Interconnection Feasibility Study Report
GIP-IR645-FEAS-R0

Generator Interconnection Request 645
102.6 MW Wind Generation Facility
Melvin Lake, NS

2022-03-31

Control Centre Operations
Nova Scotia Power Inc.

Executive Summary

This Feasibility Study report (FEAS) presents the results of a Feasibility Study Agreement for the connection of a 102.6 MW Wind Turbine Generation (WTG) facility interconnected to the NSPI system as Network Resource Interconnection Service (NRIS), with Energy Resource Interconnection Service (ERIS) as an option.

This project is listed as Interconnection Request #645 in the NSPI Interconnection Request Queue and will be referred to as IR645 throughout this report. The proposed Commercial Operation Date is 2023/12/1.

The Interconnection Customer (IC) identified the 138 kV transmission line L6004 (which runs from the 90H-Sackville substation to the 101V-MacDonald Pond substation) as the primary Point of Interconnection (POI). Based on the WTG site coordinates provided, the POI is proposed as approximately 20 km from the 90H substation. The facility will be interconnected to the POI via a 4.4 km, 138 kV transmission line from the Point of Change of Ownership (PCO).

There is one relevant long-term firm Transmission Service Request (TSR) that has established Queue position and is at the System Impact Study (SIS) stage, with a requested in-service date of 2025/01/01. This request, TSR411, is expected to alter the configuration of the Transmission System in Nova Scotia. As a result, the following notice has been posted to the OASIS site[1]:

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

The system upgrades resulting from this TSR study are not expected to greatly influence the results of IR645, as it is connected near the Halifax Area and is electrically close to the load centre with minimal transmission system impact.

Based on the information provided by the IC, this feasibility assessment presents the following findings:

[1] OASIS Generation Interconnection Procedures; https://www.nspower.ca/oasis/generation-interconnection-procedures

- There are no concerns regarding increased short circuit levels. The increase in short circuit level remains within the capability of associated breakers. The minimum three phase short circuit level at the Interconnection Facility's (IF) low side bus is 504 MVA with IR645 and all transmission system elements in service.
- Voltage flicker will be examined when data is made available for the SIS.
- The project design must meet the NSPI Transmission System Interconnection Requirements (TSIR)[2].
- The power flow analysis identified one contingency that violates thermal loading criteria while generating at full output in some operating conditions. Network upgrades required to alleviate this loading violation are proposed for NRIS operation. Conditions where IR645 output will be restricted are also outlined for ERIS operation.
- Supplementary reactive power support for IR645 is required as it is unable to meet NSPI's ±0.95 net power requirements at the IF 138 kV bus. This is in situations when the wind facility is operating near maximum active power output and full reactive power is required. Supplementary reactive power support will be further investigated in the SIS.
- Since IR645 meets the NERC definition of Bulk Electric System (BES), the high side interconnection with the 138 kV bus would also be considered BES. There is the potential for an exclusion from BES to be granted for the high side (138kV) bus based on further analysis per the NS BES Exception Procedure. This analysis will be initiated as part of the SIS and exclusion from BES will only be granted upon subsequent approval by the NS Utility and Review Board (UARB).
- The preliminary loss factor is calculated as 1.0% while generating onto the 138 kV POI on L6004, net of any losses on the IC facilities up to the POI.

The present preliminary non-binding cost estimate for interconnecting IR645 to the 138 kV line L6004:

- As a Network Resource: $8,590,000 ($3,600,000 for Network Upgrades, $4,210,000 for TPIF, 10% contingency adder).
- As an Energy Resource: $5,180,000 ($500,000 for Network Upgrades, $4,210,000 for TPIF, 10% contingency adder).

This does not include any To Be Determined costs associated with the SIS. This estimate will be further refined in the SIS and Facilities (FAC) studies.

Note that the proposed transmission path from the POI to PCO requires more detailed engineering to provide a more accurate cost estimate. It is the customers responsibility to provide suitable land, right of way, and access roads for the POI substation and spur line to the ICIF. The right of way shall be registered in NSPI’s name.

The estimated time to construct the Network Upgrades and TPIF after the receipt of funds is 24-36 months for NRIS operation and 18-24 months for ERIS operation.

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[2] NS Power Transmission System Interconnection Requirements; https://www.nspower.ca/oasis/standards-codes

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1.0 Introduction

This Feasibility Study report (FEAS) presents the results of a Feasibility Study Agreement for the connection of a 102.6 MW Wind Turbine Generation (WTG) facility interconnected to the NSPI system as Network Resource Interconnection Service (NRIS), with Energy Resource Interconnection Service (ERIS) as an option.

This project is listed as Interconnection Request (IR) #645 in the NSPI Interconnection Request Queue and will be referred to as IR645 throughout this report. The proposed Commercial Operation Date is 2023/12/1.

The Interconnection Customer (IC) identified the 138 kV transmission line L6004 (which runs from the 90H-Sackville substation to the 101V-MacDonald Pond substation) as the primary Point of Interconnection (POI). Based on the WTG site coordinates provided, the POI is proposed as approximately 20 km from the 90H substation. The facility will be interconnected to the POI via a 4.4 km, 138 kV transmission line from the Point of Change of Ownership (PCO). Figure 1 shows the approximate location of the proposed IR645 site.

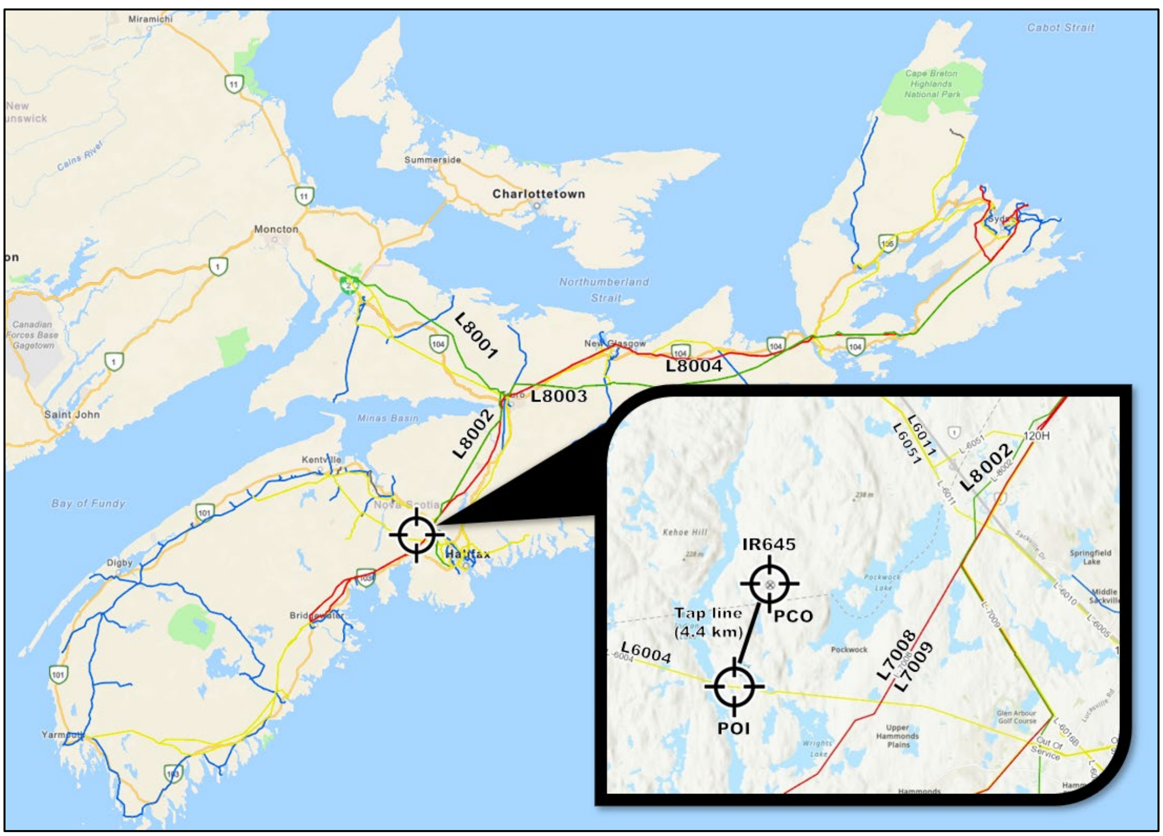

Figure 1: IR645 approximate geographic location

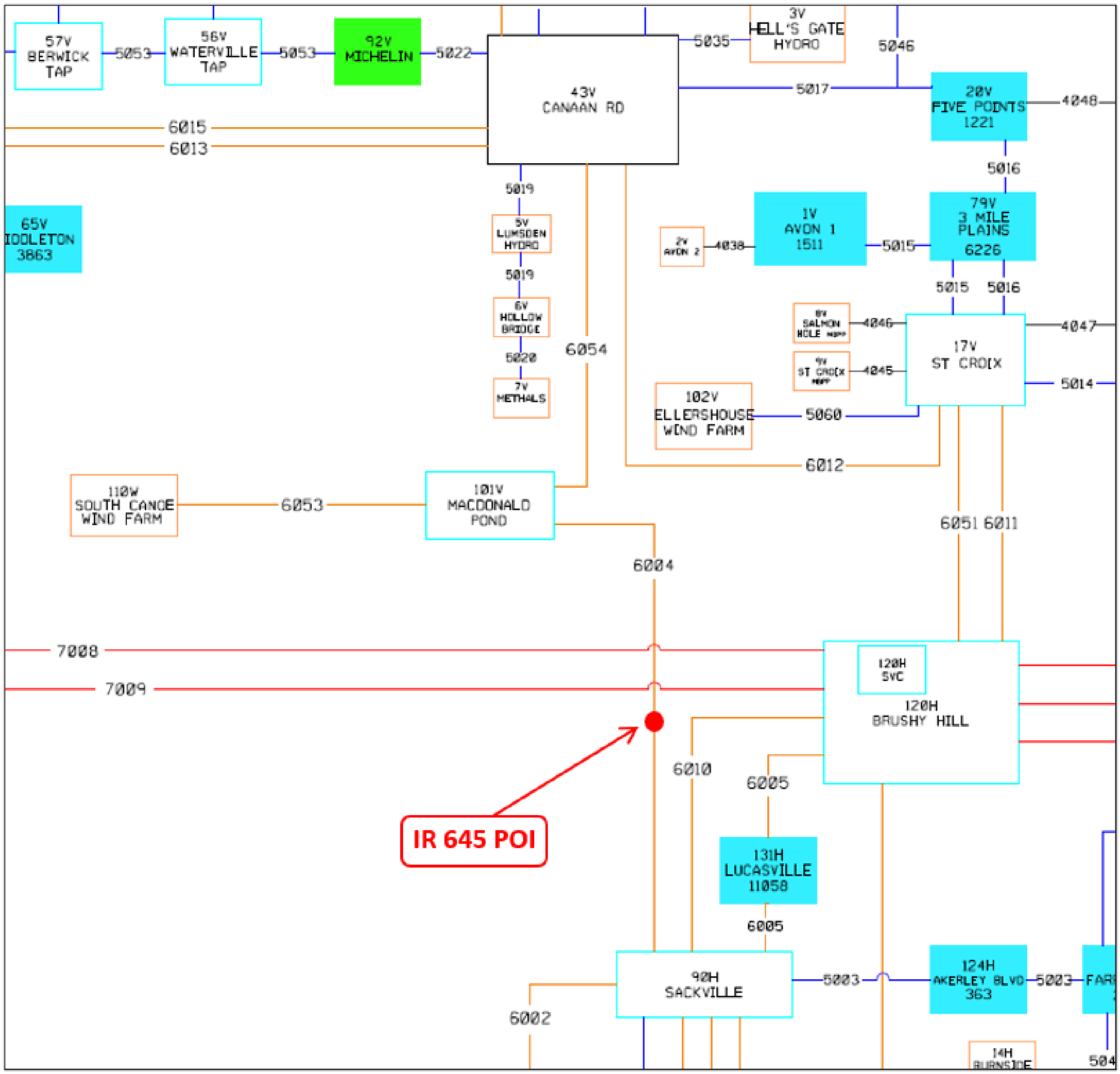

Figure 2: IR645 Point of Interconnection

2.0 Scope

This Interconnection Feasibility Study's (FEAS) objective is to provide a preliminary evaluation of system impact and a high-level non-binding cost estimate of interconnecting the new WTG facility to the NSPI Transmission System at the designated location based on single contingency criteria. This assessment will identify potential impacts on transmission element loading, which must remain with their thermal limits. Any potential voltage criteria violations will be identified and addressed. Circuit breakers must be upgraded if the proposed facility increases the short-circuit duty of any circuit breakers beyond their rated capacity.

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

- Identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection and any Network Upgrades necessary to address the short circuit issues associated with the IR.
- Identification of any thermal overload or voltage limit violations resulting from the interconnection and identify the necessary Network Upgrades to allow full output of the proposed facility.
- Description and high-level non-binding estimated cost of and time to construct the facilities required to interconnect the generating facility to the transmission system.

This FEAS does not include a complete determination of facility changes/additions required to increase the system transfer capabilities that may be required to the transmission system to meet the design and operating criteria established by NSPI, the Northeast Power Coordinating Council (NPCC), and the North American Electric Reliability Corporation (NERC). These requirements will be determined by a more detailed analysis in the subsequent interconnection System Impact Study (SIS). An Interconnection Facilities Study (FAC) follows the SIS in order to ascertain the final cost estimate to the interconnect the generating facility.

3.0 Assumptions

This FEAS is based on technical information provided by the IC. The POI and configuration are studied as follows:

1. NRIS and ERIS will be studied per the IR645 Feasibility Study agreement and section 3.2 of the Generation Interconnection Procedures (GIP).
2. Commercial Operation date: 2023/12/1.
3. The Interconnection Facility consists of 18 x 5.7 MW Nordex N149 wind turbine generator units (type 3 – doubly-fed induction generator [DFIG]), capped at 102.6 MW. Each WTG is connected via one of five 34.5 kV collector circuits to the 90/115 MVA substation step-up transformer.
4. The IC identified the transmission line L6004 (90H-Sackville to 101V-MacDonald Pond) as the primary POI. Based on the WTG site coordinates provided, the POI is proposed as approximately 20 km from the 90H substation.
5. The IC Interconnection Facilities (ICIF) will be interconnected to the POI via a 4.4 km, 138 kV transmission line from the POI to the PCO. The connection to L6004 will require a single breaker line tap with protection, in accordance with Table 8 of NSPI’s Transmission System Interconnection Requirements.

   Note: The coordinates provided by the IC indicate a direct distance of 4.4 km from the closest intersection with L6004. If the actual spur line length required will exceed 4.7 km in length, a 3-breaker ring bus will be required at the POI.

6. This study uses 556.5 ACSR Dove rated at 100ºC for the 4.4 km transmission line between the POI and the IC substation.
7. Preliminary data provided by the IC for the substation step-up transformer and padmount transformers:
   7.1. The substation step-up transformer was modelled as a 138 kV–34.5 kV transformer rated at 90/115 MVA, with a positive sequence impedance of 13% and zero sequence impedance of 10% at 90 MVA. It has a winding configuration of Grounded Wye (HV) – Delta (LV). An X/R ratio of 37 was specified for this unit.

   7.2. The generator step-up transformers were modelled as an equivalent transformer based on 18 (eighteen) 34.5 kV - 0.75 kV 6.35 MVA transformers, each with an assumed 10% positive sequence impedance and 8.5% zero sequence impedance and X/R ratio of 12. The winding configuration was given as Delta (HV) – Grounded Wye (LV).
8. A generic collector circuit impedance is assumed since a detailed collector circuit design was not provided. Note that the plant's net real and reactive power will be impacted by losses through the transformers and collector circuits.
9. The FEAS 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 that have a System Impact Study in progress will proceed, as listed in Section 4.0: Project Queue Position.
10. It is the IC's responsibility that the new facility will meet all requirements of NSPI's GIP and NSPI's Transmission System Interconnection Requirements.
11. The transmission line L6004 between 90H-Sackville and 101V-MacDonald Pond is 47.4 km long, comprised entirely of 556.5 ACSR Dove rated at 75C.
12. Ratings of transmission lines in the vicinity of IR645 are as follows:

NSPI Transmission Line Ratings — Last Updated: 2021-08-27

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-6005	120H Brushy Hill	ACSR 795 Drake	100	268	304	478	478	800	2	382	1200	1	346	1762
	90H Sackvillle					287	287	800	2	382	1200	1	346	1523
L-6010	120H Brushy Hill	ACSR 795 Drake	100	268	304	478	478	800	2	382	1200	1	346	1708
	90H Sackville					287	287	600	2	287	1200	1	346	1880

L-6011	120H Brushy Hill	ACSR 556.5 Dove	100	215	242	478	478	800	2	382	800	1	231	670
	17V St. Croix					287	287	600	2	287	600	1	173	1171
L-6016	120H Brushy Hill	ACSR 1113 Beaumont	70	242	301	478	478	800	2	382	1200	1	346	1323
	103H Lakeside					287	478	800	2	382	800	1	231	1093
L-6051	120H Brushy Hill	ACSR 795 Drake	100	268	304	478	478	800	2	382	800	1	231	865
	17V St. Croix					287	287	800	2	287	800	2	231	456
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-7008	120H Brushy Hill	ACSR 1113 Beaumont	70	404	502	797	797	800	2	478	1200	1	554	1235
	99W Bridgewater EHV					797	797	500	2	398	1000	1	462	1235
L-7009	120H Brushy Hill	ACSR 795 Drake	50	223	340	797	797	800	2	637	1200	1	577	901
	99W Bridgewater EHV					996	797	500	2	398	1200	1	577	751
L-7018	67N Onslow EHV	ACSR 2x795 Drake /AACSR 2156	60	506	675	797	797	800	2	637	800	1.25	462	1441
	120H Brushy Hill					797	797	800	2	637	1000	1	462	1441

Table 1: Transmission line ratings

4.0 Project Queue Position

All in-service generation is included in this FEAS. As of October 15, 2021, the following projects are higher queued in the Advanced Stage Interconnection Request Queue and are included in this study's base cases. Figure 3 shows the GIP queue which applies to all Rate Base RFP (Request For Proposal) feasibility studies currently underway.

Combined T/D Advanced Stage Interconnection Request Queue

Publish Date: *Friday, October 15, 2021*

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	01/09/2018	GIA Executed	NRIS	N/A
2 -T	516	05-Dec-14	Cumberland	5	5	37N	Tidal	01-Jul-16	31/05/2020	GIA Executed	NRIS	N/A
3 -T	540	28-Jul-16	Hants	14.1	14.1	17V	Wind	01-Jan-18	31/10/2023	GIA Executed	NRIS	N/A
4 -T	542	26-Sep-16	Cumberland	3.78	3.78	37N	Tidal	01-Jan-19	01/11/2021	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 -D	569	26-Jul-19	Digby	0.6	0.6	509V-302	Tidal	01-Mar-21	30/07/2021	GIA Executed	N/A	N/A
7 -D	568	21-May-19	Cumberland	2	2	22N-404	Solar	01-Sep-20	01/09/2021	GIA Executed	N/A	N/A
8 -D	566	16-Jan-19	Digby	0.7	0.7	509V-301	Tidal	31-Jul-19	29/01/2021	GIA Executed	N/A	N/A
9 -T	574	27-Aug-20	Hants	58.8	58.8	L-6051	Wind	30-Jun-23		FAC Complete	NRIS	N/A
10-D	595	11-Mar-21	Halifax	0.1	0.1	1H-454	Battery	11-Jan-21		SIS Complete	N/A	N/A
11-T	598	13-May-21	Cumberland	2.52	2.52	37N	Tidal	01-Dec-22		SIS in Progress	NRIS	N/A
12-D	604	07-Jun-21	Cape Breton	0.45	0.45	11S-303	Solar	15-Jan-22		SIS in Progress	N/A	N/A
13-D	603	31-May-21	Cumberland	0.4	0.4	22N-404	Solar/Battery	16-Feb-22		SIS in Progress	N/A	N/A
14-D	600	27-May-21	Halifax	0.6	0.6	99H-312	Solar/Battery	02-Mar-22		SIS in Progress	N/A	N/A
		Totals:		139.65	139.65							

Figure 3: GIP Queue

The following projects in Figure 4 below are included in the Transmission Service Request (TSR) Queue as of January 22, 2022:

OATT Transmission Service
Queued System Impact Studies
Active January 22, 2022

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, 2025	550	SIS in Progress
3	TSR 412	January 19, 2021	Point-to-point	Woodbine - NS	January 1, 2025	500	Withdrawn

*Indicates project as being located near provincial border.

Figure 4: TSR Queue

Regarding TSR 411, it is expected to be in service in 2025 and system studies are currently underway to determine the required upgrades to the Nova Scotia transmission system. As a result, the following notice has been posted to the OASIS site[3]:

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

5.0 Short Circuit

IR645 will not impact the nearby 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, LG, and 3LG faults.

The interrupting capability of the neighbouring 138 kV circuit breakers is at least 5000 MVA. Short circuit levels with and without IR645 are provided in Tables 2 and 3.

Table 2: Maximum Short circuit levels in MVA

Maximum Generation: All Generation On, All Transmission Lines In Service		
Measured Bus	***With IR645 (MVA)***	***Without IR645 (MVA)***
POI on L6004 (138 kV)	1722	1634
90H-Sackville (138 kV)	3834	3764
101V-MacDonald Pond (138 kV)	1313	1285
IR645 ICIF (34.5 kV)	566	462

[3] OASIS Generation Interconnection Procedures; https://www.nspower.ca/oasis/generation-interconnection-procedures

Table 3: Minimum Short circuit levels in MVA

Minimum Generation: PA, ML, LG1, TR6 On, All Transmission Lines In Service		
Measured Bus	***With IR645 (MVA)***	***Without IR645 (MVA)***
POI on L6004 (138 kV)	1151	1063
90H-Sackville (138 kV)	1839	1760
101V-MacDonald Pond (138 kV)	879	840
IR645 ICIF (34.5 kV)	504	401
Minimum Generation: L6004 Open at 101V		
POI on L6004 (138 kV)	946	857
IR645 ICIF (34.5 kV)	471	368
Minimum Generation: L6004 Open at 90H		
POI on L6004 (138 kV)	430	342
IR645 ICIF (34.5 kV)	327	224

Further short circuit analysis will be performed in the SIS and will also examine Short Circuit Ratio (SCR) under minimum short circuit level conditions.

6.0 Voltage Flicker & Harmonics

Voltage flicker will be examined when data is made available for the SIS, as the information was not provided at the time of this study. A summary of NS Power's voltage flicker requirements is listed in Table 4: Flicker requirements.

Table 4: Flicker requirements

	P_{st}	P_{lt}
NS Power's requirements	≤ 0.25	≤ 0.35

The WTG facility must meet IEEE Standard 519-2014 limiting voltage Total Harmonic Distortion *(all frequencies)* to no higher than 1.5% with no individual harmonic exceeding 1.5% on 138 kV.

7.0 Load Flow Analysis

Power flow analysis was performed for generation dispatches under system light load, summer peak load, and winter peak load conditions. Dispatch was selected to represent import and export scenarios with New Brunswick for various flows associated with the existing Maritime Link transmission service reservation. These include exports to NB of up to 330 MW between March 1st and November 30th, and exports of 150MW to NB for the period from December 1st to February 28th. These represent flows under normal system conditions. In the event of a contingency in New Brunswick, NSPI must provide an additional 168 MW of supply. As well, in the event of a contingency in Nova Scotia, New Brunswick is obligated to provide up to 142.5 MW of generation to NS.

IR645 is located to the west of Halifax, connected via 138 kV transmission line L6004 which runs from 90H-Sackville to the 101V-MacDonald Pond substation. IR645 is most notably impacted by the Western Valley Import corridor which defines the interface flows from the Halifax area to the Valley. More directly, the flow on transmission lines L6004 and L6054 are determined by the amount of generation at the 110W-South Canoe Lake wind generation site.

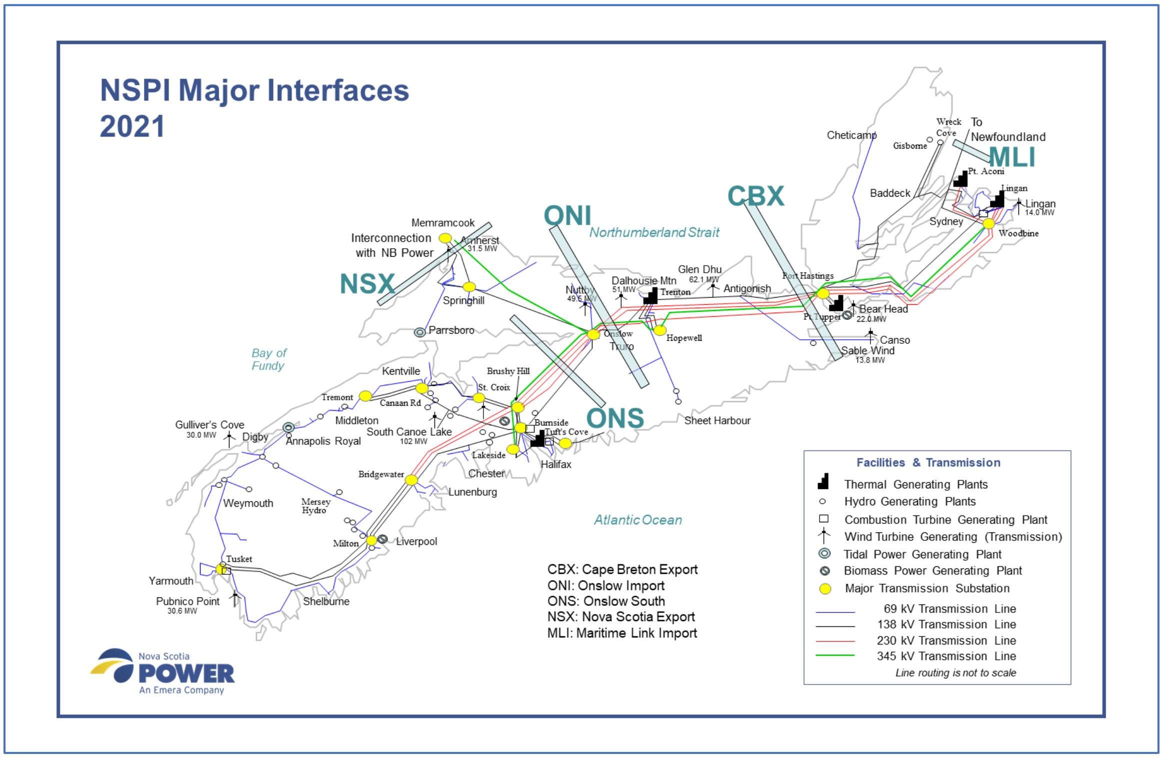

Figure 5: NSPI Major Interfaces

7.1 Base Cases:

The base cases used in this study are shown in Table 5: Base Case Dispatch. For these cases:

- Transmission connected wind generation facilities were dispatched between 22% and 100% of their rated capability.
- All interface limits were respected for base case scenarios.

Two scenarios were examined for each of the Spring Light Load (SLL), Summer Peak (SUM), and Winter Peak (WIN) cases:

- IR645 off (i.e., SUM_00).
- IR645 generating at full output with NRIS designation (i.e., SUM_00-N).

Table 5: Base Case Dispatch

Case name	NS load	Wind	NS/NB	NS/NL	Cape Breton Export	Onslow Import	Onslow South	Mainland at Hastings	Hastings from
SLL_00-N	840	470	331	-330	245	281	-47	70	220
SLL_00	890	367	333	-330	245	347	17	81	222
SLL_01-N	835	348	0	-165	-45	30	12	-45	96
SLL_01	863	245	0	-165	7	82	65	-13	82
SUM_00-N	1424	593	336	-475	608	666	291	291	328
SUM_00	1451	490	332	-475	708	762	392	346	384
SUM_01-N	1413	433	-98	-330	424	385	421	211	251
SUM_01	1438	330	-95	-330	457	484	517	230	271
SUM_02-N	1433	433	332	-475	802	900	504	419	382
SUM_02	1463	330	330	-475	907	1000	606	476	441
SUM_03-N	1627	403	101	-475	846	927	745	447	419
SUM_03	1635	300	100	-475	845	926	745	447	419
WIN_00-N	2183	593	151	-320	652	763	504	370	259
WIN_00	2183	490	154	-320	651	867	605	374	262
WIN_01-N	2174	213	3	-320	733	875	704	426	331
WIN_01	2183	110	-2	-320	844	981	816	486	394
WIN_02-N	2169	593	336	-320	849	1036	591	474	366
WIN_02	2178	490	331	-320	957	1137	697	533	426
WIN_03-N	2165	213	0	-475	923	1054	887	522	430
WIN_03	2174	110	-4	-475	1016	1141	979	572	483

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

7.2 Load Flow Contingencies:

All load flow contingencies must meet the following post contingency requirements:

- All system elements must be within 110% of their thermally limited ratings (assuming system operator action can resolve the overload in < 10 minutes)
- Steady state bus voltage must remain within 90% - 110% of nominal voltage following correction by automatic tap changers.
- Any Pre/Post contingency voltage change at buses must be < 10% prior to tap changer action

The studied contingencies must include breaker failure, which can impact multiple system elements.

7.3 Load Flow Results:

The results for the load flow analysis identified the contingency loss of L6054 (43V-Canaan Rd to 101V-MacDonald Pond) as a limiting contingency. For cases with summer ratings and maximum wind generation online at 110W, the loss of L6054 creates a thermal overload of L6004 (short term overload rating of 191.4 MVA). As L6004 is operating radially following this contingency, the flow is comprised entirely of the combined generation at 110W and IR645 (102+102.6=204.6 MW). Accounting for losses, the generation capacity at IR645 requires the reduction of two 5.7 MW units (total capacity: 16 x 5.7 = 91.2 MW) to avoid thermal overload post contingency.

As well, it is noted that the operating with L6004 open ended at 90H (open operation of 90H breakers 604 and 605) will cause the same overload on L6054 (101V to 43V).

In summary, the steady state contingencies evaluated in this study demonstrate that IR645 requires Network Upgrades to the transmission line L6004 to operate at its full source capacity of 102.6 MW under NRIS. For ERIS, the IR645 facility can generate up to 91.2 MW prior to curtailment under certain operating conditions.

8.0 Voltage Control

IR645 does not meet NS Power's ±0.95 net power factor requirement at the HV terminals of the ICIF substation and will require supplemental reactive support.

Using the Nordex reactive power capability, shown in Figure 6: *Nordex N149 reactive power capability*, various levels were calculated and are displayed in Table 6: *Power factor analysis results*.

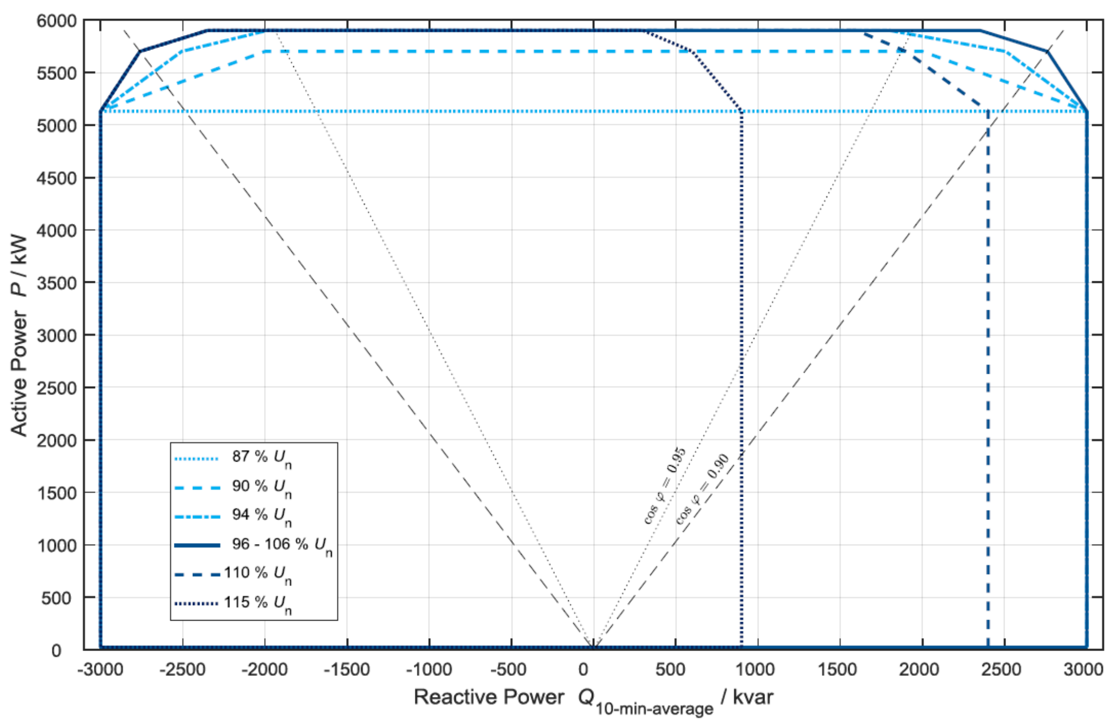

Fig. 2: Q-P-diagram Mode 0.a (5900 kW)

Active power *P* / kW		25	5130	5700	5900
Maximum reactive power range (10-min-average)	87 % U_n -*Q*...+*Q* / kvar	-3000	-3000	-	-
		3000	3000	-	-
	90 % U_n -*Q*...+*Q* / kvar	-3000	-3000	-2000	-
		3000	3000	2000	-
	94 % U_n -*Q*...+*Q* / kvar	-3000	-3000	-2507	-1985
		3000	3000	2507	1800
	96...106 % U_n -*Q*...+*Q* / kvar	-3000	-3000	-2761	-2350
		3000	3000	2761	2350
	110 % U_n -*Q*...+*Q* / kvar	-3000	-3000	-2761	-2350
		2400	2400	1900	1600
	115 % U_n -*Q*...+*Q* / kvar	-3000	-3000	-2761	-2350
		900	900	600	300

Figure 6: Nordex N149 reactive power capability[4]

The Nordex technical bulletin's reactive power capability, shown above in Figure 6, shows the reactive power capability for maximum active power output at various voltage levels. As the IR645 site proposes the use of the 5700 kW variant, the reactive power range at nominal voltage is rated as +/-2761 kvar per unit.

As seen in Table 6 below, IR645 does not meet NS Power's ±0.95 net power factor requirement at nominal voltage when injecting the maximum rated active and reactive power, according to the Nordex reactive capability curve.

Table 6: Power factor analysis results *(@ 1.0 VPU)*

Breakpoints on reactive capability curve (0.96 to 1.06 pu Voltage)	IR645 rated output (18 x 5.7 MW WTG units)				Measurements at HV terminals of the ICIF sub				Meets net 0.95 pf requirement?
	MW	MVAR	MVA	pf	MW	MVAR	MVA	pf	
Max Reactive Injection	102.6	49.7	114.0	0.900	101.0	26.1	104.3	0.968	No
Max Reactive Absorption	102.6	-49.7	114.0	0.900	100.3	-90.2	134.9	0.744	Yes

The net power factor will be re-evaluated when final information on the transformers and collector circuit is provided in the SIS stage.

[4] Reactive power capability - Wind turbine class Nordex Delta4000 - N149/5.X Mode 0.a Document no: 2009087EN Rev. 0, 2020-05-26

A centralized controller will be required, which continuously adjusts the individual generator reactive power output within the plant capability limits and regulates the voltage at the low voltage terminal of the ICIF transformer. The voltage controls must be responsive to voltage deviations, be equipped with a voltage setpoint control, and have facilities that will slowly adjust the setpoint over several *(5-10)* minutes to maintain reactive power within the individual generators' capabilities. Details of the specific control features, control strategy, and settings will be reviewed and addressed in the SIS.

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

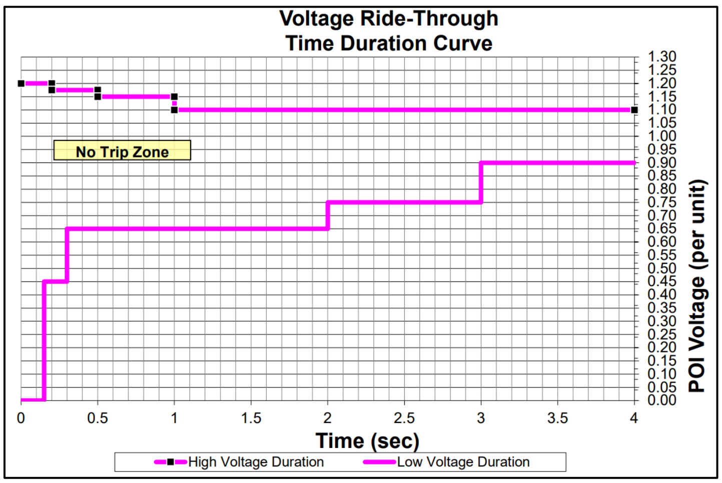

Figure 7: NERC PRC-024-2 Attachment 2

This facility must have voltage ride-through capability as detailed in Figure 7 above and in the NS Power Transmission System Interconnection Requirements *(TSIR)*[5]. The SIS will examine the plant capabilities and controls in detail to specify options, controls, and additional facilities that are required to achieve low voltage ride-through.

9.0 System Security

Transmission System Elements will be required to meet NERC[6] Bulk Electric System (BES) requirements, but not NPCC[7] Bulk Power System (BPS) requirements.

Table 7 summarizes the BPS/BES status of neighbouring system elements:

[5] NS Power Transmission System Interconnection Requirements; https://www.nspower.ca/oasis/standards-codes
[6] North American Electric Reliability Corporation.
[7] Northeastern Power Coordination Council.

Table 7: BPS & BES classification of neighbouring elements

Neighbouring element classification	NPCC BPS	NERC BES
L6004	No	No
L6005	Yes	Yes
L6010	Yes	Yes
L6011	Yes	Yes
L6051	Yes	Yes
L6054	No	No

NPCC BPS criteria is performance based, and currently the 138 kV transmission line L6004 is not designated NPCC BPS. As such, protection systems associated with the new 138kV breaker supplying the radial line to IR645 are not required to comply with NPCC Directory 4 *System Protection Criteria*.

NERC BES criteria uses a bright line approach for expected facilities required for interconnection. As IR645 has dispersed generation totalling more than 75 MVA, Inclusion I4 of the NERC BES Definition would apply, and each generator would be classified as a BES element. As well, the IR645 138 kV bus and 34.5 kV bus, 138–34.5 kV interconnection transformer, and 138 kV tap line would be classified as BES elements.

There is the potential for an exclusion from BES to be granted for the high side (138kV) bus based on further analysis per the NS BES Exception Procedure. This analysis will be initiated as part of the System Impact Study (SIS) and exclusion from BES will only be granted upon subsequent approval by the NS Utility and Review Board (UARB).

10.0 Expected Facilities Required for Interconnection

The following facilities are required to interconnect IR645 to the NSPI system via the 138 kV transmission line L6004 as NRIS.

Network Upgrades for NRIS:

a) Upgrade L6004 thermal rating from 75°C to 100°C between the 90H-Sackville substation and the IR645 POI (~20 km).

b) Install a new transfer trip scheme for any operation of 90H-604 and 90H-605 breakers, manual or automatic, which would open end L6004 at 90H.

c) P&C modifications at 90H-Sackville substation and 101V-MacDonald Pond substation to three-terminal line protection.

The following facilities are required to interconnect IR645 to the NSPI system via the 138 kV transmission line L6004 as ERIS.

Network Upgrades for ERIS:

a) P&C modifications at 90H-Sackville substation and 101V-MacDonald Pond substation to three-terminal line protection.

The following facilities are required to interconnect IR645 to the NSPI system via the 138 kV transmission line L6004 as both NRIS and ERIS.

Transmission Provider's Interconnection Facilities (TPIF):

a) Install a new 138 kV substation complete with a single breaker line tap at the POI at L6004 with control and protection. A Remote Terminal Unit (RTU) to interface with NSPI’s SCADA, with telemetry and controls is required by NSPI.

b) A 138 kV transmission line (~4.4 km) built to NSPI standards from POI on L6004 to the IR645 ICIF substation.

c) Control and communications between the ICIF and the NSPI SCADA and protection system.

Interconnection Customer's Interconnection Facilities (ICIF):

a) Facilities to provide ±0.95 power factor when delivering rated output at the 138 kV bus when voltage is operating between ±5% of nominal. Rated reactive power shall be available through the full range of real power output, from zero to full power.

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 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. NSPI will also have remote manual control of the curtailment scheme.

d) When not at full output, the facility shall offer over-frequency and under-frequency control with a deadband of ±0.2 Hz and a droop characteristic of 4%. The active power controls shall also have the capability to react to continuous control signals from the NSPI SCADA system's Automatic Generation Control (AGC) system to control tie-line fluctuations as required.

e) Real-time telemetry will include MW, MVAR, bus voltages, curtailment state, wind speed, and wind direction.

f) Nominal voltage and frequency operation as specified in the NS Power Transmission System Interconnection Requirements *(TSIR)* Section 7.2.

g) Voltage and frequency ride-through capability as detailed in NS Power Transmission System Interconnection Requirements *(TSIR)* Sections 7.4.1 and 7.4.2.

h) Facilities for NSPI to execute high speed rejection of generation (transfer trip), if determined in the SIS. The plant may be incorporated in SPS runback schemes.

i) The facility must use equipment capable of closing a circuit breaker with minimal transient impact on system voltage and frequency *(matching voltage within ±0.05 PU and a phase angle within ±15 º)*.

j) Operation at ambient temperatures as low as -30ºC.

11.0 NSPI Interconnection Facilities and Network Upgrades Cost Estimate

The present high level, non-binding, cost estimate, excluding HST, for IR645's Network Resource Interconnection Service is shown in the following table. This estimate assumes there is adequate space for new equipment and modifications. This does not include any costs yet to be determined by the SIS.

Table 8: NRIS Cost estimate

	Determined Cost Items	Estimate
Transmission Provider Interconnection Facilities (TPIF) Upgrades		
i.	Single breaker line tap substation (138 kV) complete with P&C at POI and connection to L6004	$ 1,700,000
ii	Spur line from POI to IR645 substation (~4.4 km)	$ 2,200,000
iii.	Protection & control relaying equipment + NSPI RTU	$ 160,000
iv.	Teleprotection & SCADA communications	$ 150,000
	Subtotal:	$ 4,210,000
Network Upgrades (NRIS)		
v.	Upgrade L6004 thermal rating between 90H-Sackville and POI	$ 3,000,000
vi.	Transfer trip scheme for operation of 90H-604/605 breakers	$ 100,000
vii.	P&C modifications at 90H-Sackville and 101V-MacDonald Pond	$ 500,000
	Subtotal:	$ 3,600,000
Totals		
viii.	Network Upgrades + TPIF Upgrades	$ 7,810,000
ix.	Contingency (10%)	$ 780,000
x.	Total of Determined Cost Items	$ 8,590,000
To Be Determined Cost Items		
xi.	System additions to address potential stability limits	TBD (SIS)

The estimated time to construct the NRIS Network Upgrades and Transmission Provider's Interconnection Facilities is 24-36 months after receipt of funds and cleared ROW access is provided.

The present high level, non-binding, cost estimate, excluding HST, for IR645's Energy Resource Interconnection Service is shown in the following table:

Table 9: ERIS Cost estimate

Determined Cost Items		Estimate
Transmission Provider Interconnection Facilities (TPIF) Upgrades		
i.	Single breaker line tap substation (138 kV) complete with P&C at POI and connection to L6004	$ 1,700,000
ii.	Spur line from POI to IR645 substation (~4.4 km)	$ 2,200,000
iii.	Protection & control relaying equipment + NSPI RTU	$ 160,000
iv.	Teleprotection & SCADA communications	$ 150,000
	Subtotal:	$ 4,210,000
Network Upgrades (ERIS)		
v.	P&C modifications at 90H-Sackville and 101V-MacDonald Pond	$ 500,000
	Subtotal:	$ 500,000
Totals		
vi.	Network Upgrades + TPIF Upgrades	$ 4,710,000
vii.	Contingency (10%)	$ 470,000
viii.	Total of Determined Cost Items	$ 5,180,000
To Be Determined Cost Items		
ix.	System additions to address potential stability limits	TBD (SIS)

The estimated time to construct the ERIS Network Upgrades and Transmission Provider's Interconnection Facilities is 18-24 months after receipt of funds and cleared ROW access is provided.

Under ERIS operation, the IR645 facility will be curtailed under any operating condition where a single contingency would otherwise lead to a violation of thermal loading limits on L6004 or L6054. This can be expected to occur approximately 45 hours annually, based on historical generation data.

Note that the proposed transmission corridor requires more detailed design work that is not in scope for this FEAS. Below are a few highlighted issues that could significantly impact the estimate for this project:

- Easements and/or structure relocations for the new transmission line to the ICIF and the ICIF substation.
- Easements and/or structure relocations for the new TPIF substation at the POI.

12.0 Loss Factor

Loss factor is calculated by running the winter peak load flow case with and without the new facility in service, while keeping 91H-Tufts Cove as the NS Area Interchange bus. This methodology reflects the load centre in and around 91H-Tufts Cove. This calculation does not include losses associated with the IR645 ICIF or TPIF. A negative loss factor reflects a reduction in system losses.

With IR645 in service at full output, the loss factor is calculated as 1.0%.

Table 10: Loss factor

Parameter	Generation (MW)
IR645 (net at POI)	100.9
System Losses w IR645	90.1
System Losses w/o IR645	89.1
Delta	1.0
2023 loss factor	1.0%

13.0 Preliminary Scope of Subsequent SIS

The SIS will be conducted in accordance with the GIP with the assumption that all appropriate higher-queued projects will proceed, and the facilities associated with those projects are installed. It will provide a more comprehensive assessment, based on NSPI, NPCC, and NERC criteria, of the technical issues and requirements to interconnect the proposed facility as requested.

The assessment will consider, but not be limited, to the following:

- Contingency analysis for both steady state and system stability.
- Ride-through and operation following a contingency (n-1 operation).
- The minimum transmission and substation additions/upgrades that are necessary to permit operation of this generating facility, under all dispatch conditions, catering to, at a minimum, the first contingencies listed below.
- Options and ancillary equipment that the customer must install to control flicker, voltage and ensure that the required ride-through capability.
- Identify guidelines and restrictions applicable following a first contingency (curtailments, etc.).
- Loss Factor.
- Determination of BPS designation.
- Changes to SPS schemes required for operation of this generating facility
- Under-frequency load shedding.
- Facilities that the customer must install to meet the requirements of the GIP.

Parameters for a generic model must be supplied for transient analysis in PSS/e.

The SIS will determine the facilities required to operate this facility at full capacity, withstand the contingencies as defined by NPCC/NERC and identify any restrictions that must be placed on the system following a first contingency loss. The SIS will be conducted with the assumption that all projects higher queued will proceed and the facilities associated with those projects are installed.

Any changes to SPS schemes required for operation of this generating facility, in addition to existing generation and facilities that can proceed before this project, will be determined by the SIS as well as any required additional transmission facilities. The determination will be based on NERC[8] and NPCC[9] criteria as well as NSPI guidelines and good utility practice. The SIS will also determine the contingencies for which this facility must be curtailed.

A thorough assessment will be provided to ensure that the facilities will meet applicable NSPI, NPCC and NERC transmission design criteria.

Additionally, electromagnetic transient (EMT) study may be required to account for IR645 control system to coordinate with other facilities in the transmission system and to ensure fault ride through.

Nova Scotia Power
Transmission System Operations
2022-03-31

[8] NPCC Directory #1: *Design and Operation of the Bulk Power System*
[9] NERC Reliability Standard TPL-001-4: *Transmission Operations*