System Impact Study Report
Part 1
GIP-IR669-SIS-R1

Generator Interconnection Request 669
100.3 MW Wind Facility
Higgins Mountain, NS

2023-06-30

Control Centre Operations
Nova Scotia Power Inc.

Executive Summary

This System Impact Study report (SIS) presents the results for a 100.3 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 #669 in the NSPI Interconnection Request Queue and will be referred to as IR669 throughout this report. The proposed Commercial Operation Date is 2025/12/31.

The Interconnection Customer (IC) identified the 138 kV transmission line L-6613 (between 1N-Onslow and 74N-Springhill) as the Point Of Interconnection (POI). This wind generation facility will be interconnected to the POI via an approximately 2.75 km long 138 kV transmission line from the Point of Change of Ownership (PCO).

There is one relevant long-term firm Transmission Service Reservation (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 IR669 site. The decreased short circuit levels associated with the TSR411 modifications will require further EMT (Electromagnetic Transient) level analysis to ensure the IR669 site is able to operate effectively.

There are no concerns regarding increased short circuit levels as a result of IR669. The increase in short circuit level is within the capability of associated breakers.

The short circuit level at the Interconnection Facility's (IF) high side bus during minimum generation conditions is 396 MVA. With one transmission element out of service it is reduced to 259 MVA for a calculated minimum Short Circuit Ratio (SCR) of 2.6. These values should be provided to Nordex for design specification consideration. The system short circuit level is expected to decline over time with changes to transmission configuration and generation mix.

IR669 does not meet the lagging 0.95 power factor requirement based on the supplied transformer information and assumed collector circuit impedance. As well, IR669 is unable to provide rated reactive power at the zero-power operating point. Additional dynamic reactive power compensation will therefore be required to inject reactive power to achieve 0.95pu power factor measured at the high side of the ICIF transformer, as well as to provide rated reactive power at the zero-power operating point.

IR669 meets NS Power's required continuous voltage flicker requirements under normal system conditions based on the supplied test data. The continuous voltage flicker emission, Plt, can exceed 0.25 for the minimum generation case with L-6613 between Onslow and IR669 out of service. Should this cause an issue with other NS Power Customers, IR669 would be curtailed for the duration of the contingency event.

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.

It is noted that the two 138-34.5 kV, 30/40/50 MVA ICIF (Interconnection Customers Interconnection Facilities) transformers can be overloaded to 108% under some system conditions. It is recommended that the IC confirm that their transformer ratings are sufficient for these loading conditions.

IR669 was not found to cause issues with the stability of the interconnected system.

An EMT (Electromagnetic Transient) study will also be completed as a Part 2 to this SIS. The Part 2 SIS EMT study will progress in parallel with the next phase of the GIP process (Facilities Study). The outcomes of the Part 2 work will be captured as an addendum to the Part 1 SIS report and may trigger restudy for facilities study work completed at that time.

IR669 is not classified as part of the Bulk Power System according to NPCC and is classified as part of the Bulk Electric System according to NERC.

IR669 was found to comply with Low Voltage Ride-through requirements and Underfrequency Ride-through requirements. It is noted that due to the POI of this facility on the line L-6613, the existing NS Import Monitor Type III RAS will require modification to ensure IR669 is remains connected to the NS electrical island following RAS operation. Additions/modifications to RAS are subject to NPCC approval.

The IR669 loss factor is calculated as 6.9% when accounting for the ICIF losses and 4.3% when ignoring the ICIF losses.

The total high-level cost estimate for interconnecting IR669 to the 138 kV transmission line L-6613 as NRIS is $9,930,000. This includes a 10% contingency. This estimate will be further refined in the Facility (FAC) study and in the Part 2 SIS (EMT modeling).

The estimated time to construct the facilities 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 100.3 MW (originally submitted as 100 MW, then amended to 99 MW, then amended to 100.3 MW), wind generation facility interconnected to the NSPI system as Network Resource Interconnection Service (NRIS).

This project is listed as Interconnection Request #669 (originally #623) in the NSPI Interconnection Request Queue and will be referred to as IR669 throughout this report. The proposed Commercial Operation Date is 2025/12/31.

The Interconnection Customer (IC) identified the 138 kV transmission line L-6613 (between 1N-Onslow and 74N-Springhill) as the Point of Interconnection (POI). This wind generation facility will be interconnected to the POI via a 2.75 km long 138 kV transmission line from the Point of Change of Ownership (PCO). Figure 1 shows the approximate location of the proposed IR669 site.

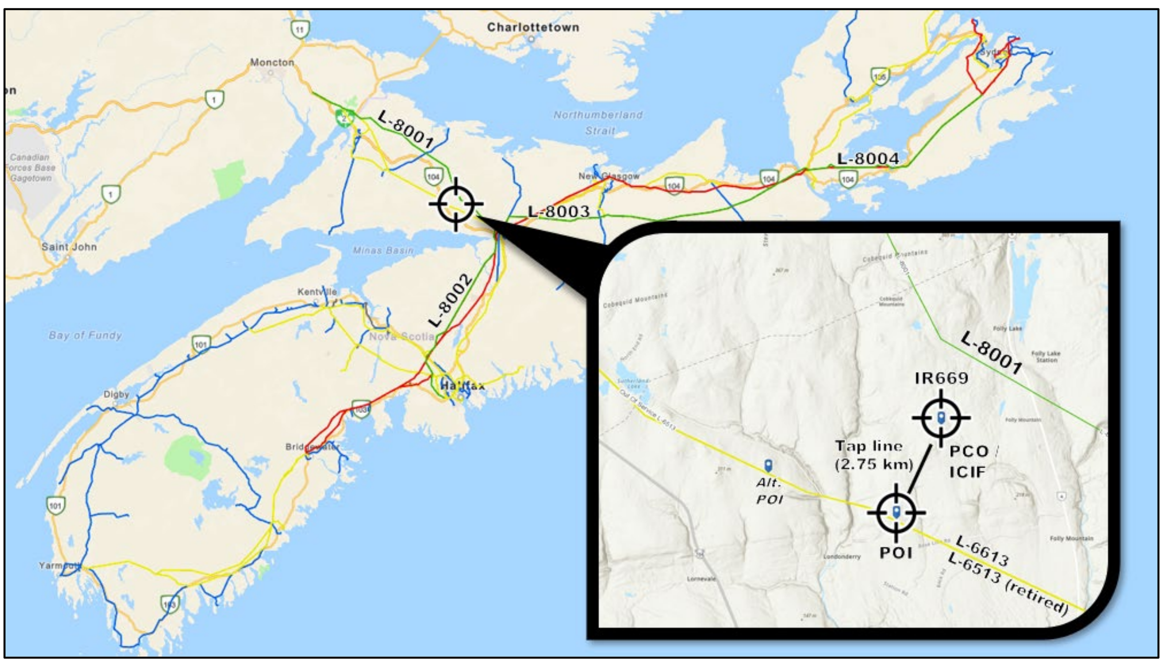


Figure 1: IR669 approximate geographic location

1.1 Scope

This report's objective is to present 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 IR669 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. In addition, an EMT (Electromagnetic Transient) study will also be completed as a Part 2 to this SIS. The Part 2 SIS EMT study will progress in parallel with the next phase of the GIP process (FAC). The outcomes of the Part 2 work will be captured as an addendum to the Part 1 SIS report and may trigger restudy for facilities study work completed at that time. The reason for this is as noted on the NSPI OASIS site:

"Due to the expected increase in inverter-based generation resources in Nova Scotia and the anticipated decrease in synchronous generation related to the requirement to phase-out of coal fired generation by 2030, GIP System Impact Study analyses are being expanded to include Electromagnetic Transient (EMT) Analysis in addition to Load Flow and Dynamic Analysis. To accommodate this change, Interconnection Customers are required to provide the System Operator with the appropriate PSCAD™ models for their generators in addition to the PSS®E generator models required in the Generator Interconnection Procedures. A separate report will be issued for the Electromagnetic Transient Analysis."

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: 2025/12/31.
3. The Interconnection Facility consists of seventeen (17) Nordex N163/5.9 MW wind energy converters, totalling 100.3 MW. These are Type 3 Doubly-Fed Induction Generators (DFIG), split between four collector circuits.

4. The IC identified the 138 kV transmission line L-6613 (between 1N-Onslow and 74N-Springhill) as the Point of Interconnection (POI). The POI is approximately 24 km from the 1N-Onslow substation.
5. The proposed 138 kV transmission line from the POI to the PCO is 2.75 km of 795 ACSR Drake conductor with OPGW.
6. Data was provided by the IC for the substation step-up transformer and generator step-up transformers.
   6.1. The substation step-up transformers were given as two (2) 138 kV - 34.5 kV (Y-d-Y) transformers rated at 30/40/50 MVA each, with de-energized tap changers (DETC) with +/- 5% taps (4 equal steps), a positive sequence impedance of 8.33% and assumed 25.0 X/R ratio. These were modelled as a single equivalent unit for the purpose of this study.
   6.2. The generator step-up transformers were modelled as a single equivalent transformer based off seventeen (17) 34.5 kV (delta) - 0.750 kV (grounded wye), 6.35 MVA transformers, with HV DETC with 4 x 0.5 kV taps, 8.5% positive sequence impedance (estimated given the range of 8%–9%), and 12.0 estimated X/R ratio.
7. A generic collector circuit layout is assumed since an up-to-date 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 1.3: Project Queue Position.
9. It is assumed that IR669 generation meets IEEE Standard 519 for the 138 kV voltage level, limiting total harmonic distortion (all frequencies), to a maximum of 2.5% with no individual harmonic exceeding 1.5%.
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 SIS, except Lingan Unit 2 which is considered to be retired.

As of 2023/01/12, the “Combined T/D Advanced Stage Interconnection Request Queue” (available on NSPI’s OASIS site) is as follows:

Combined T/D Advanced Stage Interconnection Request Queue

Publish Date: *Thursday, January 12, 2023*

Nova Scotia POWER An Emera Company

Queue Order*	IR #	Request Date DD-MMM-YY	County	MW Summer	MW Winter	Interconnection Point Requested	Type	Inservice date DD-MMM-YY	Revised Inservice date	Status	Service Type	IC Identity
1 -T	426	27-Jul-12	Richmond	45	45	47C	Biomass	01-Jan-17	9/1/2018	GIA Executed	NRIS	NSPI
2 -T	516	05-Dec-14	Cumberland	5	5	37N	Tidal	01-Jul-16	5/31/2020	GIA Executed	NRIS	N/A
3 -T	540	28-Jul-16	Hants	14.1	14.1	17V	Wind	01-Jan-18	10/31/2023	GIA Executed	NRIS	N/A
4 -T	542	26-Sep-16	Cumberland	3.78	3.78	37N	Tidal	01-Jan-19	6/30/2025	GIA Executed	NRIS	N/A
5 -D	557	19-Apr-17	Halifax	5.6	5.6	24H	CHP	01-Sep-18		SIS Complete	N/A	N/A
6 -T	517	15-Dec-14	Cumberland	4	4	37N	Tidal	1-Sep-15	10/1/2019	GIA in Progress	NRIS	N/A
7 -D	569	26-Jul-19	Digby	0.6	0.6	509V-302	Tidal	01-Mar-21	2/24/2022	GIA Executed	N/A	N/A
8 -D	566	16-Jan-19	Digby	0.7	0.7	509V-301	Tidal	31-Jul-19	4/30/2022	GIA Executed	N/A	N/A
9 -T	574	27-Aug-20	Hants	58.8	58.8	L-6051	Wind	30-Jun-23	9/30/2025	GIA Executed	NRIS	N/A
10-T	598	13-May-21	Cumberland	2.52	2.52	37N	Tidal	30-Jun-24		GIA Executed	NRIS	N/A
11-D	604	07-Jun-21	Cape Breton	0.45	0.45	11S-303	Solar	30-Mar-23		GIA Executed	N/A	N/A
12-T	597	07-May-21	Queens	36	36	50W	Wind	31-Aug-23		FAC in Progress	NRIS	N/A
13-T	647	06-Oct-21	Cumberland	1.5	1.5	37N	Tidal	31-Dec-23		GIA in Progress	NRIS	N/A
14-D	653	19-Jan-22	Halifax	0.09	0.09	24H-406	Solar	30-Oct-22		GIA Executed	N/A	N/A
15-D	654	16-Feb-22	Halifax	0.125	0.125	127H-413	Solar	20-Sep-22		GIA Executed	N/A	N/A
16-T	656	28-Mar-22	Cumberland	4	4	37N	Tidal	31-Dec-22		GIA in Progress	NRIS	N/A
17-T	672	05-Aug-22	Hants	33.4	33.4	L-5060	Wind	02-Dec-24		SIS in Progress	NRIS	N/A
18-T	664	26-Jul-22	Lunenburg	50	50	99W	Battery	15-Dec-23		SIS in Progress	NRIS	NSPI
19-T	662	26-Jul-22	Halifax	50	50	132H	Battery	15-Dec-24		SIS in Progress	NRIS	NSPI
20-T	663	26-Jul-22	Colchester	50	50	1N	Battery	15-Jun-24		SIS in Progress	NRIS	NSPI
21-T	670	05-Aug-22	Colchester	97.98	97.98	L-7005	Wind	28-Feb-26		SIS in Progress	NRIS	NSPI
22-T	671	05-Aug-22	Halifax	88.96	88.96	L-6004	Wind	28-Feb-26		SIS in Progress	NRIS	NSPI
23-T	669	04-Aug-22	Cumberland	99	99	L-6613	Wind	31-Dec-25		SIS in Progress	NRIS	N/A
24-T	668	03-Aug-22	Antigonish	94.4	94.4	L-7003	Wind	01-Dec-25		SIS in Progress	NRIS	N/A
25-T	618	21-Jul-21	Guysborough	130.2	130.2	L-6515	Wind	01-Jan-25		SIS in Progress	NRIS	N/A
26-T	673	09-Aug-22	Hants	33.6	33.6	L-6054	Wind	31-Dec-24		SIS in Progress	NRIS	N/A
27-T	675	10-Aug-22	Queens	112.5	112.5	50W	Wind	01-Dec-24		SIS in Progress	NRIS	N/A
28-T	677	23-Sep-22	Yarmouth	80	80	L-6024	Wind	31-Dec-25		SIS in Progress	NRIS	N/A
29-D	676	15-Aug-22	Halifax	0.74	0.6475	103H-431	Solar	01-Jun-22		SIS in Progress	N/A	N/A
		Totals:		1103.05	1103							

Nova Scotia Power - Interconnection Request Queue: Page 3 of 3

ERIS - Energy Resource Interconnection Service
NRIS - Network Resource Interconnection Service
N/A - Not Applicable

T - Transmission Interconnection Request
D - Distribution Interconnection Request

*** Note: Queue reflects current list of IR's which have established an advanced queue position per GIP/DGIP Section 4.1**

Figure 2: NSPI Combined T/D Advanced Interconnection Queue

According to NSPI's Generator Interconnection Procedure (GIP), Transmission Service Requests which are in higher queued positions than IR669 will be modelled and included in IR669 study base cases. For IRs which are considered electrically remote and do not impact the IR under study, they can be omitted from the modelling and analysis to be time efficient.

For the purpose of this SIS, the following higher queued IRs are considered electrically remote to IR669 and are not modelled in detail for the SIS study cases:

- IR557
- IR569
- IR566
- IR604
- IR597
- IR653
- IR654
- IR672
- IR664
- IR671

Many of the higher queued IRs which are included in this SIS study have their own SIS study in progress, therefore they are modelled with the details that are available. In some cases, these models may not represent the exact final configurations of the IR.

As of 2023/01/31, the "OATT Transmission Service Queued System Impact Studies" (available on NSPI's OASIS site) is as follows:

OATT Transmission Service
Queued System Impact Studies
Active January 31, 2023

Item	Project	Date & Time of Service Request	Project Type	Project Location	Requested In-Service Date	Project Size (MW)	Status
1	TSR 400	July 22, 2011	Point-to-point	NS-NB*	May 2019	330	System Upgrades in Progress
2	TSR 411	January 19, 2021	Point-to-point	NS-NB*	January 1, 2028	550	Facilities Study in Process

* Indicates project as being located near provincial border.

Figure 3: OATT Transmission Service Queued System Impact Studies

TSR 411 has an expected 01/01/2028 in service date, and a Facilities Study (FAC) to determine required upgrades to the NS transmission system is currently in progress. The following notice has been posted to the OASIS site regarding this TSR:

"Due to ongoing development discussions and engineering studies, the Transmission System Network Upgrades identified as part of Transmission Service Request #411 will not be included in the System Impact Study (SIS) Analysis for Generator Interconnection Procedures (GIP) Study Groups #32 and #33. GIP Study Group #32 and #33 analysis will be limited to the 2022 Transmission System configuration plus any material Network Upgrades identified in higher queued projects."

2.0 Technical Model

To facilitate the power flow analysis, a windfarm equivalent was created for the 17 machines, their step-up transformers, and collector circuits. This was based on the 750V machine terminal voltage that was stepped up to 34.5kV for transmission along the collector circuits to the IR669 substation. The IR669 substation is modelled where voltage is stepped up to 138kV to the spur line, approximately 2.75 km in length, to the POI at the 138 kV transmission line L-6613 (between 1N-Onslow and 74N-Springhill, ~24 km from 1N-Onslow).

The PSSE model for power flow is shown in Figure 4. Data for the individual 34.5/0.75 kV transformers is based on 8.5% impedance on 6.35 MVA with a 12.0 X/R ratio. The ICIF transformer is based on 8.33% impedance on 2x30 MVA ONAN rating with a 20.0 X/R ratio.

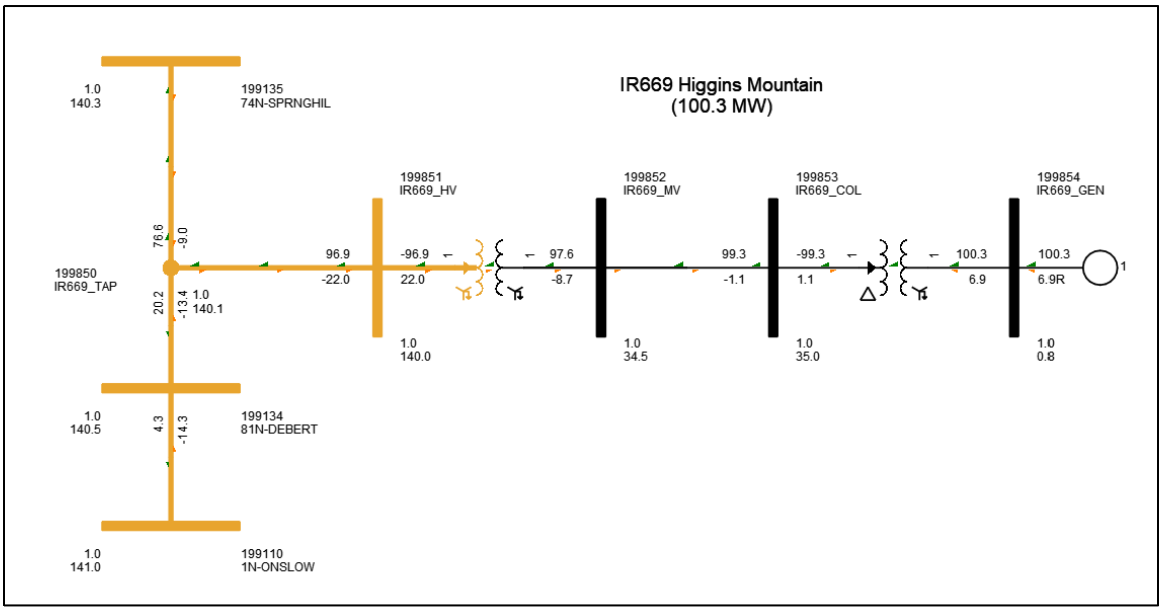


Figure 4: Proposed Interconnection of IR669

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.

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

- Summer: 65%
- Light load: 30%

The load forecast is projecting an increase in forecasted non-firm (interruptible) and moderate annual 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 2026 were used in this study based on the planned in-service date of IR669. Base cases for this SIS were selected to stress overall system and local conditions.

2.2 Generating Facility

IR669 will have 17 Nordex N163 wind turbine generators, each rated at 5.9 MW. Each unit will generate at 750V 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) transformers are rated 30/40/50 MVA, Y/Y with Δ tertiary, DETC with +/- 5% taps (4 equal steps), and 8.33% 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 a Type 3 Doubly-Fed Induction Generator (DFIG). 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 Nordex N163/5.9 wind turbines with maximum active power output are each capable of a reactive power range of 2.35 to -2.35 MVAR at 96-106% of nominal voltage, 1.8 to -1.985 MVAR at 94% of nominal voltage, and 1.6 to -2.35 MVAR at 110% of nominal voltage.

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 2022 system configuration (plus higher queued IRs) with IR669 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. Reactive power can be provided by the WTG facility or by continually acting auxiliary devices such as STATCOM, DSTATCOM or synchronous condenser. Rated dynamic reactive power must be available through the full range of real power output of the WTG facility, from zero to full power.

PSSE was used to simulate the machine capability in maximum 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:

- **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 IR669 to the existing system, short-circuit values are for the existing system - before the addition of IR669.
- **m** = 2 in accordance with IEC 61400-21 for WTGs.
- **N_{wt}** = number of WTGs at IR669.
- **$N_{10,i}$** and **$N_{120,i}$** = number of switching operations of the individual wind turbine within a 10 and 120 minute period, respectively.
- **$c_i(\psi_k,v_a)$** = 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.
- **$k_{f,i}(\psi_k)$** = flicker step factor of the individual wind turbine.
- **$S_{n,i}$** = rated apparent power of the individual wind turbine.

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

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 17 wind turbines and 4 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.

Planned system modifications up to 2026 were modelled to develop base cases to test system reliability in accordance with NS Power and NPCC design criteria:

- Light load; variable NS-NB interchange
- Summer peak; variable NS-NB interchange
- Winter peak; variable NS-NB interchange

Power flow was run with the contingencies on each of the base cases listed in Section 3.4; with IR669 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 2026 study year and system configuration. Spring light load, 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 IR669 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 138 kV line L-6613 is classified as a BPS element. The 138 kV bus 1N-Onslow is also identified as 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 will be used to determine if IR669 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 IR669's generators.

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

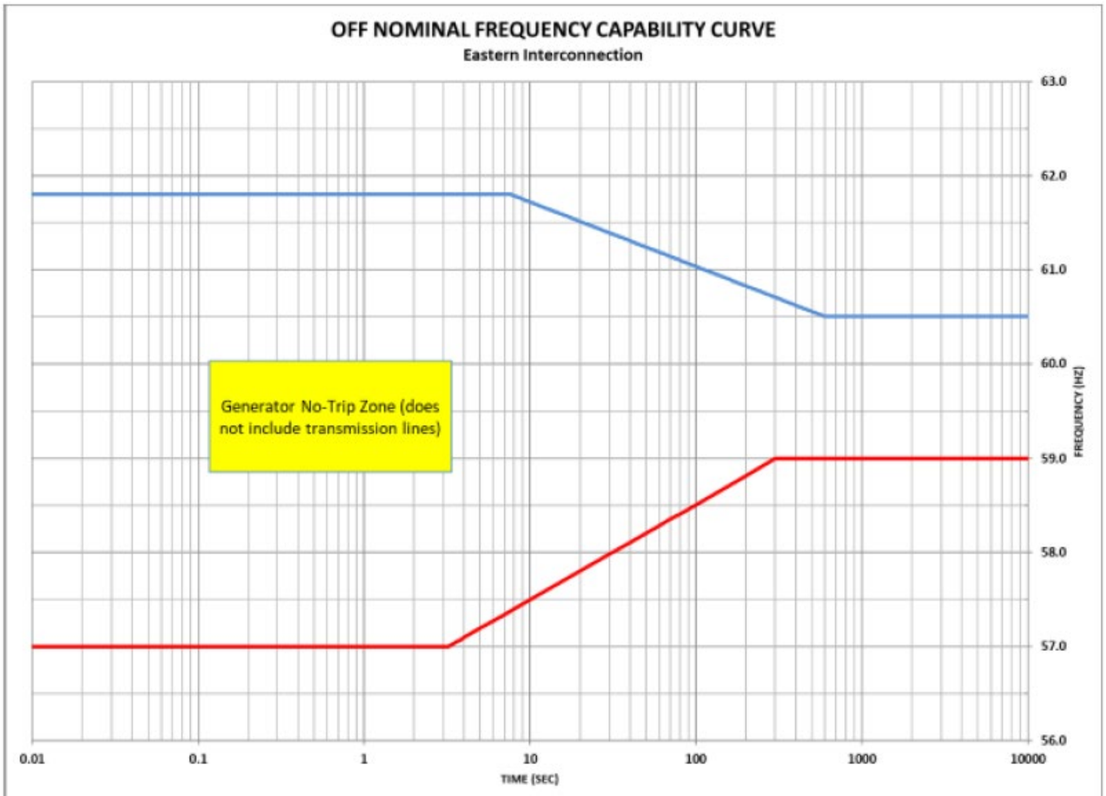
Nova Scotia is connected to the rest of the North American power grid by the following three AC transmission lines:

- 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 1N-Onslow to avoid thermal overloads on the in-service 138kV transmission lines. This controlled separation will open-end L-6613 at 1N-Onslow and 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. IR669 is required to remain online and not trip under this scenario. It is noted that with the existing RAS configuration, the IR669 POI becomes disconnected from the NS electrical island following the RAS operation. As a result, the RAS will require modification to keep IR669 connected to the NS electrical island following RAS operation.

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

In addition to the test, IR669 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 5. It must also have the capability of riding through a rate of change of frequency of 4 Hz/s, as per Transmission Service Interconnection Requirements (TSIR) Section 7.4.2.



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

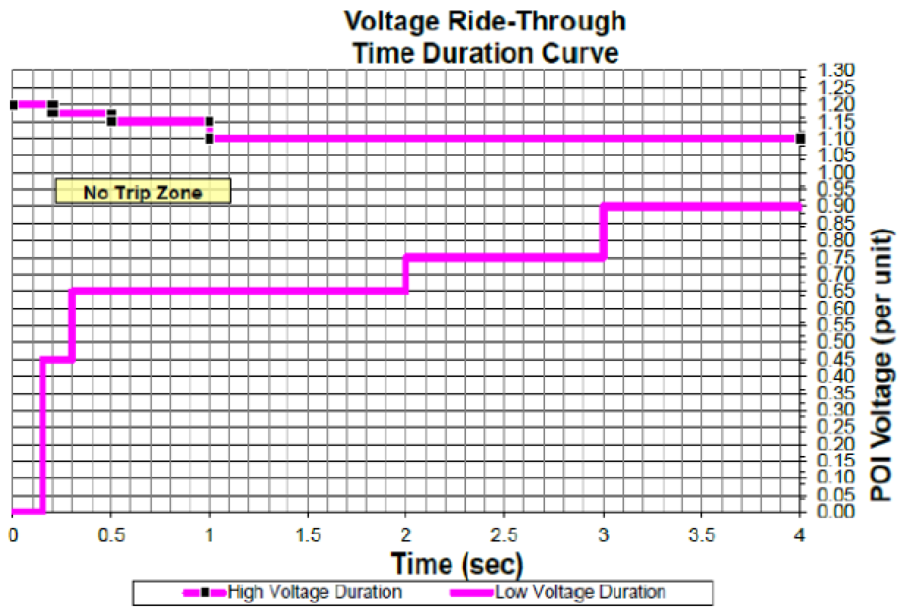
Figure 5: Off-nominal frequency curve (PRC-024-2 and PRC-006-NPCC-2 combined)

2.3.9 Voltage Ridethrough

IR669 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 6.

This test is performed by applying a 3-phase fault to the HV and LV buses of the ICIF for 9 cycles. IR669 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 6: PRC-024-2 Attachment 2: Voltage ridethrough requirements

2.3.10 Loss Factor

Loss factor is calculated by running the power flow using a winter peak base case with and without IR669, while keeping 91H-Tufts Cove generation as the NS area interchange bus. The loss factor for IR669 is the differential MW displaced or increased at 91H-Tufts Cove generation calculated as a percentage of IR669'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 for the loss factor analysis.

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.

3.0 Technical Analysis

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

3.1 Short Circuit

IR669 will not impact 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 short circuit capability was modelled based on the comparable 5.7 MW unit described in Nordex document "Short-Circuit Currents of Nordex Wind Turbines - E0003661765 rev. 3". The calculated short circuit levels in the area before and after this development are provided in *Table 2: Short circuit levels, 3-ph, in MVA*.

The short circuit levels provided with IR669 in service remain well below the design rating of NSPIs 138 kV breakers.

Table 2: Short circuit levels, 3-ph, in MVA

Maximum Generation: All Generation On, All Transmission Lines In-Service		
Measured Bus	***Without IR669 (MVA)***	***With IR669 (MVA)***
81N-Debert (138 kV)	1633	1755
74N-Springhill (138 kV)	1348	1391
ICIF 138 kV	1261	1421
ICIF 34.5 kV	458	664

Minimum Generation: PA, ML, LG1 On, All Transmission Lines In-Service		
Measured Bus	***Without IR669 (MVA)***	***With IR669 (MVA)***
81N-Debert (138 kV)	1028	1158
74N-Springhill (138 kV)	953	1021
ICIF 138 kV	881	1041
ICIF 34.5 kV	396	602
Minimum Generation: PA, ML, LG1 On, L-6613 (1N to IR669) Out of Service		
Measured Bus	***Without IR669 (MVA)***	***With IR669 (MVA)***
81N-Debert (138 kV)	813	820
74N-Springhill (138 kV)	699	836
ICIF 138 kV	404	564
ICIF 34.5 kV	259	465

Regarding SCR, the IC noted: "as a rule, for systems with SCR=3 (or lower), Nordex recommends completing detailed stability studies to evaluate the project's electrical performance." Minimum fault levels occur when L-6613 (138 kV line from 1N-Onslow to the IR669 ICIF) is out of service. In this scenario, the SCR at the low side of IR669's substation step down transformer is calculated as 2.6 (259 MVA / 100.3 MW) - at IR669's 34.5 kV bus. This information should be provided to Nordex for design specification as the detailed parameters for collector circuit length and generator step-up transformers may further reduce the SCR measured at the wind turbines' HV terminals.

Furthermore, as per the NSPI TSIR Section 7.4.15, as the system short circuit level declines over time with changes to transmission configuration and generation mix, the Generating Facility must be able to accommodate these changes.

3.2 Power Factor

The NSPI TSIR defines two key requirements related to the power factor of the WTG facility:

- The WTG facility must be capable of operating between 0.95pu lagging to 0.95pu leading net power factor, measured at the high side of the ICIF transformer.
- The rated reactive power must be available through the full range of real power output, from zero to full power.

Information provided by the IC states the 138/34.5 kV transformers have de-energized tap changers with ±5% taps in 5 equal steps. The 34.5/0.75 kV generator step-up transformers were noted to be supplied with HV de-energized tap changers with 4 x 0.5 kV taps.

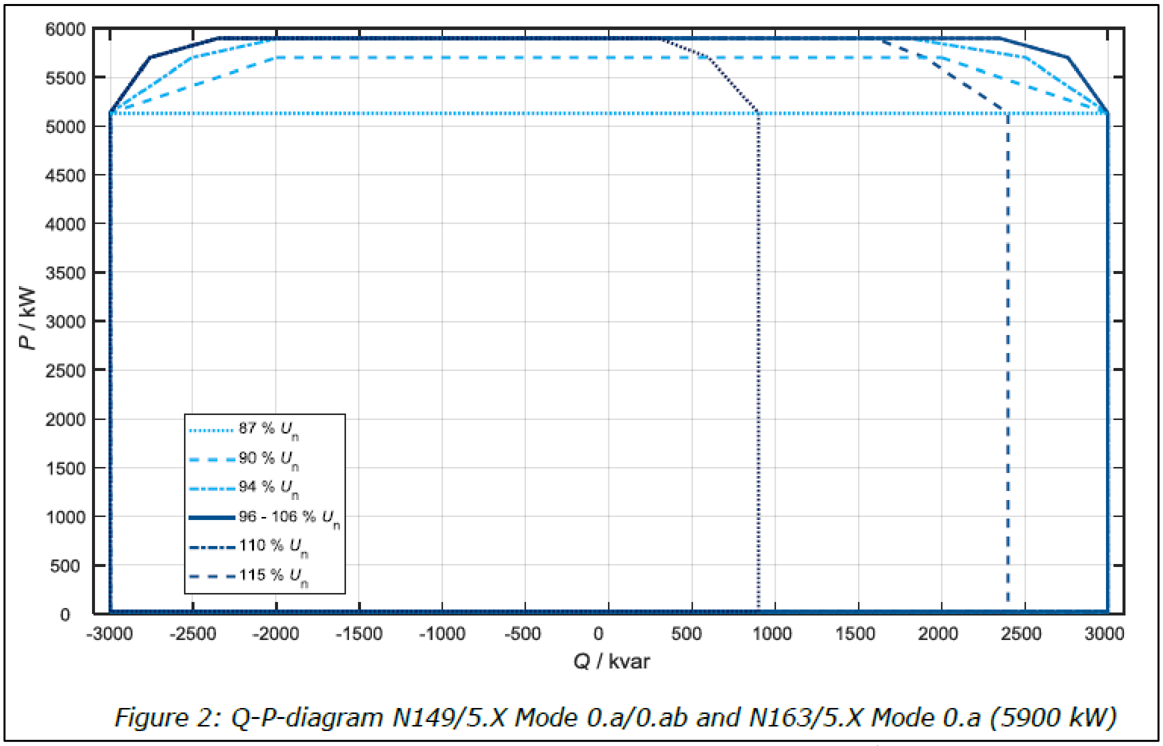


Figure 7: Nordex N163/5.9 reactive power capability[1]

Using the reactive power capability shown in *Figure 7: Nordex N163/5.9 reactive power capability*, various levels were calculated and are displayed below in *Table 3: Power factor analysis results*.

Table 3: Power factor analysis results

Breakpoints on reactive capability curve (V = 0.96 to 1.06pu)	IR669 rated output (17 x 5.9 MW WTG units)				Measurements at the HV terminals of the ICIF substation				Meets pf requirement?
	MW	MVAR	MVA	pf	MW	MVAR	MVA	pf	
Maximum Reactive Injection	100.30	39.95	107.96	0.929	97.10	12.50	97.90	0.992	No
Maxiumum Reactive Absorption	100.30	-39.95	107.96	0.929	96.10	-76.40	122.77	0.783	Yes
Maximum Reactive Injection - no wind	0.00	28.90	28.90	0.000	-	-	-	-	No
Maxiumum Reactive Absorption - no wind	0.00	-32.30	32.30	0.000	-	-	-	-	No

The Nordex technical bulletin's reactive power capability, shown in Figure 7, shows that the reactive power injection capability is reduced at full output at nominal voltage. When the wind farm is operating at its max active power nameplate capacity, power factor measured at the ICIF HV terminals is not within limits. If the actual collector circuit differs

[1] Nordex Developer Package, document ID: 2009087EN rev. 1, 2021-09-29.

significantly from the assumed generic collector circuit parameters used, this analysis should be re-evaluated.

IR669 therefore does not meet NS Power's 0.95 lagging power factor requirement at the HV terminals of the ICIF substation based on PSSE simulations using parameters provided by the IC (at V=1.0pu) and assumptions as provided in Section 1.2.

IR669 is required to produce/absorb rated reactive power at all production levels, from zero up to its full rated output. The reactive capability shown in Figure 7 above shows the active power range of full output to minimum non-zero output. For the wind turbine connected to the grid with no wind (or wind below the switch-on speed), no reactive power capability is available. There is an optional STATCOM function for which the following values in Figure 8 apply. The STATCOM function therefore provides ~72% of the rated reactive power injection capability at zero active power.

Table 1: Maximum possible reactive power during WT standstill in relation to the voltage at the reference point

		Without STATCOM	With STATCOM
Maximum reactive power range (10-min-average)	90 % U_n -Q...+Q / kvar	0	-1700
		0	1700
	100 % U_n -Q...+Q / kvar	0	-1900
		0	1700
	110 % U_n -Q...+Q / kvar	0	-1900
		0	0

Figure 8: Reactive Power Capability values (pu) at no wind conditions, at LV terminals

The Nordex N163/5.9 MW machine does not meet either of the two key requirements related to power factor. Additional dynamic reactive power compensation will therefore be required to inject reactive power to achieve the 0.95 net power factor requirement, measured at the high side of the ICIF transformer, as well as to provide rated reactive power at the zero-power operating point.

3.3 Voltage Flicker

NS Power's voltage flicker requirements are:

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

The voltage flicker calculations use data provided by the IC for the Nordex N163/5.9 MW machines based on IEC Standard 61400-21-1. A flicker coefficient was provided based on active power output. The voltage flicker emission levels (Pst=Plt) are calculated at the POI for various system conditions based on the rated apparent power of the Nordex N163/5.9 MW turbine of 6.351 MVA, as listed in Table 4.

Table 4: Calculated voltage flicker

System Conditions	Continuous (Pst=Plt)
Maximum Generation	
All transmission facilities in service	0.083
Minimum Generation	
All transmission facilities in service	0.119
L-6613 (1N to IR669) out of service	0.259

IR669 therefore meet NS Power's voltage flicker requirements under normal operating conditions and all but one contingency condition because the continuous voltage flicker emission, Plt, can exceed 0.25 for the minimum generation case with L-6613 between 1N and IR669 out of service. Should this cause an issue with other NS Power Customers, IR669 would be curtailed for the duration of the contingency event.

The generator must also meet IEEE Standard 519 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 5: *Base Case Dispatch*. They were selected to reflect conditions under varying amounts of low/high area load and varying amounts of import/export with New Brunswick Power. Cases were also developed to represent both typical wind generation percentage in the province as well as maximum generation.

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 5: Base Case Dispatch

Case	IR 669	NS Load	NS-NB	NS-NL	Wind	Small Hydro	BESS	CBX	ONI	ONS	PHP Load	TR	PT
SML_01-1	0	619	150	-475	122	34	0	370	411	218	134	80	75
SML_01-2	100	619	150	-475	221	34	0	293	336	239	209	80	75
SML_02-1	0	611	330	-375	535	34	0	165	333	3	191	80	0
SML_02-2	100	611	330	-375	634	34	-70	165	333	75	191	80	0

Case	IR 669	NS Load	NS-NB	NS-NL	Wind	Small Hydro	BESS	CBX	ONI	ONS	PHP Load	TR	PT
SML_03-1	0	611	0	-475	143	34	-85	303	353	283	134	80	0
SML_03-2	100	611	0	-375	242	34	-85	204	255	282	134	80	0
SML_04-1	0	611	0	-209	535	34	-150	1	170	121	191	80	0
SML_04-2	100	611	0	-120	634	34	-150	-87	81	129	191	80	0
SUM_01-1	0	1331	150	-475	122	35	150	567	642	441	76	160	100
SUM_01-2	100	1315	150	-475	221	35	150	458	537	433	76	160	100
SUM_02-1	0	1331	330	-475	713	35	0	448	642	269	196	100	75
SUM_02-2	100	1331	330	-475	812	35	0	448	622	348	196	80	75
SUM_03-1	0	1331	500	-475	713	35	0	519	770	226	136	160	85
SUM_03-2	100	1331	500	-475	812	35	0	509	682	233	136	80	75
SUM_04-1	0	1331	0	-475	136	35	0	542	624	524	76	162	75
SUM_04-2	100	1331	0	-475	235	35	0	542	543	539	76	80	75
SUM_05-1	0	1296	0	-475	713	35	-75	252	362	299	216	0	0
SUM_05-2	100	1296	0	-475	812	35	-75	252	362	391	216	0	0
WIN_01-1	0	2149	0	-320	122	149	0	838	1015	847	11	324	155
WIN_01-2	100	2149	0	-320	221	149	0	740	923	850	11	324	155
WIN_02-1	0	2131	150	-320	713	149	0	495	780	525	11	240	75
WIN_02-2	100	2131	150	-320	812	149	0	495	701	543	11	160	75
WIN_03-1	0	2106	-300	-320	713	149	0	302	446	644	131	80	0
WIN_03-2	100	2106	-300	-320	812	149	0	303	446	735	131	80	0
WIN_04-1	0	2131	330	-320	713	149	150	495	814	425	11	275	75
WIN_04-2	100	2131	330	-320	812	149	150	491	718	427	11	180	75
WIN_05-1	0	2121	0	-320	713	149	0	501	638	535	11	80	75
WIN_05-2	100	2121	0	-320	812	149	0	501	638	631	11	80	75

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 transmission connected wind only.
Note 4: “NS Load” excludes PHP load and BESS charging load (when applicable).
Note 5: “BESS” negative values indicate charging, positive values indicate discharging.

Regarding the case dispatches:

- Cases designated “-1” model IR669 as offline. Cases designated “-2” include IR669 operating at full active power output.
- WIN_0X cases represent winter peak load. Total transmission connected wind generation is varied, along with flows on the NS-NB interface. Small hydro generation is operated at high output.
- SUM_0X cases represent summer peak load. Total transmission connected wind generation is varied, along with flows on the NS-NB interface. Small hydro generation is operated at low output.
- SML_0X cases represent the spring light load, which is typically the minimum loading period experienced by the NS system. Total transmission connected wind generation is varied, along with flows on the NS-NB interface. Small hydro generation is operated at low output.

3.4.2 Contingencies

The steady state power flow analysis includes the contingencies listed in Table 6.

Table 6: Steady State Contingencies

ID	Element	Type	Location	ID	Element	Type	Location
1	101S_L-7011	Line fault	101S-Woodbine	108	67N-705	Breaker fail	67N-Onslow
2	101S_L-7012	Line fault	101S-Woodbine	109	67N-706	Breaker fail	67N-Onslow
3	101S_L-7015	Line fault	101S-Woodbine	110	67N-710	Breaker fail	67N-Onslow
4	101S_L-8004_G0	Line fault	101S-Woodbine	111	67N-711_G0	Breaker fail	67N-Onslow
5	101S_ML-BIPOLE	HVDC line fault	101S-Woodbine	112	67N-712	Breaker fail	67N-Onslow
6	101S_ML-POLE1	HVDC line fault	101S-Woodbine	113	67N-713	Breaker fail	67N-Onslow
7	101S_ML-POLE2	HVDC line fault	101S-Woodbine	114	67N-811_G0	Breaker fail	67N-Onslow
8	101S-701	Breaker fail	101S-Woodbine	115	67N-813	Breaker fail	67N-Onslow
9	101S-702	Breaker fail	101S-Woodbine	116	67N-814_G0	Breaker fail	67N-Onslow
10	101S-703	Breaker fail	101S-Woodbine	117	67N-T71	Transformer fault	67N-Onslow
11	101S-704	Breaker fail	101S-Woodbine	118	67N-T81	Transformer fault	67N-Onslow
12	101S-705	Breaker fail	101S-Woodbine	119	67N-T82	Transformer fault	67N-Onslow
13	101S-706	Breaker fail	101S-Woodbine	120	74N_L-6514	Line fault	74N-Springhill
14	101S-711	Breaker fail	101S-Woodbine	121	74N_L-6536	Line fault	74N-Springhill
15	101S-712	Breaker fail	101S-Woodbine	122	74N-B61	Bus fault	74N-Springhill
16	101S-713	Breaker fail	101S-Woodbine	123	74N-C61	Shunt fault	74N-Springhill
17	101S-811	Breaker fail	101S-Woodbine	124	74N-T61	Transformer fault	74N-Springhill
18	101S-812_G0	Breaker fail	101S-Woodbine	125	79N_L-6507	Line fault	79N-Hopewell
19	101S-813_G0	Breaker fail	101S-Woodbine	126	79N_L-6508	Line fault	79N-Hopewell
20	101S-814	Breaker fail	101S-Woodbine	127	79N_L-8003_G0	Line fault	79N-Hopewell
21	101S-816	Breaker fail	101S-Woodbine	128	79N-T81_G0	Transformer fault	79N-Hopewell
22	101S-T81	Transformer fault	101S-Woodbine	129	85S_L-6545	Line fault	85S-Wreck Cove

ID	Element	Type	Location	ID	Element	Type	Location
23	101S-T82	Transformer fault	101S-Woodbine	130	88S_L-7014	Line fault	88S-Lingan
24	103H_L-6008	Line fault	103H-Lakeside	131	88S_L-7021	Line fault	88S-Lingan
25	103H_L-6033	Line fault	103H-Lakeside	132	88S_L-7022	Line fault	88S-Lingan
26	103H_L-6038	Line fault	103H-Lakeside	133	88S-710	Breaker fail	88S-Lingan
27	103H-600	Breaker fail	103H-Lakeside	134	88S-711	Breaker fail	88S-Lingan
28	103H-608	Breaker fail	103H-Lakeside	135	88S-713	Breaker fail	88S-Lingan
29	103H-681	Breaker fail	103H-Lakeside	136	88S-714	Breaker fail	88S-Lingan
30	103H-881	Breaker fail	103H-Lakeside	137	88S-715	Breaker fail	88S-Lingan
31	103H-B61	Bus fault	103H-Lakeside	138	88S-720	Breaker fail	88S-Lingan
32	103H-B62	Bus fault	103H-Lakeside	139	88S-721	Breaker fail	88S-Lingan
33	103H-T61	Transformer fault	103H-Lakeside	140	88S-722	Breaker fail	88S-Lingan
34	103H-T63	Transformer fault	103H-Lakeside	141	88S-723_G0	Breaker fail	88S-Lingan
35	103H-T81	Transformer fault	103H-Lakeside	142	88S-G2	Generator trip	88S-Lingan
36	104H-600	Breaker fail	104H-Kempt Road	143	88S-G3	Generator trip	88S-Lingan
37	104W-G1	Generator trip	104W-Brooklyn	144	88S-G4	Generator trip	88S-Lingan
38	110W-B61	Bus fault	110W-South Canoe	145	88S-T71	Transformer fault	88S-Lingan
39	110W-T62	Transformer fault	110W-South Canoe	146	88S-T72	Transformer fault	88S-Lingan
40	11V_11V-B51	Bus fault	11V-Paradise	147	89S-G1	Generator trip	89S-Point Aconi
41	120H_L-6005	Line fault	120H-Brushy Hill	148	90H_L-6002	Line fault	90H-Sackville
42	120H_L-6010	Line fault	120H-Brushy Hill	149	90H_L-6003	Line fault	90H-Sackville
43	120H_L-6011	Line fault	120H-Brushy Hill	150	90H_L-6004	Line fault	90H-Sackville
44	120H_L-6016	Line fault	120H-Brushy Hill	151	90H_L-6009	Line fault	90H-Sackville
45	120H_L-6051	Line fault	120H-Brushy Hill	152	90H-605	Breaker fail	90H-Sackville
46	120H_L-7008	Line fault	120H-Brushy Hill	153	90H-611	Breaker fail	90H-Sackville
47	120H_L-7009	Line fault	120H-Brushy Hill	154	91H_L-5012	Line fault	91H-Tufts Cove
48	120H-621	Breaker fail	120H-Brushy Hill	155	91H_L-5041	Line fault	91H-Tufts Cove
49	120H-622	Breaker fail	120H-Brushy Hill	156	91H_L-5049	Line fault	91H-Tufts Cove
50	120H-623	Breaker fail	120H-Brushy Hill	157	91H-511	Breaker fail	91H-Tufts Cove
51	120H-624	Breaker fail	120H-Brushy Hill	158	91H-516	Breaker fail	91H-Tufts Cove
52	120H-626	Breaker fail	120H-Brushy Hill	159	91H-521	Breaker fail	91H-Tufts Cove
53	120H-627	Breaker fail	120H-Brushy Hill	160	91H-523	Breaker fail	91H-Tufts Cove
54	120H-628	Breaker fail	120H-Brushy Hill	161	91H-G3	Generator trip	91H-Tufts Cove
55	120H-629	Breaker fail	120H-Brushy Hill	162	91H-G4	Generator trip	91H-Tufts Cove
56	120H-710	Breaker fail	120H-Brushy Hill	163	91H-G5	Generator trip	91H-Tufts Cove
57	120H-711	Breaker fail	120H-Brushy Hill	164	91H-G6	Generator trip	91H-Tufts Cove
58	120H-712	Breaker fail	120H-Brushy Hill	165	91H-T11	Transformer fault	91H-Tufts Cove
59	120H-713	Breaker fail	120H-Brushy Hill	166	91H-T62	Transformer fault	91H-Tufts Cove
60	120H-714	Breaker fail	120H-Brushy Hill	167	91N-701	Breaker fail	91N-Dalhousie Wind

ID	Element	Type	Location	ID	Element	Type	Location
61	120H-715	Breaker fail	120H-Brushy Hill	168	91N-702	Breaker fail	91N-Dalhousie Wind
62	120H-716	Breaker fail	120H-Brushy Hill	169	91N-703	Breaker fail	91N-Dalhousie Wind
63	120H-720	Breaker fail	120H-Brushy Hill	170	91N-B71	Bus fault	91N-Dalhousie Wind
64	120H-SVC	Reactive device trip	120H-Brushy Hill	171	99W_99W-B61	Bus fault	99W-Bridgewater
65	120H-T71	Transformer fault	120H-Brushy Hill	172	99W_99W-B62	Bus fault	99W-Bridgewater
66	120H-T72	Transformer fault	120H-Brushy Hill	173	99W_99W-T71	Transformer fault	99W-Bridgewater
67	1C-G2	Generator trip	1C-Point Tupper	174	99W_99W-T72	Transformer fault	99W-Bridgewater
68	1N_L-6001	Line fault	1N-Onslow	175	99W_L-6025	Line fault	99W-Bridgewater
69	1N_L-6503	Line fault	1N-Onslow	176	99W-708	Breaker fail	99W-Bridgewater
70	1N_L-6613	Line fault	1N-Onslow	177	99W-709	Breaker fail	99W-Bridgewater
71	1N_L-6613A	Line fault	1N-Onslow	178	99W-T71	Transformer fault	99W-Bridgewater
72	1N_L-6613B	Line fault	1N-Onslow	179	99W-T72	Transformer fault	99W-Bridgewater
73	1N-600	Breaker fail	1N-Onslow	180	DCT_L-5039][L-6033	Double cct tower	Bayers Lake
74	1N-601	Breaker fail	1N-Onslow	181	DCT_L-6005][L-6016	Double cct tower	Sackville
75	1N-613	Breaker fail	1N-Onslow	182	DCT_L-6010][L-6005	Double cct tower	Sackville
76	1N-B61	Bus fault	1N-Onslow	183	DCT_L-6011][L-6010	Double cct tower	Sackville
77	1N-B62	Bus fault	1N-Onslow	184	DCT_L-6033][L-6035	Double cct tower	Halifax
78	1N-C61	Reactive device trip	1N-Onslow	185	DCT_L-6507][L-6508	Double cct tower	Trenton
79	1N-T1	Transformer fault	1N-Onslow	186	DCT_L-7003][L-7004_G0	Double cct tower	Canso Causeway
80	1N-T4	Transformer fault	1N-Onslow	187	DCT_L-7008][L-7009	Double cct tower	Bridgewater
81	1N-T65	Transformer fault	1N-Onslow	188	DCT_L-7009][L-8002	Double cct tower	Sackville
82	3C_L-7003	Line fault	3C-Port Hastings	189	DCT_L-7021][L-6534	Double cct tower	Lingan / VJ
83	3C_L-7004	Line fault	3C-Port Hastings	190	IR669	Generator trip	POI
84	3C_L-7005_G0	Line fault	3C-Port Hastings	191	MEMRAMCOOK_L1159	Line fault	New Brunswick
85	3C-710_G0	Breaker fail	3C-Port Hastings	192	MEMRAMCOOK_L1160	Line fault	New Brunswick
86	3C-711	Breaker fail	3C-Port Hastings	193	MEMRAMCOOK_ME3-1	Breaker fail	New Brunswick
87	3C-712	Breaker fail	3C-Port Hastings	194	SALISBURY_L3004	Line fault	New Brunswick
88	3C-713	Breaker fail	3C-Port Hastings	195	SALISBURY_L3006	Line fault	New Brunswick
89	3C-714	Breaker fail	3C-Port Hastings	196	SALISBURY_L3013	Line fault	New Brunswick
90	3C-715	Breaker fail	3C-Port Hastings	197	SALISBURY_SA3-2	Breaker fail	New Brunswick
91	3C-716	Breaker fail	3C-Port Hastings				
92	3C-T71	Transformer fault	3C-Port Hastings				
93	3C-T72	Transformer fault	3C-Port Hastings				
94	3S_L-6539	Line fault	3S-Gannon Rd				
95	43V_L-6054	Line fault	43V-Canaan Rd				
96	48C-G1	Generator trip	48C-PHP				
97	50N-G5	Generator trip	50N-Trenton				

ID	Element	Type	Location	ID	Element	Type	Location
98	50N-G6	Generator trip	50N-Trenton				
99	67N_L-7001	Line fault	67N-Onslow				
100	67N_L-7002	Line fault	67N-Onslow				
101	67N_L-7019	Line fault	67N-Onslow				
102	67N_L-8001_G0	Line fault	67N-Onslow				
103	67N_L-8002	Line fault	67N-Onslow				
104	67N-701	Breaker fail	67N-Onslow				
105	67N-702	Breaker fail	67N-Onslow				
106	67N-703	Breaker fail	67N-Onslow				
107	67N-704	Breaker fail	67N-Onslow				

3.4.3 Evaluation

The steady state contingencies evaluated in this study demonstrate IR669 does not require Network Upgrades beyond the POI to operate at its full capacity of 100.3 MW as NRIS.

As a note unrelated to NSPI system performance, the two 138-34.5 kV, 30/40/50 MVA ICIF transformers can be overloaded to 108% of their top ratings while the facility is at full generation and full VAR capacity. IR669 can generate up to 100.3 MW and +/- 40 MVAR, for a total of 108 MVA. Accounting for power losses in the ICIF equipment, the loading on these two transformers can exceed 100 MVA under some system conditions. It is recommended that the IC confirm that the ratings of these transformers are suitable for these loading levels.

Single line diagrams showing the load flows of each of the base 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 any abnormalities.

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 7.

Table 7: Stability Base Cases

Case	IR 669	NS Load	NS-NB	NS-NL	Wind	Small Hydro	BESS	CBX	ONI	ONS	PHP Load	TR	PT
SML_01-1	0	619	150	-475	122	34	0	370	411	218	134	80	75
SML_01-2	100	619	150	-475	221	34	0	293	336	239	209	80	75
SML_02-1	0	611	330	-375	535	34	0	165	333	3	191	80	0
SML_02-2	100	611	330	-375	634	34	-70	165	333	75	191	80	0
SML_03-1	0	611	0	-475	143	34	-85	303	353	283	134	80	0
SML_03-2	100	611	0	-375	242	34	-85	204	255	282	134	80	0
SML_04-1	0	611	0	-209	535	34	-150	1	170	121	191	80	0
SML_04-2	100	611	0	-120	634	34	-150	-87	81	129	191	80	0
SUM_01-1	0	1331	150	-475	122	35	150	567	642	441	76	160	100
SUM_01-2	100	1315	150	-475	221	35	150	458	537	433	76	160	100
SUM_02-1	0	1331	330	-475	713	35	0	448	642	269	196	100	75
SUM_02-2	100	1331	330	-475	812	35	0	448	622	348	196	80	75
SUM_03-1	0	1331	500	-475	713	35	0	519	770	226	136	160	85
SUM_03-2	100	1331	500	-475	812	35	0	509	682	233	136	80	75
SUM_04-1	0	1331	0	-475	136	35	0	542	624	524	76	162	75
SUM_04-2	100	1331	0	-475	235	35	0	542	543	539	76	80	75
SUM_05-1	0	1296	0	-475	713	35	-75	252	362	299	216	0	0
SUM_05-2	100	1296	0	-475	812	35	-75	252	362	391	216	0	0
WIN_01-1	0	2149	0	-320	122	149	0	838	1015	847	11	324	155
WIN_01-2	100	2149	0	-320	221	149	0	740	923	850	11	324	155
WIN_02-1	0	2131	150	-320	713	149	0	495	780	525	11	240	75
WIN_02-2	100	2131	150	-320	812	149	0	495	701	543	11	160	75
WIN_03-1	0	2106	-300	-320	713	149	0	302	446	644	131	80	0
WIN_03-2	100	2106	-300	-320	812	149	0	303	446	735	131	80	0
WIN_04-1	0	2131	330	-320	713	149	150	495	814	425	11	275	75
WIN_04-2	100	2131	330	-320	812	149	150	491	718	427	11	180	75
WIN_05-1	0	2121	0	-320	713	149	0	501	638	535	11	80	75

Case	IR 669	NS Load	NS-NB	NS-NL	Wind	Small Hydro	BESS	CBX	ONI	ONS	PHP Load	TR	PT
WIN_05-2	100	2121	0	-320	812	149	0	501	638	631	11	80	75

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 transmission connected wind only.
Note 4: "NS Load" excludes PHP load and BESS charging load (when applicable).
Note 5: "BESS" negative values indicate charging, positive values indicate discharging.

3.5.2 Contingencies

The contingencies tested for this study are listed in Table 8.

Table 8: Stability Contingency List

ID	Contingency	Fault	Tripped Elements	Notes
1	101S BBU 101S-811	breaker fail @ 101S	101S-T81 ML Pole 2	
2	101S BBU 101S-812	breaker fail @ 101S	L8004: 101S/79N ML Pole 2	G5/G6 SPS
3	101S BBU 101S-813	breaker fail @ 101S	L8004: 101S/79N 101S-T82	G5/G6 SPS
4	101S L8004 3PH Fault	3ph line fault @ 101S	101S/79N	G5/G6 SPS
5	101S MLBIPOLE 1LG Fault	DC line fault @ 101S	ML Pole 1 & 2	
6	101S MLBIPOLE 3P Fault	DC line fault @ 101S	ML Pole 1 & 2	
7	101S MLPOLE1	DC line fault @ 101S	ML Pole 1	
8	101S MLPOLE1	DC line fault @ 101S	ML Pole 2	
9	103H BBU 103H-608	breaker fail @ 103H	L6008:103H/90H L6016:103H/137H L6038:103H/129H 67N-T61	
10	103H BBU 103H-681	breaker fail @ 103H	L8002:103H/67N 103H-T81 103H-T63 L6033:103H/2H/1H	
11	103H BBU 103H-881	breaker fail @ 103H	L8002:103H/67N 103H-T81	
12	103H BKR 103H-600 1P	breaker fail @ 103H	L6008:103H/90H L6016:103H/137H/120H L6038:103H/129H L5039:103H/34H/20H	
13	103H L6008 3PH Fault	3ph line fault @ 103H	L6008:103H/90H	
14	103H L6016 3PH Fault	3ph line fault @ 103H	L6016:103H/137H/120H	
15	103H L6033 3PH Fault	3ph line fault @ 103H	L6033:103H/2H/1H	
16	103H L8002 3PH Fault	3ph line fault @ 103H	L8002:103H/67N	

ID	Contingency	Fault	Tripped Elements	Notes
17	120H BBU 120H-622	breaker fail @ 120H	L6005: 120H/131H L6016: 120H/137H	
18	120H BBU 120H-710	breaker fail @ 120H	120H-T71 L7018: 120H/67N	
19	120H BBU 120H-715	breaker fail @ 120H	L7001:120H/67N L7008:120H/99W	
20	120H L6005 3PH Fault	3ph line fault @ 120H	L6005: 120H/131H	
21	120H L6010 3PH Fault	3ph line fault @ 120H	L6010: 120H/90H	
22	120H L6011 3PH Fault	3ph line fault @ 120H	L6011: 120H/17V	
23	120H L6016 3PH Fault	3ph line fault @ 120H	L6016: 120H/137H	
24	120H L7008 3PH Fault	3ph line fault @ 120H	L7008: 120H/99W	
25	120H L7018 3PH Fault	3ph line fault @ 120H	L7018: 120H/67N	
26	1N BBU 1N-601	breaker fail @ 1N	L6001:1N/82V/132H 67N-T71 1N-T4 1N-C61	
27	1N BBU 1N-613	breaker fail @ 1N	L6613:1N/81N/74N L6503:1N/49N/51N 1N-T65	L8001 NSI
28	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
29	1N L6001 3PH Fault	3ph line fault @ 1N	L6001:1N/82V/132H	
30	1N L6503 3PH Fault	3ph line fault @ 1N	L6503:1N/49N/51N/50N	
31	1N L6613 3PH Fault	3ph line fault @ 1N	L6613:1N/81N/74N	
32	1N BUS 1N-B61 3PH Fault	3ph bus fault @ 1N	1N-T71 1N-T4 L6001:1N/82V/132H 1N-C61	
33	410N L3006 3PH Fault	3ph line fault @ 410N	410N/4592-Salisbury	
34	410N L8001 3PH Fault	3ph line fault @ 410N	L8001:67N/410N	Export SPS
35	67N BBU 67N-701	breaker fail @ 67N	L7002:67N/120H 67N-T71	
36	67N BBU 67N-702	breaker fail @ 67N	L7003:67N/3C L7002:67N/120H	
37	67N BBU 67N-703	breaker fail @ 67N	L7003:67N/3C 67N-T81	
38	67N BBU 67N-704	breaker fail @ 67N	L7001:67N/120H 67N-T81	
39	67N BBU 67N-705	breaker fail @ 67N	L7019:67N/91N L7001:67N/120H	
40	67N BBU 67N-706	breaker fail @ 67N	L7019:67N/91N 67N-T71	
41	67N BBU 67N-710	breaker fail @ 67N	67N-T71 67N-T82	

ID	Contingency	Fault	Tripped Elements	Notes
42	67N BBU 67N-711	breaker fail @ 67N	L7005:67N/3C 67N-T82	
43	67N BBU 67N-712	breaker fail @ 67N	L7018:67N/120H L7005:67N/3C	
44	67N BBU 67N-713	breaker fail @ 67N	L7018:67N/120H 67N-T81	
45	67N L7001 3PH Fault	3ph line fault @ 67N	L7001:67N/120H	
46	67N L7018 3PH Fault	3ph line fault @ 67N	L7018:67N/120H	
47	67N L7003 3PH Fault	3ph line fault @ 67N	L7003:67N/3C	
48	67N L7019 3PH Fault	3ph line fault @ 67N	L7019:67N/91N	
49	67N L7005 3PH Fault	3ph line fault @ 67N	L7005:67N/3C	
50	67N BBU 67N-811	breaker fail @ 67N	L8003:67N/79N 67N-T82	G5/G6 SPS
51	67N BBU 67N-811 T82	breaker fail @ 67N	67N-T82 L8003:67N/79N	G5/G6 SPS
52	67N BBU 67N-813	breaker fail @ 67N	L8002:67N/103H 67N-T81	
53	67N BBU 67N-814	breaker fail @ 67N	L8001:67N/410N 67N-T81	Export SPS: G5/G6
54	67N BKR 67N-814 No Fault	breaker fail @ 67N	L8001:67N/410N 67N-T81	Import SPS
55	67N L8001 3PH Fault	3ph line fault @ 67N	L8001:67N/410N	Export SPS: G5/G6 Import SPS
56	67N L8002 3PH Fault	3ph line fault @ 67N	L8002:67N/103H	
57	67N L8003 3PH Fault	3ph line fault @ 67N	L8003:67N/79N	G5/G6 SPS
58	90H L6008 3PH Fault	3ph line fault @ 90H	L6008:90H/103H	
59	91N BBU 91N-701	breaker fail @ 91N	L7004: 3C/91N L7019: 91N/67N 91N WTG	
60	91N L7004 3PH Fault	3ph line fault @ 91N	L7004: 3C/91N	
61	91N L7019 3PH Fault	3ph line fault @ 91N	L7019:67N/91N	
62	74N L6613 3PH Fault	3ph line fault @ 74N	L6613:1N/81N/74N	
63	74N BBU 74N-613	breaker fail @ 74N	74N substation	
64	108H L6055 3PH Fault	3ph line fault @ 108H	L6055: 108H/132H	
65	4C BBU 4C-621 3PH Fault	breaker fail @ 4C	L6515: 4C/2C L5524: 4C/57C/24C/19C 4C-T2	
66	50N L6503 3PH Fault	3ph line fault @ 50N	L6503: 50N/1N	
67	50N L6507 3PH Fault	3ph line fault @ 50N	L6507: 50N/79N	
68	50N B61 3PH Fault	bus fault @ 50N	L6507: 50N/79N L6511: 50N/93N 50N-T8	TR5 On/Off TR6 On/Off
69	IR669 HV 3PH Fault	bus fault @ IR669	IR669	
70	IR669 LV 3PH Fault	bus fault @ IR669	IR669	
71	IR669 HV 3PH UVRT Fault	bus fault @ IR669	N/A	
72	IR669 LV 3PH UVRT Fault	bus fault @ IR669	N/A	
73	IR669 1N L6613 3PH Fault	3ph line fault @ IR669	L6613:IR669/1N	

ID	Contingency	Fault	Tripped Elements	Notes
74	IR669 74N L6613 3PH Fault	3ph line fault @ IR669	L6613:IR669/74N	
75	DCT 6005][6010	DCT fault	L6005: 120H/131H L6010:120H/90H	
76	DCT 6005][6016	DCT fault	L6005: 120H/131H L6016:120H/137H	
77	DCT 6010][6011	DCT fault	L6010: 120H/90H L6011: 120H/17V	
78	DCT 6033][6035	DCT fault	L6033: 103H/2H/1H L6035: 1H/2H/104H	
79	DCT 6507][6508	DCT fault	L6507: 50N/79N L6508: 50N/79N	50N and 79N ends
80	DCT 6534][7021	DCT fault	L6534: 88S/2S L7021: 88S/101S	
81	DCT 7003][7004	DCT fault	L7003: 3C/67N L7004: 3C/91N	G3 SPS
82	DCT 7008][7009	DCT fault	L7008: 120H/99W L7009: 120H/99W	

3.5.3 Evaluation

PSSE generated output plots for each contingency, with IR669 out of service and in service, are presented in Appendices H through S. For all relevant contingencies, the monitored elements were found to be stable and well-damped.

The full IR669 dynamic model parameters used in these simulations can be found in Appendix B.

Notes are provided in the Appendices where further explanation is necessary. A summary of the notes is provided below:

Table 9: Stability Analysis results

Case	Contingency	Notes
SML_01-2	N/A	N/A
SML_02-2	N/A	N/A
SML_03-2	410N L8001 3PH Fault NSX2 67N BBU 67N-814 NSX2 67N L8001 3PH Fault NSX2	Unstable – N/A as NSX is not armed in this case Unstable – N/A as NSX is not armed in this case Unstable – N/A as NSX is not armed in this case
SML_04-2	410N L8001 3PH Fault NSX2 67N BBU 67N-814 NSX2 67N L8001 3PH Fault NSX2	Unstable – N/A as NSX is not armed in this case Unstable – N/A as NSX is not armed in this case Unstable – N/A as NSX is not armed in this case
SUM_01-2	N/A	N/A
SUM_02-2	410N L8001 3PH Fault G0 67N BKR 67N-814 G0 No Fault 67N L8001 3PH Fault G0 1N L6613 3PH Fault 1N L6503 3PH Fault	IR669 Unstable – N/A as NSX is armed in this case IR669 Unstable – N/A as NSX is armed in this case IR669 Unstable – N/A as NSX is armed in this case 89N-Nuttby WTG tripped offline at t=0.7s (low frequency) 89N-Nuttby WTG tripped offline at t=0.7s (low frequency)
SUM_03-2	410N L8001 3PH Fault G0 410N L8001 3PH Fault NSX1 67N BBU 67N-814 G0 67N BKR 67N-814 G0 No Fault 67N L8001 3PH Fault G0/NSX1	Unstable – N/A as NSX2 is armed in this case IR669 Unstable – NSX2 is armed in this case, system otherwise stable Unstable – N/A as NSX2 is armed in this case Unstable – N/A as NSX2 is armed in this case Unstable – N/A as NSX2 is armed in this case
SUM_04-2	67N BBU 67N-814 NSX2	Unstable – N/A as NSX is not armed in this case

Case	Contingency	Notes
SUM_05-2	410N L8001 3PH Fault NSX2 67N BBU 67N-814 NSX2 67N L8001 3PH Fault NSX2 1N L6613 3PH Fault 1N L6503 3PH Fault	Unstable – N/A as NSX is not armed in this case Unstable – N/A as NSX is not armed in this case Unstable – N/A as NSX is not armed in this case 89N-Nuttby WTG tripped offline at t=3.76s (low frequency) 89N-Nuttby WTG tripped offline at t=3.76s (low frequency)
WIN_01-2	N/A	N/A
WIN_02-2	N/A	N/A
WIN_03-2	410N L8001 3PH Fault G0 410N L8001 3PH Fault NSX1 410N L8001 3PH Fault NSX2 67N BBU 67N-814 G0 67N BBU 67N-814 NSX1 67N BBU 67N-814 NSX2 67N BKR 67N-814 G0 No Fault 67N L8001 3PH Fault G0 67N L8001 3PH Fault NSX1 67N L8001 3PH Fault NSX2 1N L6613 3PH Fault	Unstable – N/A as NSI is armed in this case Unstable – N/A as NSI is armed in this case Unstable – N/A as NSI is armed in this case Unstable – N/A as NSI is armed in this case Unstable – N/A as NSI is armed in this case Unstable – N/A as NSI is armed in this case Unstable – N/A as NSI is armed in this case Unstable – N/A as NSI is armed in this case Unstable – N/A as NSI is armed in this case Unstable – N/A as NSI is armed in this case 89N-Nuttby WTG tripped offline at t=3.76s (low frequency)
WIN_04-2	67N BKR 67N-814 G0 No Fault 1N L6503 3PH Fault	IR669 tripped offline at t=13.2s (multiple FRT) – NSX armed in this case 89N-Nuttby WTG tripped offline at t=3.76s (low frequency)
WIN_05-2	410N L8001 3PH Fault NSX2 67N L8001 3PH Fault NSX2 67N BBU 67N-814 NSX2	Unstable – N/A as NSX is not armed in this case Unstable – N/A as NSX is not armed in this case Unstable – N/A as NSX is not armed in this case

3.6 NPCC-BPS / NERC-BES

At the time of this study, the proposed POI at L-6613 is not categorized as NPCC[2] BPS *(Bulk Power System)* and is categorized as NERC[3] BES *(Bulk Electric System)*.

3.6.1 NPCC-BPS

The BPS testing for the POI bus of IR669 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 IR669 does not have adverse impact outside the local area. The stability test was performed using both the WIN_03-2 and the SML_01-2 cases, representing maximum and minimum expected load levels, with appropriate NS-NB interface flows.

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 IR669 are not classified as NPCC BPS.

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

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

IR669 is categorized as NERC BES, since it meets the fourth of the five inclusion criteria:

- I1: Does not meet: Transformers with the primary terminal and at least one secondary terminal operated at ≥100kV.
- I2: Does not meet: Generating resource(s), including the generator terminals through the high side of the step-up transformer(s), connected at a voltage of ≥100kV.
- I3: Does not meet: Blackstart Resource identified in the Transmission Operator’s restoration plan.
- **I4: Meets: Dispersed power producing resources > 75MVA that are connected through a system designed primarily for delivering this capacity to a common point of connection at > 100kV. The facilities designated as BES are:**
    - **Individual generators**
    - **The collector system and ICIF where-ever the generation aggregates to >75MVA.**
- I5: Does not meet: Static or Dynamic reactive power devices/facilities (excluding generators) connected at >100kV

3.7 Underfrequency Operation

IR669's low frequency ride-through performance was tested by simulating a fault on L-8001 under high import conditions. The NS Import Monitor RAS activates, separating the NS Power grid from the Eastern Interconnection by opening L-6613 between 74N-Springhill and the IR669 POI substation (as modified based on this reports recommendation). The case selected for dynamic simulation was based on Winter Peak, with 300 MW import into Nova Scotia (WIN_03-2).

IR669 remains stable and online as required. Simulation indicates that NS Power's UFLS does activate to stabilize system frequency, shedding a total of 342 MW and 54 MVAR. The simulation results are shown in Figure 9 and Figure 10, as well as Appendix F: *Underfrequency operation*.

Note that values are plotted on 100 MVA system base, so IR669 at 1.0 pu power represents full output of the generators.

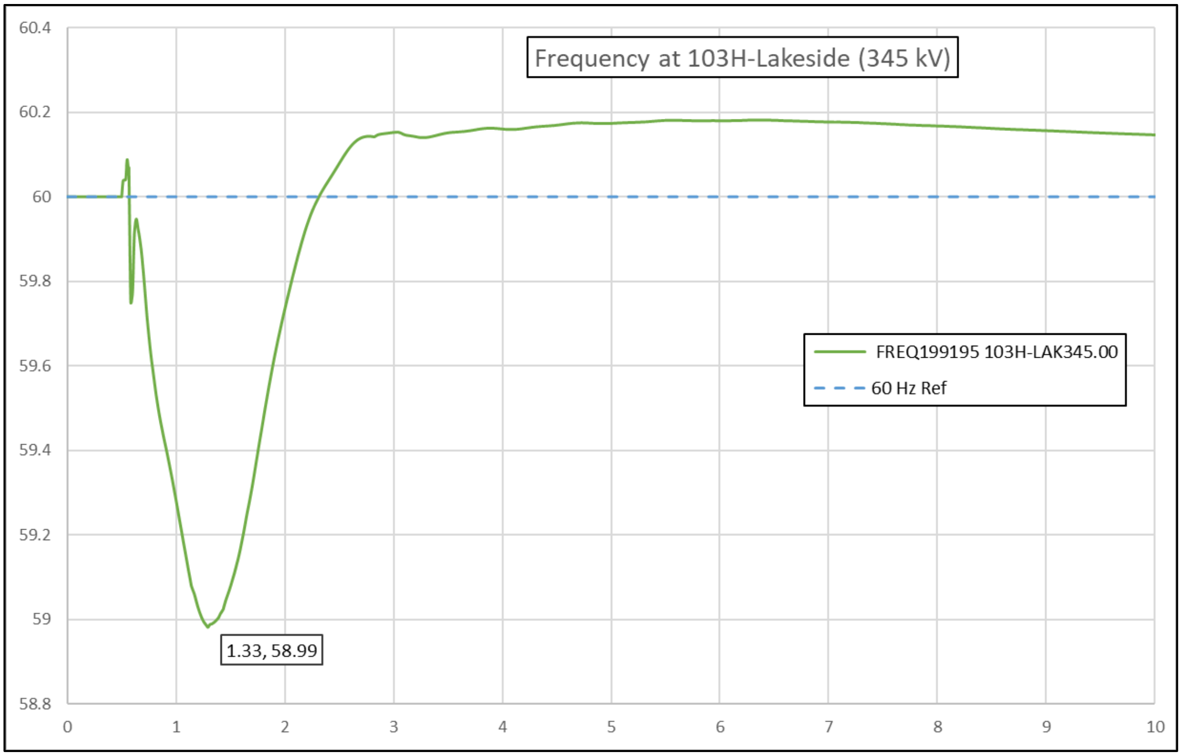


Figure 9: Underfrequency Performance (freq. at 103H-Lakeside)

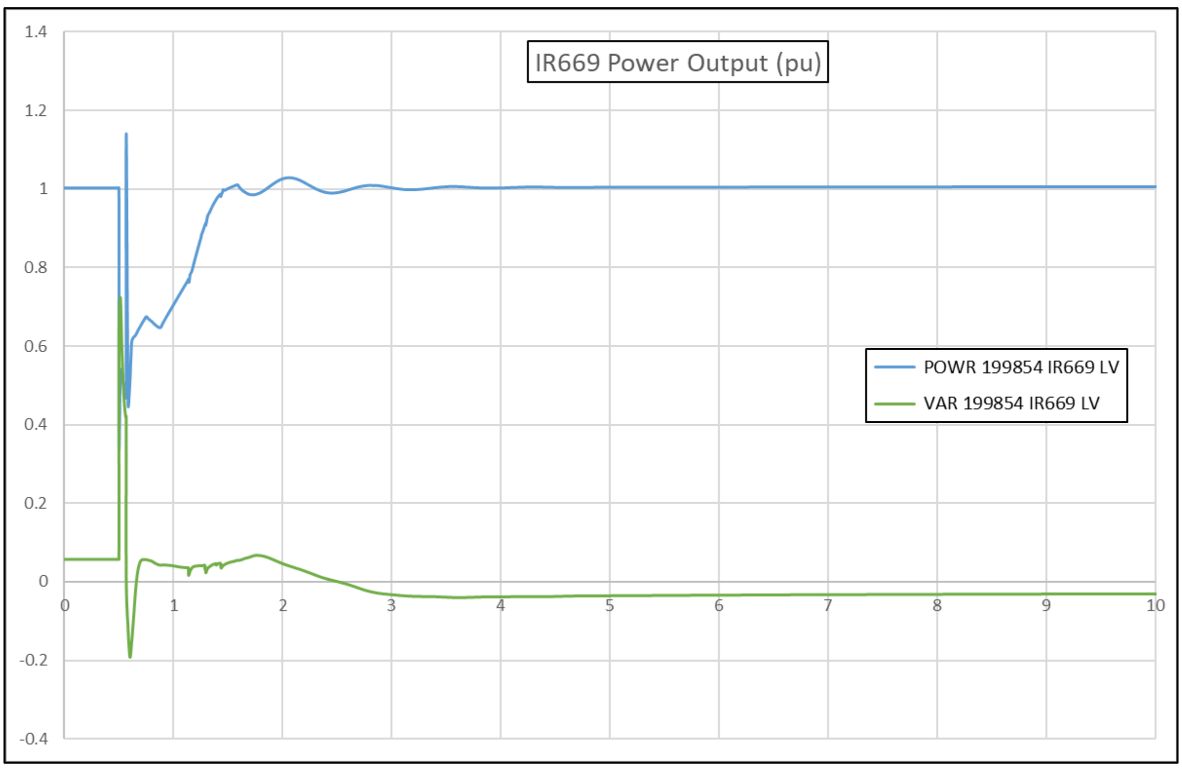


Figure 10: Underfrequency Performance (IR669 machine output)

The simulation result shows that IR669 reduces its output immediately to zero, then gradually ramps up to its pre-fault active power output. While this meets the low frequency ride-through requirement, it does not provide inertial frequency response which is inherently provided by traditional synchronous generators. As more inverter-based generators are added to the NS power system to replace synchronous generators, it is expected that the inverter-based generators will be required to provide the inertial frequency response in the form of fast frequency response or by other means, such as synchronous condenser, FACTS devices, etc. This topic will be studied in the SIS Part 2 EMT study.

3.8 Voltage Ride-through

A 3-phase fault for 9 cycles, simulating a Transmission System fault, was applied to IR669's 138kV and 34.5kV buses to test the WTG facility's Low Voltage Ride-through (LVRT) capability.

The stability plot in Figure 11 and Figure 12 demonstrates that IR669 rides through the fault and stays online in both cases, as required. Results are shown in Appendix G: *Low voltage ride-through.*

While this test demonstrates that IR669 meets the LVRT requirement, it does not provide inertial frequency response, as discussed in the previous section. This topic will be studied in the SIS Part 2 EMT study.

Note that values are plotted on 100 MVA system base, so IR669 at 1.0 pu power represents full output of the generators.

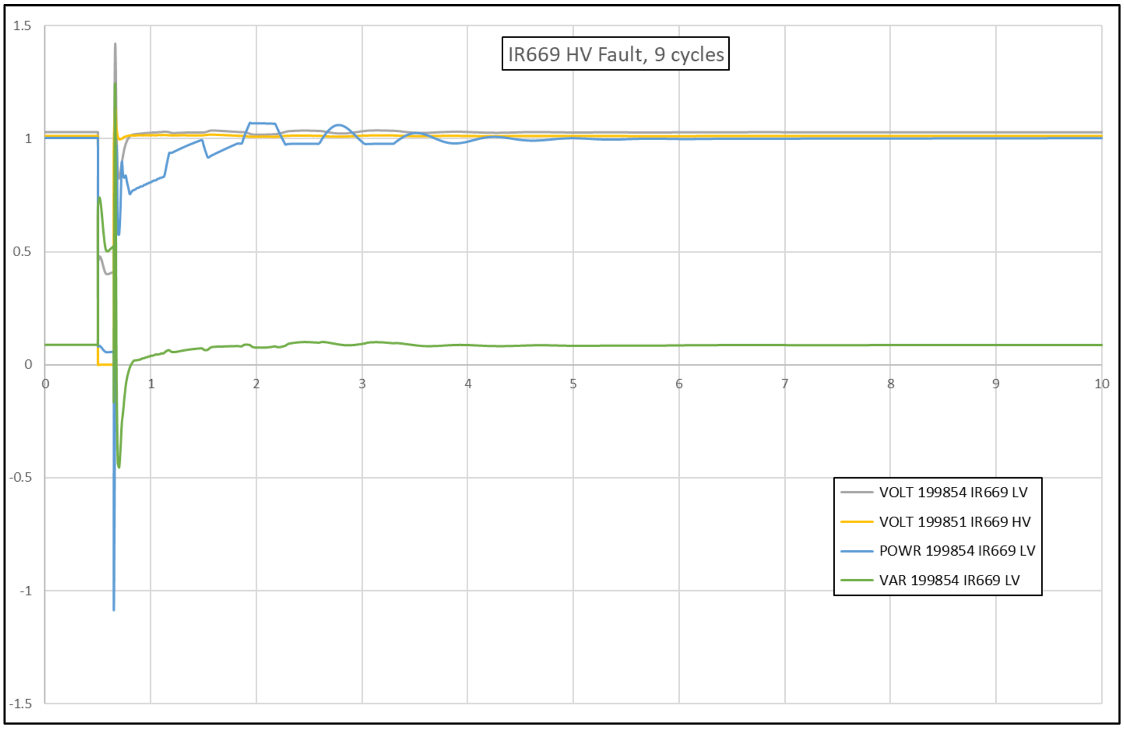


Figure 11: IR669 LVRT Performance (HV fault, 9 cycles)

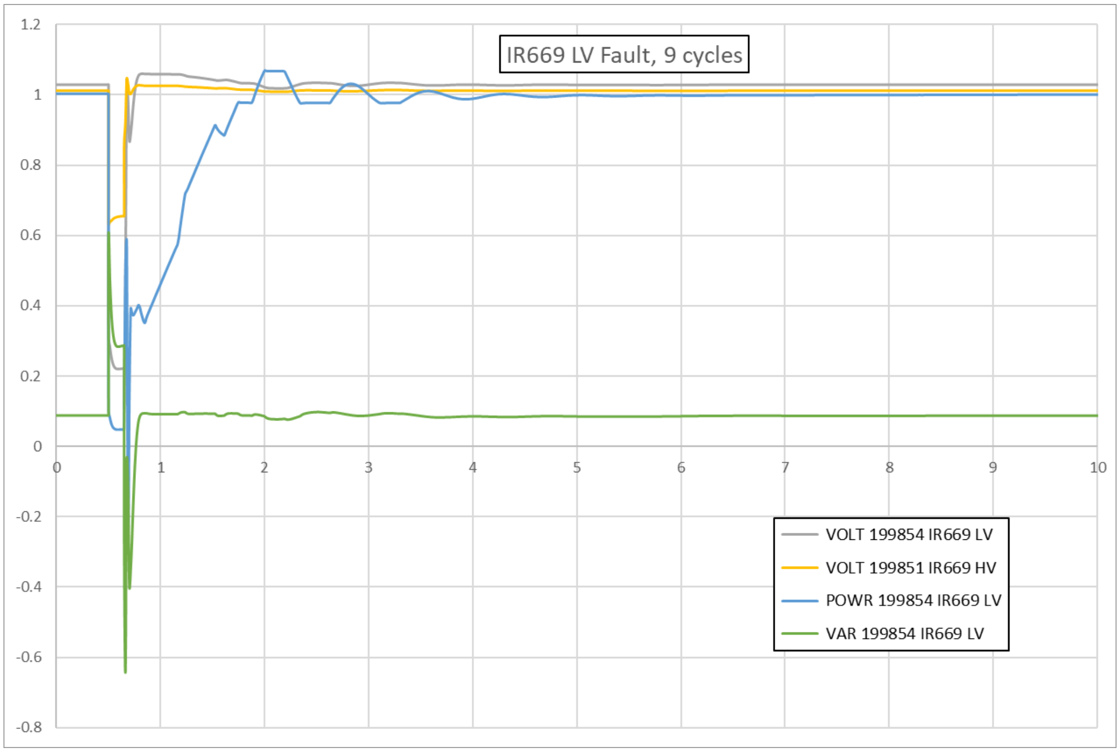


Figure 12: IR669 LVRT Performance (LV fault, 9 cycles)

3.9 Loss Factor

With IR669 in service, the loss factor is calculated as 6.9% when accounting for the ICIF losses and 4.3% when ignoring the ICIF losses. The data and calculation is detailed in Table 10: *IR669 loss factor data* and Equation 1: *IR669 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, while a positive loss factor reflects an increase in system losses.

Table 10: IR669 loss factor data

Loss Factor	Including ICIF Losses	Excluding ICIF Losses
IR669 nameplate	100.3	100.3
TC3 w/ IR669	49.6	47.1
TC3 w/o IR669	143.1	143.1
Delta	6.9	4.3
2026 loss factor	6.9%	4.3%

Equation 1: IR669 loss factor calculation

$$loss\ factor = \frac{(IR669_{nameplate} + TC3_{\frac{w}{}IR669}) - TC3_{\frac{w}{o}IR669}}{IR669_{nameplate}}$$

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 11.

The following facilities are required to interconnect IR669 to the NSPI system via the 138 kV line L-6613 between 1N-Onslow and 74N-Springhill as NRIS:

1) **Network upgrades:**
   a) Three breaker ring bus, 138 kV substation at the POI along L-6613 with P&C acceptable to NSPI. Substation design will meet applicable NERC and NPCC requirements. The IC is responsible for obtaining the land and access for this new substation.
   b) Protection & control modifications at 1N-Onslow and 74N-Springhill to accommodate the IR669 substation.

c) NS Import Monitor RAS modifications at 1N-Onslow and 74N-Springhill. Upon activation of the NS Import Monitor RAS, L-6613 will be opened at the IR669 POI substation, or at 74N-Springhill to maintain IR669's electrical connection to the NS island system. Additions/modifications to RAS are subject to NPCC approval.

d) Install 2 km of OHGW *(Overhead Ground Wire)* along L-6613, centered on the IR669 POI. The existing line L-6613 is only equipped with OHGW for 1 km at the 1N-Onslow approach and for 1 km at the 74N-Springhill approach.

2) Transmission Provider's Interconnection Facilities (TPIF):

a) Construct a 138 kV transmission line, with OHGW *(Overhead Ground Wire)* & OPGW *(Optical Ground Wire)*, approximately 2.75 km long, built to NSPI standards from the IR669 POI substation.

b) Protection, 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) Facilities to provide rated dynamic reactive power during the full range of active power production.

b) 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.

c) NSPI to have supervisory 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.

d) 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 be capable of reacting to continuous control signals from the NSPI SCADA system's Automatic Generation Control (AGC) system to control tie-line fluctuations as required.

e) 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.

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

g) 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.

h) Operation at ambient temperatures as low as -30ºC. The IC shall 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 IR669's Network Resource Interconnection Service is shown in Table 11: NRIS cost estimate. This estimate assumes there is adequate space for new equipment and modifications.

Table 11: NRIS cost estimate

Transmission Provider Interconnection Facilities (TPIF) Upgrades		
i.	Spur line from POI to IR669 substation (~2.75 km)	$ 1,650,000
ii.	P&C relaying equipment	$ 165,000
iii.	Teleprotection & SCADA communications	$ 150,000
iv.	NSPI supplied RTU	$ 65,000
	Subtotal:	$ 2,030,000

Network Upgrades (NRIS)		
i.	Three breaker ring bus, 138 kV substation with P&C and connection to L-6613	$ 6,250,000
ii.	NS Import Monitor RAS modifications at 1N and 74N, subject to NPCC approval	$ 250,000
iii.	P&C modifications at 1N-Onslow and 74N-Springhill	$ 500,000
	Subtotal:	$ 7,000,000

Determined Costs	
Network Upgrades + TPIF Upgrades	$ 9,030,000
Contingency (10%)	$ 900,000
Total of Determined Cost Items (Excluding HST)	$ 9,930,000
To Be Determined Cost Items	
System additions as identified in SIS Part 2 (EMT Analysis)	TBD

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 and the Part 2 System Impact Study (EMT) 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.

Short circuit analysis calculated the minimum SCR at the low side of IR669's substation step down transformer as 4.0 (396 MVA / 100.3 MW) with all transmission elements in service and 2.6 (259 MVA / 100.3 MW) with L-6613 between 1N and IR 669 out of serviceThis information should be provided to Nordex for design specification. Note that per the NSPI TSIR Section 7.4.15, as the system short circuit level declines over time with changes to transmission configuration and generation mix, the Generating Facility must be able to accommodate these changes.

IR669 does not meet the 0.95 lagging power factor requirement based on the supplied transformer information and assumed collector circuit impedance. As well, IR669 is unable to provide rated reactive power at the zero-power operating point. Additional dynamic reactive power compensation will therefore be required to inject reactive power to achieve 0.95pu power factor measured at the high side of the ICIF transformer, as well as to provide rated reactive power at the zero-power operating point. IR669 does not meet the requirement to provide rated reactive power through the full range of real power output, from zero to full power, even with the optional STATCOM option. Additional dynamic reactive power compensation will therefore be required.

IR669 meets NS Power’s required continuous voltage flicker requirements under normal system conditions based on the supplied test data. The continuous voltage flicker emission, Plt, can exceed 0.25 for the minimum generation case with L-6613 between Onslow and IR669 out of service. Should this cause an issue with other NS Power Customers, IR669 would be curtailed for the duration of the contingency event.

IR669 is designated as NERC BES based on the BES inclusion criteria. The facilities associated with IR669 are not designated as NPCC BPS at this time. However, as this facility will be connected to an existing BPS line (Category A Interconnection), it is recommended that the new three breaker ring bus substation be designed to BPS standards.

The addition of IR669 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 IR669.

NS Import Monitor RAS requires modifications at 1N-Onslow and 74N-Springhill due to the addition of IR669. Upon activation of the NS Import Monitor RAS, L-6613 will be opened at the IR669 POI substation, or at 74N-Springhill in order to maintain IR669’s electrical connection to the NS island system. Additions/modifications to RAS are subject to NPCC approval.

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.

An EMT (Electromagnetic Transient) study will also be completed as a Part 2 to this SIS. The Part 2 SIS EMT study will progress in parallel with the next phase of the GIP process (Facilities Study). The outcomes of the Part 2 work will be captured as an addendum to the Part 1 SIS report and may trigger restudy for facilities study work completed at that time.

5.2 Summary of Expected Facilities

To accommodate the full output of IR669, a new 138 kV substation is required at the POI along L-6613, plus approximately 2.75 km of new 138 kV transmission line between the POI and ICIF. 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 $9,930,000 (excl. taxes). 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.

Appendix A: Transmission line ratings

NSPI Transmission Line Ratings

Last Updated: 2023-02-09

LINE	STATION	CONDUCTOR Type	Maximum Operating Temp. (Celsius)	SUMMER RATING 25 DEG (MVA)	WINTER RATING 5 DEG (MVA)	BREAKER 100% Name-plate	SWITCH 100% Name-plate	CURRENT TRANSFORMER RELAYING Ratio	RELAYING R.F.	RELAYING MVA	FULL SCALE METERING Ratio	METERING R.F.	METERING MVA	TRIP MVA
L-8001	Memramcook NB	ACSR 2x795 Drake	49	670	1021						1200	1	831	
	67N Onslow EHV					1791	1194	800	2	956	800	1	554	1851
L-8002	67N Onslow EHV	ACSR 2x795 Drake	49	670	1021	1791	1194	800	2	956	800	1	554	2291
	103H Lakeside					1194	1194	800	2	956	800	1	554	3093
L-8003	79N Hopewell	ACSR 2x1113 Beamou nt	120	1372	1832	1791	1791	1200	2	1434	1200	2	831	4731
	67N Onslow EHV					1791	1194	1200	1.67	1195	1200	2	831	3075
L-7001	67N Onslow EHV	ACSR 795 Drake	60	298	383	797	797	500	2	398	1000	1	462	533
	120H Brushy Hill					797	797	800	2	637	1200	1	554	1065
L-7002	67N Onslow EHV	ACSR 795 Drake	100	447	506	797	797	800	2	637	1000	1	462	1065
	120H Brushy Hill					797	797	800	2	637	1200	1	577	1065
L-7003	3C Pt. Hastings EHV	ACSR 556 Dove	60	233	307	797	797	500	2	398	1000	1	462	533
	67N Onslow EHV					797	797	500	2	398	1000	1	462	468
L-7004	3C Pt. Hastings EHV	ACSR 556 Dove	60	233	307	797	797	500	2	398	1000	1	462	533
	91N Dalhousie Mountain					797	797	800	2	600	800	1	368	600

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Last Updated: 2023-02-09

LINE	STATION	CONDUCTOR Type	Maximum Operating Temp. (Celsius)	SUMMER RATING 25 DEG (MVA)	WINTER RATING 5 DEG (MVA)	BREAKER 100% Name-plate	SWITCH 100% Name-plate	CURRENT TRANSFORMER RELAYING Ratio	RELAYING R.F.	RELAYING MVA	FULL SCALE METERING Ratio	METERING R.F.	METERING MVA	TRIP MVA
L-7005	3C Pt. Hastings EHV	ACSR 1113 Beaumont	70	404	502	797	797	500	2	398	1000	1	462	533
	67N Onslow EHV					797	797	500	2	398	1000	1	462	533
L-7018	67N Onslow EHV	ACSR 2x795 Drake /AACSR 2156	49	375	589	797	797	800	2	637	800	2	462	1633
	120H Brushy Hill					797	797	800	2	637	1000	2	462	1693
L-7019	91N Dalhousie Mountain	ACSR 556 Dove	70	273	345	797	797	800	2.5	797	800	2.5	637	600
	67N Onslow EHV					797	797	800	2	637	1000	2	462	469
L-6001a	1N Onslow	ACSR 556.5 Dove	60	140	184	598	287	800	1.5	287	800	1	231	456
	82V Elmsdale						287				NA			
L-6503b	51N Michelin Granton	ACSR 1113 Beaumont	85	287	335		404				NA			
	1N Onslow					478	287	1200	2.5	717	1200	1	665	449
L-6535	Memramcook NB	ACSR 556.5 Dove	100	213	242	478	359			359	1200	1	346	940
	92N Amherst Wind Farm					287	287	800	2	382	800	2	441	590
L-6536	74N Springhill	ACSR 556.5 Dove	100	213	242	478	287	600	2	287	1200	1	331	724
	Memramcook NB					478	359			359	1200	1	346	510

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NSPI Transmission Line Ratings Last Updated: 2023-02-09

LINE	STATION	CONDUCTOR Type	Maximum Operating Temp. (Celsius)	SUMMER RATING 25 DEG (MVA)	WINTER RATING 5 DEG (MVA)	BREAKER 100% Name-plate	SWITCH 100% Name-plate	CURRENT TRANSFORMER RELAYING Ratio	R.F.	MVA	FULL SCALE METERING Ratio	R.F.	MVA	TRIP MVA
L-6514	74N Springhill	ACSR 556.5 Dove	60	140	184	287	287	600	2	287	600	1	173	617
	30N Maccan					287	143	600	2.5	358	600	1	173	820
L-6613	1N Onslow	ACSR 1113 Beaumont	100	320	363	478	287	800	2	382	1200	2	332	522
	74N Springhill					478	287	1200	2.5	717	1200	2	332	357