	103H-T61	Transformer fault	103H-Lakeside	143	67N-T82	Transformer fault	67N-Onslow
34	103H-T63	Transformer fault	103H-Lakeside	144	79N_L-6507	Line fault	79N-Hopewell
35	103H-T81	Transformer fault	103H-Lakeside	145	79N_L-6508	Line fault	79N-Hopewell
36	104H-600	Breaker fail	104H-Kempt Road	146	79N_L-8003_G0	Line fault	79N-Hopewell
37	104W-G1	Generator trip	104W-Brooklyn	147	79N-T81_G0	Transformer fault	79N-Hopewell
38	110W-B61	Bus fault	110W-South Canoe	148	85S_L-6545	Line fault	85S-Wreck Cove
39	110W-T62	Transformer fault	110W-South Canoe	149	88S_L-7014	Line fault	88S-Lingan
40	11V_11V-B51	Bus fault	11V-Paradise	150	88S_L-7021	Line fault	88S-Lingan
41	120H_L-6005	Line fault	120H-Brushy Hill	151	88S_L-7022	Line fault	88S-Lingan
42	120H_L-6010	Line fault	120H-Brushy Hill	152	88S-710	Breaker fail	88S-Lingan
43	120H_L-6011	Line fault	120H-Brushy Hill	153	88S-711	Breaker fail	88S-Lingan
44	120H_L-6016	Line fault	120H-Brushy Hill	154	88S-713	Breaker fail	88S-Lingan
45	120H_L-6051	Line fault	120H-Brushy Hill	155	88S-714	Breaker fail	88S-Lingan
46	120H_L-7008	Line fault	120H-Brushy Hill	156	88S-715	Breaker fail	88S-Lingan
47	120H_L-7009	Line fault	120H-Brushy Hill	157	88S-720	Breaker fail	88S-Lingan
48	120H-621	Breaker fail	120H-Brushy Hill	158	88S-721	Breaker fail	88S-Lingan
49	120H-622	Breaker fail	120H-Brushy Hill	159	88S-722	Breaker fail	88S-Lingan
50	120H-623	Breaker fail	120H-Brushy Hill	160	88S-723_G0	Breaker fail	88S-Lingan
51	120H-624	Breaker fail	120H-Brushy Hill	161	88S-G2	Generator trip	88S-Lingan
52	120H-626	Breaker fail	120H-Brushy Hill	162	88S-G3	Generator trip	88S-Lingan
53	120H-627	Breaker fail	120H-Brushy Hill	163	88S-G4	Generator trip	88S-Lingan
54	120H-628	Breaker fail	120H-Brushy Hill	164	88S-T71	Transformer fault	88S-Lingan
55	120H-629	Breaker fail	120H-Brushy Hill	165	88S-T72	Transformer fault	88S-Lingan
56	120H-710	Breaker fail	120H-Brushy Hill	166	89S-G1	Generator trip	89S-Point Aconi
57	120H-711	Breaker fail	120H-Brushy Hill	167	90H_L-6002	Line fault	90H-Sackville
58	120H-712	Breaker fail	120H-Brushy Hill	168	90H_L-6003	Line fault	90H-Sackville
59	120H-713	Breaker fail	120H-Brushy Hill	169	90H_L-6004	Line fault	90H-Sackville
60	120H-714	Breaker fail	120H-Brushy Hill	170	90H_L-6009	Line fault	90H-Sackville

61	120H-715	Breaker fail	120H-Brushy Hill	171	90H-605	Breaker fail	90H-Sackville
62	120H-716	Breaker fail	120H-Brushy Hill	172	90H-611	Breaker fail	90H-Sackville
63	120H-720	Breaker fail	120H-Brushy Hill	173	91H_L-5012	Line fault	91H-Tufts Cove
64	120H-SVC	Reactive device trip	120H-Brushy Hill	174	91H_L-5041	Line fault	91H-Tufts Cove
65	120H-T71	Transformer fault	120H-Brushy Hill	175	91H_L-5049	Line fault	91H-Tufts Cove
66	120H-T72	Transformer fault	120H-Brushy Hill	176	91H-511	Breaker fail	91H-Tufts Cove
67	13V_13V-B51	Bus fault	13V-Gulch Hydro	177	91H-516	Breaker fail	91H-Tufts Cove
68	13V_L-5026	Line fault	13V-Gulch Hydro	178	91H-521	Breaker fail	91H-Tufts Cove
69	13V_L-5531	Line fault	13V-Gulch Hydro	179	91H-523	Breaker fail	91H-Tufts Cove
70	13V_L-5532	Line fault	13V-Gulch Hydro	180	91H-G3	Generator trip	91H-Tufts Cove
71	1C-G2	Generator trip	1C-Point Tupper	181	91H-G4	Generator trip	91H-Tufts Cove
72	1N_L-6001	Line fault	1N-Onslow	182	91H-G5	Generator trip	91H-Tufts Cove
73	1N_L-6503	Line fault	1N-Onslow	183	91H-G6	Generator trip	91H-Tufts Cove
74	1N_L-6513	Line fault	1N-Onslow	184	91H-T11	Transformer fault	91H-Tufts Cove
75	1N-600	Breaker fail	1N-Onslow	185	91H-T62	Transformer fault	91H-Tufts Cove
76	1N-601	Breaker fail	1N-Onslow	186	91N-701	Breaker fail	91N-Dalhousie Wind
77	1N-613	Breaker fail	1N-Onslow	187	91N-702	Breaker fail	91N-Dalhousie Wind
78	1N-B61	Bus fault	1N-Onslow	188	91N-703	Breaker fail	91N-Dalhousie Wind
79	1N-B62	Bus fault	1N-Onslow	189	91N-B71	Bus fault	91N-Dalhousie Wind
80	1N-C61	Reactive device trip	1N-Onslow	190	99W_99W-B61	Bus fault	99W-Bridgewater
81	1N-T1	Transformer fault	1N-Onslow	191	99W_99W-B62	Bus fault	99W-Bridgewater
82	1N-T4	Transformer fault	1N-Onslow	192	99W_99W-T71	Transformer fault	99W-Bridgewater
83	1N-T65	Transformer fault	1N-Onslow	193	99W_99W-T72	Transformer fault	99W-Bridgewater
84	30W_30W-B51	Bus fault	30W-Souriquois	194	99W_L-6025	Line fault	99W-Bridgewater
85	30W_30W-T62	Bus fault	30W-Souriquois	195	99W-708	Breaker fail	99W-Bridgewater
86	3C_L-7003	Line fault	3C-Port Hastings	196	99W-709	Breaker fail	99W-Bridgewater
87	3C_L-7004	Line fault	3C-Port Hastings	197	99W-T71	Transformer fault	99W-Bridgewater
88	3C_L-7005_G0	Line fault	3C-Port Hastings	198	99W-T72	Transformer fault	99W-Bridgewater
89	3C-710_G0	Breaker fail	3C-Port Hastings	199	9W_9W-B53	Bus fault	9W-Tusket Hydro
90	3C-711	Breaker fail	3C-Port Hastings	200	9W_9W-T2	Transformer fault	9W-Tusket Hydro
91	3C-712	Breaker fail	3C-Port Hastings	201	9W_L-5535	Line fault	9W-Tusket Hydro
92	3C-713	Breaker fail	3C-Port Hastings	202	DCT_L-5039][L-6033	Double cct tower	Bayers Lake
93	3C-714	Breaker fail	3C-Port Hastings	203	DCT_L-6005][L-6016	Double cct tower	Sackville
94	3C-715	Breaker fail	3C-Port Hastings	204	DCT_L-6010][L-6005	Double cct tower	Sackville
95	3C-716	Breaker fail	3C-Port Hastings	205	DCT_L-6011][L-6010	Double cct tower	Sackville
96	3C-T71	Transformer fault	3C-Port Hastings	206	DCT_L-6033][L-6035	Double cct tower	Halifax
97	3C-T72	Transformer fault	3C-Port Hastings	207	DCT_L-6507][L-6508	Double cct tower	Trenton

98	3S_L-6539	Line fault	3S-Gannon Rd	208	DCT_L-7003][L-7004_G0	Double cct tower	Canso Causeway
99	43V_43V-B61	Bus fault	43V-Canaan Rd	209	DCT_L-7008][L-7009	Double cct tower	Bridgewater
100	43V_43V-B62	Bus fault	43V-Canaan Rd	210	DCT_L-7009][L-8002	Double cct tower	Sackville
101	43V_L-6012	Line fault	43V-Canaan Rd	211	DCT_L-7021][L-6534	Double cct tower	Lingan / VJ
102	43V_L-6013	Line fault	43V-Canaan Rd	212	IR597	Generator trip	50W-Milton
103	43V_L-6054	Line fault	43V-Canaan Rd	213	MEMRAMCOOK_L1159	Line fault	New Brunswick
104	48C-G1	Generator trip	48C-PHP	214	MEMRAMCOOK_L1160	Line fault	New Brunswick
105	50N-G5	Generator trip	50N-Trenton	215	MEMRAMCOOK_ME3-1	Breaker fail	New Brunswick
106	50N-G6	Generator trip	50N-Trenton	216	SALISBURY_L3004	Line fault	New Brunswick
107	50W_50W-B2	Bus fault	50W-Milton	217	SALISBURY_L3006	Line fault	New Brunswick
108	50W_50W-B3	Bus fault	50W-Milton	218	SALISBURY_L3013	Line fault	New Brunswick
109	50W_50W-B4	Bus fault	50W-Milton	219	SALISBURY_SA3-2	Breaker fail	New Brunswick
110	50W_L-5541	Line fault	50W-Milton				

3.4.3 Evaluation

The steady state contingencies evaluated in this study demonstrate IR597 does not require Network Upgrades beyond the POI to operate at its full capacity of 36 MW under NRIS.

IR597 has little impact on transmission in the Western region due to its connection into the 138 kV bus at 50W-Milton. Single line diagrams showing the load flows of each of the bases cases are presented in Appendix C: *Base case one-line diagrams*. Results of the steady state analysis are presented in Appendix D: *Steady-state analysis results*. Notes are provided to explain observed issues, which are also summarized below, in Table 8. These contingencies around the 50W-Milton substation resulted in pre-existing undervoltage conditions in the 69 kV system between 9W-Tusket and 30W-Souriquois, however, the presence of IR597 did not worsen their severity.

Table 8: Steady State Violations

ID	Contingency	Case	Post-Contingency	Violation Magnitude
108	50W_50W-B3	FAL_01, SUM_01, WIN_01	30W-Souriquous UV	V(pu)=0.8960
109	50W_50W-B4	FAL_01, WIN_01	9W-Tusket: UV	V(pu)=0.8885
112	50W_L-6024	FAL_01, SUM_01, WIN_01	22W-Barrington UV	V(pu)=0.8781
199	9W_9W-B53	WIN_01	10W-Tusket GT HV	V(pu)=1.1243

3.5 Stability Analysis

System design criteria requires the system to be stable and well damped in all modes of oscillations. No cascade tripping shall occur apart from designed breaker back-up protection operation.

3.5.1 Base Cases

All steady-state cases were studied for contingencies that provide the best measure of system reliability. The parameters of these base cases are repeated below in Table 9.

Table 9: Stability Base Cases

Case	NS load	IR597 status	Wind	West/ Valley Hydro	NS/ NB	ML	CBX	ONI	ONS
WIN_01-1	2198	-	486	126	150	-320	825	1029	764
WIN_01-2	2198	36	522	126	150	-320	789	1018	754
FAL_01-1	1370	-	486	104	331	-475	584	713	345
FAL_01-2	1370	36	522	104	334	-475	584	713	343
FAL_02-1	1370	-	466	23	331	-475	609	737	369
FAL_02-2	1370	36	502	23	334	-475	609	737	367
SLL_01-1	710	-	367	6	332	-475	413	415	82
SLL_01-2	710	36	403	6	334	-475	413	415	79
SUM_01-1	1570	-	486	126	331	-475	704	819	431
SUM_01-2	1570	36	522	126	334	-475	669	785	395
SUM_02-1	1570	-	486	126	-296	-330	228	218	459
SUM_02-2	1570	36	522	126	-297	-330	228	218	461

3.5.2 Contingencies

The contingencies tested for this study are listed in Table 10.

Table 10: Stability Contingency List

ID	Contingency	Fault	Tripped Elements	Notes
1	101S BBU 101S-812	breaker fail @ 101S	L8004: 101S/79N ML Pole 2	G5/G6 SPS
2	101S L8004 3PH Fault	3ph line fault @ 101S	101S/79N	G5/G6 SPS
3	101S MLBIPOLE 1LG Fault	DC line fault @ 101S	ML Pole 1 & 2	
4	103H BBU 103H-608	breaker fail @ 103H	L6008:103H/90H L6016:103H/137H L6038:103H/129H 67N-T61	
5	103H BBU 103H-681	breaker fail @ 103H	L8002:103H/67N 103H-T81 103H-T63 L6033:103H/2H/1H	
6	103H BBU 103H-881	breaker fail @ 103H	L8002:103H/67N 103H-T81	
7	103H BKR 103H-600 1P	breaker fail @ 103H	L6008:103H/90H L6016:103H/137H/120H L6038:103H/129H L5039:103H/34H/20H	
8	103H L6008 3PH Fault	3ph line fault @ 103H	L6008:103H/90H	
9	103H L6016 3PH Fault	3ph line fault @ 103H	L6016:103H/137H/120H	
10	103H L6033 3PH Fault	3ph line fault @ 103H	L6033:103H/2H/1H	
11	103H L8002 3PH Fault	3ph line fault @ 103H	L8002:103H/67N	

12	11V-B51 3PH Fault	3ph bus fault @ 11V	L5025:11V/10V/51V L5026:11V/70V/13V 11V-G1	98V AAS
13	11V L5025 3PH Fault	3ph line fault @ 11V	L5025:11V/10V/51V	98V AAS
14	11V L5026 3PH Fault	3ph line fault @ 11V	L5026:11V/70V/13V	98V AAS
15	120H BBU 120H-622	breaker fail @ 120H	L6005: 120H/131H L6016: 120H/137H	
16	120H BBU 120H-710	breaker fail @ 120H	120H-T71 L7018: 120H/67N	
17	120H BBU 120H-715	breaker fail @ 120H	L7001:120H/67N L7008:120H/99W	
18	120H L6005 3PH Fault	3ph line fault @ 120H	L6005: 120H/131H	
19	120H L6010 3PH Fault	3ph line fault @ 120H	L6010: 120H/90H	
20	120H L6011 3PH Fault	3ph line fault @ 120H	L6011: 120H/17V	
21	120H L6016 3PH Fault	3ph line fault @ 120H	L6016: 120H/137H	
22	120H L7008 3PH Fault	3ph line fault @ 120H	L7008: 120H/99W	
23	120H L7018 3PH Fault	3ph line fault @ 120H	L7018: 120H/67N	
24	13V-B51 3PH Fault	3ph bus fault @ 13V	L5531:13V/15V L5533:13V/77V L5532:13V/14V/3W L5026:13V/74V/11V 13V-G1	
25	13V L5026 3PH Fault	3ph line fault @ 13V	L5026:13V/74V/11V	
26	13V L5531 3PH Fault	3ph line fault @ 13V	L5531:13V/15V	
27	13V L5532 3PH Fault	3ph line fault @ 13V	L5532:13V/14V/3W	
28	15V-B51 3PH Fault	3ph bus fault @ 15V	L5538:15V/16V L5531:15V/13V L5050:15V/91V L5535:15V/34W/9W 15V-G1/2	
29	15V L5535 3PH Fault	3ph line fault @ 15V	L5535:15V/34W/9W	
30	17V BBU 17V-612	breaker fail @ 17V	L6012:17V/43V L6051:17V/120H 17V-T2	
31	1N BBU 1N-601	breaker fail @ 1N	L6001:1N/82V/132H 67N-T71 1N-T4 1N-C61	
32	1N BBU 1N-613	breaker fail @ 1N	L6613:1N/81N/74N L6503:1N/49N/51N 1N-T65	
33	1N BKR 1N-600 1P	breaker fail @ 1N	L6527:1N/67N L6613:1N/81N/74N L6503:1N/49N/51N/50N L6001:1N/82V/132H 1N-T65 1N-T1 1N-T4	Isolates 1N
34	1N L6001 3PH Fault	3ph line fault @ 1N	L6001:1N/82V/132H	
35	1N L6503 3PH Fault	3ph line fault @ 1N	L6503:1N/49N/51N/50N	
36	1N L6613 3PH Fault	3ph line fault @ 1N	L6613:1N/81N/74N	

37	3C L7005 3PH Fault	3ph line fault @ 3C	L7005: 67N/3C	G3 SPS
38	410N L3006 3PH Fault	3ph line fault @ 410N	410N/4592-Salisbury	Export SPS Import SPS
39	43V BBU 43V-612	breaker fail @ 43V	L6012:43V/17V L6013:43V/51V 43V-T61 43V-C61	
40	43V-B61 3PH Fault	3ph bus fault @ 43V	L6012:43V/17V L6013:43V/51V 43V-T61	
41	43V-B62 3PH Fault	3ph bus fault @ 43V	L6015:43V/51V L6051:43V/99V L6054:43V/101V 43V-T62	
42	43V L6012 3PH Fault	3ph line fault @ 43V	L6012:43V/17V	
43	50W-B2 3PH Fault	3ph bus fault @ 50W	L5549:50W/48W L5530:50W/46W/30W L5540A:50W/6W L5540B:50W/5W L5541:50W/4W/3W 50W-T1	
44	50W-B3 3PH Fault	3ph bus fault @ 50W	50W-T1 L6020: 50W/30W/9W L6531: 50W/99W L6047: 60W/101W	
45	50W-B4 3PH Fault	3ph bus fault @ 50W	L6024:50W/9W L6006:50W/99W L6048:50W/104W/101W L6025:50W/99W	
46	51V-B51 3PH Fault	3ph bus fault @ 51V	L5025:51V/10V/11V 51V-T61 51V-T51	98V AAS
47	51V L5025 3PH Fault	3ph line fault @ 51V	L5025:51V/10V/11V	98V AAS
48	51V L5025 3PH Fault SPS	3ph line fault @ 51V	L5025:51V/10V/11V	98V AAS
49	67N BBU 67N-711	breaker fail @ 67N	L7005:67N/3C 67N-T82	
50	67N BBU 67N-712	breaker fail @ 67N	L7018:67N/120H L7005:67N/3C	
51	67N BBU 67N-713	breaker fail @ 67N	L7018:67N/120H 67N-T81	
52	67N BBU 67N-811	breaker fail @ 67N	L8003:67N/79N 67N-T82	G5/G6 SPS
53	67N BBU 67N-811 T82	breaker fail @ 67N	67N-T82 L8003:67N/79N	G5/G6 SPS
54	67N BBU 67N-813	breaker fail @ 67N	L8002:67N/103H 67N-T81	
55	67N BBU 67N-814	breaker fail @ 67N	L8001:67N/410N 67N-T81	Export SPS: G5/G6
56	67N BKR 67N-814 No Fault	breaker fail @ 67N	L8001:67N/410N 67N-T81	Import SPS
57	67N L7018 3PH Fault	3ph line fault @ 67N	L7018:67N/120H	
58	67N L8001 3PH Fault	3ph line fault @ 67N	L8001:67N/410N	Export SPS: G5/G6 Import SPS
59	67N L8002 3PH Fault	3ph line fault @ 67N	L8002:67N/103H	

60	67N L8003 3PH Fault	3ph line fault @ 67N	L8003:67N/79N	G5/G6 SPS
61	79N L8003 3PH Fault	3ph line fault @ 79N	L8003:79N/67N	G5/G6 SPS
62	79N L8004 3PH Fault	3ph line fault @ 79N	L8004:79N/101S	G5/G6 SPS
63	79N T81 HV Fault	3ph xfmr fault @ 79N	L8003:79N/67N L8004:79N/101S L6508:79N/50N L6507:79N/50N	G5/G6 SPS
64	90H L6008 3PH Fault	3ph line fault @ 90H	L6008:90H/103H	
65	91N BBU 91N-701	breaker fail @ 91N	L7004: 3C/91N L7019: 91N/67N 91N WTG	
66	9W-B53 3PH Fault	3ph bus fault @ 9W	L6024:9W/50W L5534:9W/16W L5535:9W/92W 9W-T63	
67	9W L5535 3PH Fault	3ph line fault @ 9W	L5535:9W/92W	
68	9W L6021 3PH Fault	3ph line fault @ 9W	L6021:50W/9W	
69	9W L6024 3PH Fault	3ph line fault @ 9W	L6024:9W/50W	
70	DCT 6005][6010	DCT fault	L6005: 120H/131H L6010:120H/90H	
71	DCT 6005][6016	DCT fault	L6005: 120H/131H L6016:120H/137H	
72	DCT 6010][6011	DCT fault	L6010: 120H/90H L6011: 120H/17V	
73	DCT 6033][6035	DCT fault	L6033: 103H/2H/1H L6035: 1H/2H/104H	
74	DCT 7003][7004	DCT fault	L7003: 3C/67N L7004: 3C/91N	G3 SPS
75	DCT 7008][7009	DCT fault	L7008: 120H/99W L7009: 120H/99W	
76	DCT 7009][8002	DCT fault	L7009: 120H/99W L8002: 103H/67N	

3.5.3 Evaluation

PSSE generated output plots for each contingency, with IR597 out of service and in service, are presented in Appendices H through S. All relevant contingencies were found to be stable and well-damped. Notes are provided in the Appendices where further explanation is necessary.

3.6 NPCC-BPS / NERC-BES

At the time of this study, the proposed POI at 50W-Milton is neither categorized as NPCC[2] BPS *(Bulk Power System)* or NERC[3] BES *(Bulk Electric System)*.

3.6.1 NPCC-BPS

The BPS testing for the POI bus of IR597 was performed in accordance with the A-10 methodology described in Section 2.3.7.1.

The stability test was performed by placing a 3-phase fault at the high voltage terminals at the POI, with all local protection out of service. Appendix E: *NPCC-BPS determination results* demonstrates IR597 does not have adverse impact outside the local area. The stability test was performed using both the WIN_01-2 and the SLL_01-2 cases, representing maximum and minimum expected load levels.

The steady state test was conducted by dispatching the new facility at full output, then disconnecting it, along with all elements which tripped during the stability test. Post-contingency results reveal no voltage violations or thermal overloads outside the local area, confirming the transmission facilities associated with IR597 are not classified as NPCC BPS.

Note that NPCC's *A-10 Classification of Bulk Power System Elements* requires NS Power to perform a periodic comprehensive re-assessment at least once every five years. It is possible for this site's BPS status to change, depending on future system configuration changes, requiring the IC to adapt to NPCC reliability requirements accordingly.

3.6.2 NERC-BES

IR597 is not categorized as NERC BES, since it does not meet any of the four inclusion criteria:

- I1: The ICIF transformer's secondary terminal is <100kV.
- I2: The gross plant/facility aggregate nameplate rating is <75MVA.
- I3: The POI, 50W-Milton substation, is not on a Black Start path.
- I4: It is a radial system that emanates from a single point of connection of ≥100kV and only includes generation resources <75MVA.

3.7 Underfrequency Operation

IR597's low frequency ridethrough performance was tested by simulating a fault on L-8001 under high import conditions. The case selected for dynamic simulation was based on Summer Peak, with 300 MW import into Nova Scotia (SUM_02-2).

[2] Northeastern Power Coordination Council.
[3] North American Electric Reliability Corporation.

IR597 remains stable and online as required. Simulation indicates that NS Power's UFLS does not activate to stabilize system frequency. The simulation results are shown in Figure 6 and Figure 7, as well as Appendix F: *Underfrequency operation.*

Note that values are plotted on 100 MVA system base, so IR597 at 0.36 pu power represents full output of the generators (rather than 36% output).

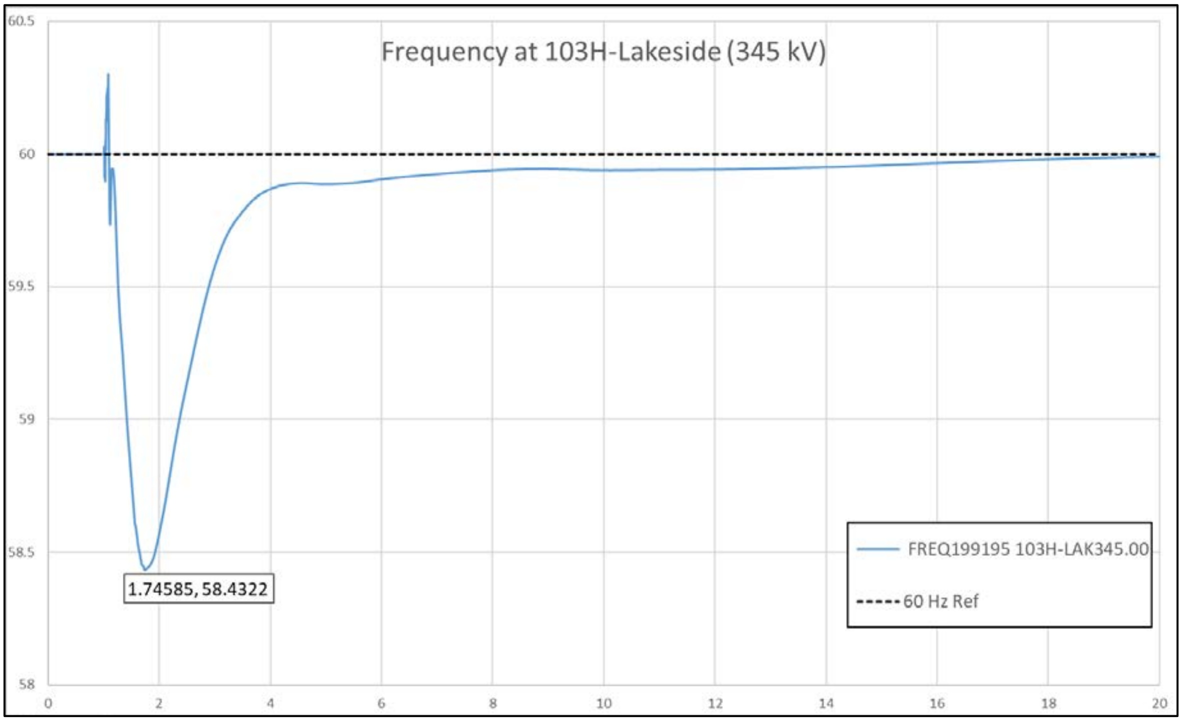


Figure 6: Underfrequency Performance (freq. at 103H-Lakeside)

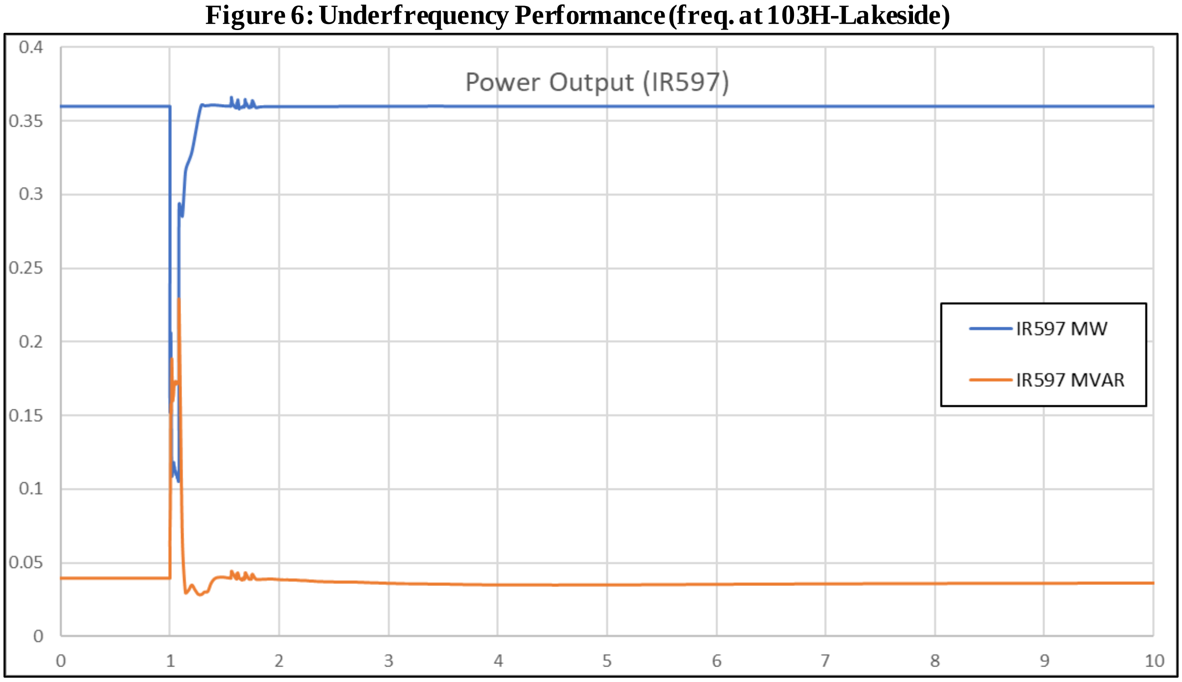


Figure 7: Underfrequency Performance (IR597 machine output)

3.8 Voltage Ridethrough

A 3-phase fault for 9 cycles, simulating a Transmission System fault, was applied to IR597's 138kV and 34.5kV buses to test the WTG facility's Low Voltage Ridethrough (LVRT) capability.

The stability plot in Figure 8 and Figure 9 demonstrate IR597 rides through the fault and stays online in both cases, as required. Results are shown in Appendix G: *Low voltage ridethrough*.

Note that values are plotted on 100 MVA system base, so IR597 at 0.36 pu power represents full output of the generators (rather than 36% output).

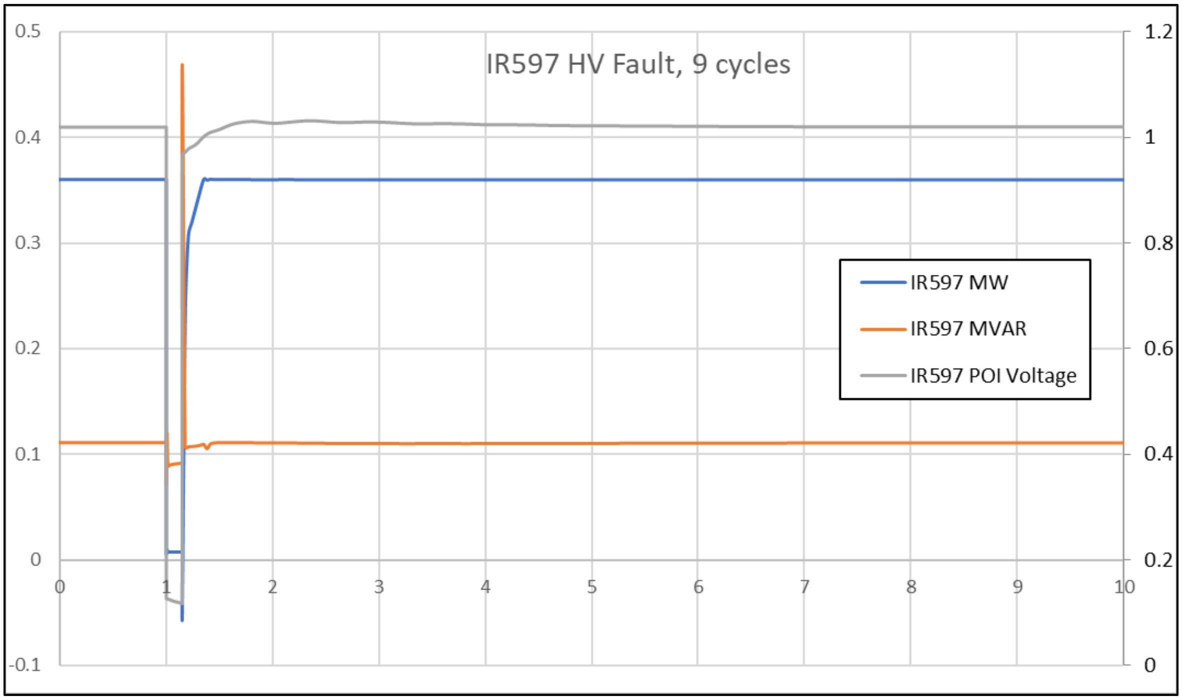


Figure 8: IR597 LVRT Performance (HV fault, 9 cycles)

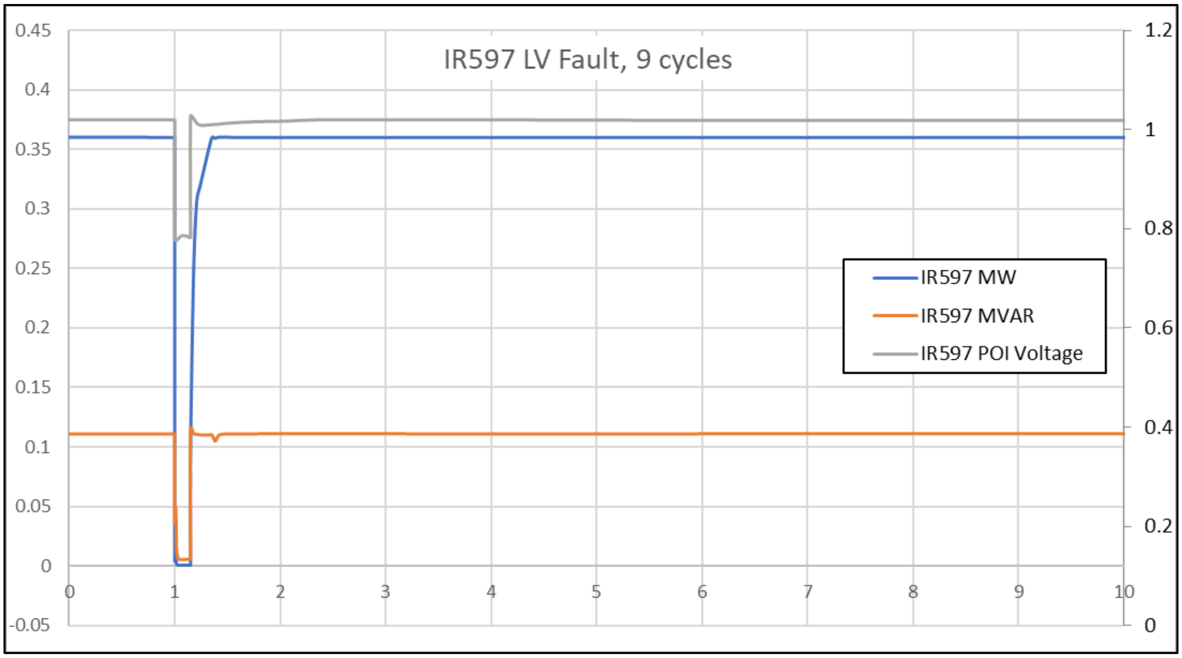


Figure 9: IR597 LVRT Performance (LV fault, 9 cycles)

3.9 Loss Factor

With IR597 in service, the loss factor is calculated as 0.52%. The data and calculation is detailed in Table 6: *IR597 loss factor data* and Equation 1: *IR597 loss factor calculation*, respectively.

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 NS Area Interchange bus. This methodology reflects the load centre in and around 91H-Tufts Cove. A negative loss factor reflects a reduction in system losses.

Table 11: IR597 loss factor data

	Value
IR597 nameplate	36.0
TC3 w/ IR597	107.49
TC3 w/o IR597	143.30
Delta	0.19
2023 loss factor	0.52%

Equation 1: IR597 loss factor calculation

$$loss\ factor = \frac{(IR597_{nameplate} + TC3_{w/\ IR597}) - TC3_{w/o\ IR597}}{IR597_{nameplate}} = 0.52\%$$

4.0 Requirements

4.1 Upgrades & Modifications

The cost estimate includes the additions/modifications to the NS Power system only. The cost of the IC's substation and Generating Facility are not included. All costs of the associated facilities required at the IC's substation and Generating Facility are in addition to the estimate provided in Table 12.

The following facilities are required to interconnect IR597 to the NSPI system via the 138 kV bus at 50W-Milton as NRIS:

1) **Network upgrades:**
    a) No required network upgrades.
2) **Transmission Provider's Interconnection Facilities (TPIF):**
    a) A 138 kV breaker and associated switches, substation modifications, and P&C modifications for the 50W-Milton 138 kV bus.
    b) Construct a 138 kV transmission line, with OHGW *(Overhead Ground Wire)* & OPGW *(Optical Ground Wire)*, approximately 5.3 km long, built to NSPI standards from the 50W-Milton 138 kV bus to the IR597 substation.
    c) Control and communications between the ICIF and the NSPI SCADA and protection system. Communication protocols must be compatible with existing SCADA equipment and any other existing monitoring systems. Requirements for real time control, communication, and tele-protection will be defined in the Facility Study.
3) **Interconnection Customer's Interconnection Facilities (ICIF):**
    a) Centralized controls for voltage setpoint control for the low side of the ICIF transformer. Fast acting control is required and will include a curtailment scheme, which will limit/reduce total output from the facility, upon receipt of a telemetered signal from NSPI's SCADA system.
    b) NSPI to have supervisory and control of this facility, via the centralized controller. This will permit the NSPI System Operator to raise/lower the voltage setpoint, change the status of reactive power controls, change the real/reactive power remotely.
    c) When curtailed, the facility shall offer over-frequency and under-frequency control with ±0.2 Hz deadband and 4% droop characteristic. The active power controls shall also react to continuous control signals from the NSPI SCADA system's Automatic Generation Control (AGC) system to control tie-line fluctuations as required.

d) The facility shall support short-duration frequency deviations by providing inertia response equivalent to a Synchronous Generator with an inertia factor (H) of at least 3.0 MW-s/MVA for a period of at least 10 seconds.

e) Voltage ridethrough capability as described in the NS Power TSIR.

f) Frequency ridethrough capability in accordance with the NS Power TSIR. The facility shall have the capability of riding through a rate of change of frequency of 4 Hz/s.

g) Operation at ambient temperatures as low as -30ºC. The IC shall also provide icing models and conduct icing studies for their facility.

4.2 Cost Estimate

The high level, non-binding, present day cost estimate, excluding HST, for the IR597's Network Resource Interconnection Service is shown in Table 12: *NRIS cost estimate*. This estimate assumes there is adequate space for new equipment and modifications.

Table 12: NRIS cost estimate

Item	Network Upgrades	Estimate
I	None	$ -
	Sub-total	**$ -**

Item	Transmission Provider's Interconnection Facilities	Estimate
I	Substation primary equipment, P&C, at 50W-Milton (including breaker, 2 switches).	$ 1,000,000
II	Transmission line, with OHGW & OPGW, from 50W-Milton to the PCO (route and right-of-way TBD).	$ 2,650,000
III	Teleprotection and SCADA communications via OPGW from 50W-Milton.	$ 500,000
	Sub-total	**$ 4,150,000**

Determined costs	
Subtotal	$ 4,150,000
Contingency (10%)	$ 415,000
Total of determined cost items	$ 4,565,000

The estimated time to construct the Network Upgrades and Transmission Provider's Interconnection Facilities is 18-24 months after receipt of funds. The Interconnection Facilities Study will provide a more detailed cost estimate.

5.0 Conclusions & Recommendations

5.1 Summary of Technical Analysis

Technical analysis, including short circuit, power factor, voltage flicker, steady state, stability, and protection and control analysis was performed. Both NS Power and NPCC planning criteria were applied.

IR597 currently meets the lagging power factor requirement based on the supplied transformer information and assumed collector circuit impedance. It is just on the threshold, however, and should be re-evaluated when final transformer impedances and collector circuit design are determined.

The facilities associated with IR597 are not designated as NPCC BPS as IR597 does not affect the BPS status of existing facilities. IR597 also does not qualify as NERC BES based on the BES inclusion criteria.

The addition of IR597 was not found to adversely impact the thermal capacity of the NS Power Transmission System. No issues were identified in the steady state or stability analysis that are attributed to the operation of IR597.

It is concluded that the incorporation of the proposed facility into the NS Power transmission at the specified location has no negative impacts on the reliability of the NS Power grid, provided the recommendations outlined in this report are implemented.

5.2 Summary of Expected Facilities

To accommodate the full output of IR597, a new 138 kV node is required at the 50W-Milton substation, plus approximately 5.3 km of new 138kV transmission line between the POI and IC substation. In addition, control and communications infrastructure between the IC substation and the NSPI SCADA and protection system is required.

The total high level estimated cost for Interconnection Costs is $4,565,000. The Interconnection Facilities Study will provide a more detailed cost estimate. The costs of all associated facilities required at the IC's substation and Generating Facility are in addition to this estimate.