6911 Southpoint Drive (B03)
Burnaby, BC
V3N 4X8

September 4, 2025

[redacted]

Dear [redacted]

RE: [redacted] Wind Project - Interconnection System Impact Study Report

Enclosed is the Interconnection System Impact Study report for the proposed [redacted] Wind project submitted under Attachment M-1: Standard Generator Interconnection Procedures (SGIP) including Standard Generator Interconnection Agreement (SGIA) of the Open Access Transmission Tariff (OATT).

This letter provides a non-binding good faith estimate of the cost and time to construct the facilities required to interconnect your project to BC Hydro's Transmission System, being the Network Upgrades, based on the findings of the Interconnection System Impact Study.

Open Access Transmission Tariff

The OATT defines Network Upgrades as additions, modifications, and upgrades to BC Hydro's Transmission System required at or beyond the Point of Interconnection (POI) to accommodate the interconnection of the Generating Facility to the BC Hydro's Transmission System. Pursuant to the OATT, BC Hydro will design, procure, construct, install, and own the Network Upgrades. While BC Hydro will pay the costs for the Network Upgrades, the Interconnection Customer provides security for such costs.

Cost Estimate

Based on the Interconnection System Impact Study, the non-binding good faith estimated cost (typical accuracy range of +100%/-35%) for Network Upgrades required to interconnect your project is **$111.5M**. Please note that the cost estimate may be amended in the near future to reflect the SIS results of other Interconnection Requests (with the same queue position) in the same region.

Major Scope of Work Identified:

Stations Scope – [redacted] Terminal Switching Station [redacted]

- Acquire adequate property close to the existing transmission line 2L055 and construct a new 138kV switching station.

Transmission Line Scope

- Re-terminate line 1L055 near the POI to the new switching station and install up to three 138kV 3-pole dead-end structures for each side of the re-termination.
- A dead-end structure should be installed as a demarcation point between Customer owned 138kV line and BC hydro owned portion of the line.
- Thermal upgrade with a new parallel overhead 138kV transmission line of ~10.5 km.

- Install fibre optical cable

Protection and Control Scope at [redacted] Substation (HLD), Savona Substation (SVA), Nicola Substation (NIC), , Fraser Valley Office (FVO), South Interior Office (SIO), the new [redacted] Switching Station, including:

- Modifications/additions to the local Load Shedding Remedial Action Scheme (RAS) include updating protection relays, adding alarms, metering, and telemetry at HLD, and installing the complete control system suite at [redacted]

Telecom Scope at Carson Microwave Station (CRN), Edmonds Office (EDM) ,HLD, FVO, SIO, [redacted] and other microwave stations, repeater stations, and substations, including:

- Installing/adding routing nodes and equipment, towers, antennas, battery and charger requirements, microwave radio systems, routers and firewalls, and teleprotection terminals.
- Installing new [redacted] Substation Passive Reflector [redacted], and [redacted] Passive Repeater ([redacted]

Exclusions:

- GST
- Outage costs
- Permits
- Cost change due to currently fluctuations
- Book value of decommissioned equipment
- Cost of acquiring additional right-of-way for ingress, egress and thermal upgrade of 1L055
- As the exact location of the newly proposed [redacted] switching station is unknown, site-specific requirements including but not limited to dewatering, ground improvements, slope stabilization, etc. are not included.

Key Assumptions:

- Construction may be completed by BCH or its contractor(s)
- 15 months of construction
- For thermal upgrade of 1L055, constructing a parallel new section
- Environmental assessment certificate not required for this project.
- Telecom estimates are included in this estimate as a lump sum and it is assumed that some costs will be shared with other Interconnection Requests of the same queue position.

Key Risks:

- Delays in receiving documentation or funding from the Interconnections Customer which may delay key milestones
- No defined supply chain strategy, construction costs may increase depending on delivery method
- Costs may be affected by market conditions and escalation
- Telecom scopes present high risk of change due to rapidly evolving technologies and standards.

Technical Interconnection Requirements and Revenue Metering Requirements

As part of our commitment to maintaining a reliable and responsive grid, BC Hydro maintains its Technical Interconnection Requirements (TIR) documentation (updated in February 2024). You will be required to meet the TIR as your project will be connecting to the BC Hydro Transmission system. Some of the revisions made in February 2024 include new provisions for Inverter-Based Resources (IBRs), which are required to participate in primary frequency regulation. BC Hydro looks forward to working closely with you so that you can meet the TIR and can assist with any technical questions you may have. For more details on the TIR, please refer to:

https://app.bchydro.com/content/dam/BCHydro/customer-portal/documents/transmission/tgi/60kV-500kV-TIR-for-power-generators-2024-feb.pdf

The Revenue Metering requirements to interconnect your project have been identified in the System Impact Study report. However, the Revenue Metering costs are not included in the above estimate as they are separate from the cost of Network Upgrades. Revenue Metering costs that are attributable to the Interconnection Customer are to be paid in cash. For more details on Revenue Metering requirements and responsibilities, please refer to:

https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/distribution/standards/ds-rmr-complex-revenue-metering.pdf.

Schedule

Based on the Interconnection System Impact Study, the non-binding good faith estimated in-service date for your project's Network Upgrades is **June 30, 2028** to align with the requested in-service date from your Interconnection Request. To achieve this timeline, we may need to expedite certain activities, including engineering design and procurement of equipment; the expediting of activities may result in increased costs.

Timely actions required from you for the rest of the interconnection process to minimize risks to the schedule:

- Submission of any additional required technical data
- Submission of any required information or documents such as demonstration of Site Control
- Execution of a Standard Generator Interconnection Agreement
- Providing Financial commitments and securities, as required

Please note that changes to your interconnection request, delays in data submission or financial commitments may also impact the target in-service date.

Next Steps

In Fall 2025, we are targeting to issue a final invoice for the System Impact Study costs. This invoice will reflect the total amount due or amount to be refunded, taking into account the System Impact Study deposits already paid.

Should you wish to discuss the contents of the SIS, BC Hydro can arrange for an optional SIS Review Meeting. Following the SIS Review meeting, BC Hydro will provide you with a cost estimate for the Facilities Study, which is being conducted concurrently with the SIS Study, along with any additional data requirements.

As the Facilities Study deposit has already been received, we kindly ask that you confirm your intention to continue with the Facility Study with the scope of work identified in the System Impact Study report following your review of the report. In the case we require more information from you, we will require the additional information to be provided in a timely fashion.

If you have any questions, please contact Transmission Generator Interconnections team at transmission.generators@bchydro.com.

Sincerely,

[redacted]

Interconnections Manager, Transmission Generator Interconnections

BC Hydro

Encl.: [redacted] [redacted]_System Impact Study_Report.pdf

[redacted]

BC Hydro
Power smart

[redacted] Project

Interconnection System Impact Study

BC Hydro EGBC Permit to Practice No: [redacted]

[redacted]

Prepared for: [redacted]

Prepared by: [redacted]

Sr. Engineer, Interconnection Planning

Reviewed by: [redacted]

Manager, Interconnection Planning

Accepted by: [redacted]

Manager, Transmission Planning

Report Metadata

Header:	[redacted] Project
Subheader:	Interconnection System Impact Study
Title:	[Company Fax]
Subtitle:	BCH Interconnection Queue # [redacted]
Report Number:	625C-APR-00001
Revision:	0
Confidentiality:	Public
Date:	2025 Sep 04
Volume:	1 of 1
Prepared for:	[redacted] Inc.
Prepared by:	[redacted]
Title:	Sr. Engineer, Interconnection Planning
Checked by:	[redacted]
Title:	Specialist Engineer, Interconnection Planning
Reviewed by:	[redacted]
Title:	Manager, Interconnection Planning
Related Facilities:	Facility station code – [redacted] Line designation – 1L55
Additional Metadata:	Transmission Planning 2025-027 Filling subcode 1350

Revisions

Revision	Date	Description
0	2025 Sep	Initial release

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Acronyms

The following are acronyms used in this report.

BCH British Columbia Hydro and Power Authority

[redacted] [redacted] Project

COD Commercial Operation Date

CT Current Transformer

DTT Direct Transfer Trip

EMS Energy management System

ERIS Energy Resource Interconnection Service

FRT Fault Ride-Through

FVO Fraser Valley Office

G/S Generation Shedding

HAM Hamilton Microwave Repeater

HLD Highland Substation

HS Heavy Summer

[redacted] [redacted] Substation

[redacted] [redacted] Terminal Statior

[redacted] [redacted] Project

HW Heavy Winter

IC Interconnection Customer

ILM Interior to Lower Mainland

IP Internet Protocol

IPO Independent Pole Operated

ISD In-Service Date

[redacted] [redacted] Project

KLY Kelly Lake Substation

LLD Lower Level Dam Substation

LS Light Summer

MC Measurement Canada or Canada federal regulations

MSV Mount Savona Microwave Repeater Station

NERC North American Electric Reliability Corporation

NIC Nicola Substation

NRIS Network Resource Interconnection Service

OOS Out of Service

PODR Point of Delivery Reference

POI Point of Interconnection

POM Point of Metering

PPIS Power Parameter Information System

PV Photovoltaic

PY/SY Primary/standby

[redacted] [redacted]Station

RAS Remedial Action Scheme

SCC System Control Centre

SIS System Impact Study

STL Spatsum Substation

STM Stump Pumping Station

SVA Savona Substation

TIR BC Hydro 60 kV to 500 kV Technical Interconnection requirements for Power Generators

TOV Temporary Overvoltage

TT Transfer Trip

VT Voltage Transformer

WECC Western Electricity Coordinating Council

WKTP West Kelowna Transmission Project

Executive Summary

[redacted] the Interconnection Customer (IC), requests to connect a wind farm, [redacted] Project, to the BC Hydro (BCH) system in the South Interior West region.

The [redacted] Project has [redacted] (WTGs), each with the rated capacity of 7.7 MVA. The total installed capacity of the project is 197.2 MW, with a maximum power injection of 191.7 MW at the proposed Point of Interconnection (POI).

The proposed POI is located on BC Hydro's existing 138 kV transmission line 1L55, approximately 27 km from [redacted] Substation (HLD). The IC's proposed Commercial Operation Date (COD) is December 31, 2028.

To interconnect the [redacted] Project to the BCH Transmission System at the proposed POI, the SIS has concluded the following requirements:

1. A new 138 kV switching station (referred to as "[redacted] on the BCH's existing circuit 1L55 is required at or close to the proposed POI for interconnecting the generating project to the BCH system. With the new switching station [redacted] 1L55 will be segregated into two segments, temporarily referred as: 1L55_A ([redacted] and 1L55_B ([redacted]). The 138 kV transmission line which is to be built by the IC for connecting the project is temporarily designated as 1L55_C ([redacted]. These temporary line designations will be replaced by permanent ones at a later stage of interconnection study.

2. The connection of [redacted] Project will cause 1L55 line thermal overload on the section from HVC tap to [redacted] under system normal (N-0) condition. It is required to thermally uprate the overhead circuit 1L55 (HVC Tap to [redacted] approximately 10.5 km in length) to achieve a continuous rating of 851 Amps or higher at 30°C ambient temperature.

3. Certain contingencies may result in additional thermal overloads and other performance concerns in the system, which are attributed to the addition of [redacted] project. To address those concerns, the [redacted] Project is required to participate in generation runback remedial action schemes (RAS). No transient instability or transient voltage violation was observed in the area under the applicable study contingencies.

4. The proposed [redacted] project is capable of meeting the dynamic reactive power capability requirement specified in the BC Hydro's TIR Section 6.4.2 over most of the MW operating range (including full to lower MW output), and also provide partial reactive capability at zero MW output provided that the turbine's "STATCOM" option is enabled. This "STATCOM" mode shall be made available at each of the wind turbines of the wind farm.

5. Virtual Inertia Control (VIC), a form of Fast Frequency Response (FFR), is required at the [redacted] Project. The proposed wind turbine generators, when equipped with the VIC option, will temporarily boost the MW output to limit the system frequency drop after a major frequency event. The VIC settings should be determined in coordination with BC Hydro in the later stage of interconnection studies.

6. Anti-islanding protection is required for the [redacted] project and shall be configured in the manner that does not compromise the required ride-through performance.

7. A telecommunication-based anti-islanding Direct Transfer Trip (DTT) scheme in accordance with IEEE Std 2800-2022 is required. This will be implemented by tripping the entrance circuit breaker of the [redacted] wind farm or opening the designated circuit breakers at [redacted] switching station for any protection tripping or manual opening of line 1L55_A between HLD and [redacted] [redacted]

8. Voltage sags caused by energization of entrance transformers are expected to exceed the limits specified by the TIR. The [redacted] Project is required to mitigate the transformer inrush current using point-on-wave (POW) controller with independent pole operated (IPO) circuit breakers.

9. BC Hydro will provide line protections for 1L55_A, 1L55_B and 1L55_C (BC Hydro end only). As part of the line protection replacements for each of the three lines, telecommunication facilities will be required to accommodate the new protection schemes. The IC shall provide required relays, telecom facility and associated equipment at its facilities to accommodate the new protection schemes.

10. The WTGs of the [redacted] project are required to have fault ride-through (FRT) capability per BCH's TIR. Using the default settings provided by the IC, the fault ride-through performance of the WTGs is satisfactory and does not result in unexpected tripping or momentary cessation in dynamic simulations. BC Hydro will follow up on the ride-through settings during the pre-commissioning stage.

Note that the above conclusions are made based on the IC's input data and study assumptions listed in Section 4, which represents the best available information for the study.

A non-binding good faith cost estimate and the estimated schedule of the Network Upgrades identified for the project interconnection are provided in a letter that accompanies this report. The identified Network Upgrades refer to the additions and modifications to the BC Hydro owned transmission facilities for interconnecting the proposed project.

1 Introduction

[redacted] the Interconnection Customer (IC), requests to connect its [redacted] Project to the BC Hydro (BCH) system in the South Interior West (SIW) region.

The project has [redacted] (WTGs), each with capacity of 7.7 MVA. Each turbine will have a maximum active power output of 6.8 MW. The total installed capacity of the project is 197.2 MW, with a maximum power injection of 191.7 MW at the proposed Point of Interconnection (POI).

The proposed POI is located on BC Hydro's existing 138 kV transmission line 1L55, approximately 27 km from [redacted] Substation ([redacted] The IC's wind farm step-up substation, designated as [redacted] will connect to the proposed POI through a 138 kV, 4.6 km transmission line to be built by the IC. The IC's proposed Commercial Operation Date (COD) is December 31, 2028. The project reviewed in this SIS is summarized in Table 1-1 below.

Table 1-1: Summary of Project Information

Project Name	[redacted] Project	
Interconnection Customer	[redacted]	
Point of Interconnection	A point on 1L55, 27 km from HLD	
IC Proposed COD	December 31, 2028	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	191.7 MW (Summer)	191.7 MW (Winter)
Number of Wind Turbines	[redacted]	
Plant Fuel	Wind	

At the wind farm, the power generated from the WTGs is initially stepped up to 34.5 kV through WTG step-up transformers. The voltage is then further increased to 138 kV through [redacted] main power transformers. The power is delivered to the proposed POI via the customer built 138 kV line. The existing line 1L55 is a radial circuit originating from BC Hydro's [redacted] Substation [redacted] serving several industrial loads and connecting an existing solar farm owned by a different customer.

Figure 1-1 illustrates the Nicola-Highland-Savana region transmission system. Nicola Substation (NIC) is a major hub in this region with a strong tie to 500 kV network, which includes:

- Two 500/230 kV transformers (NIC T2 & T3),
- Two existing 230/138 kV transformers (NIC T5 & T6), and
- A future 230/138 kV transformer (NIC T7) to be added.

Additionally, Savona Substation (SVA) is a BC Hydro owned 230/138 kV substation, which connects to 500 kV Kelly Lake Substation (KLY) via two 230 kV transmission lines, 2L92 and 2L93.

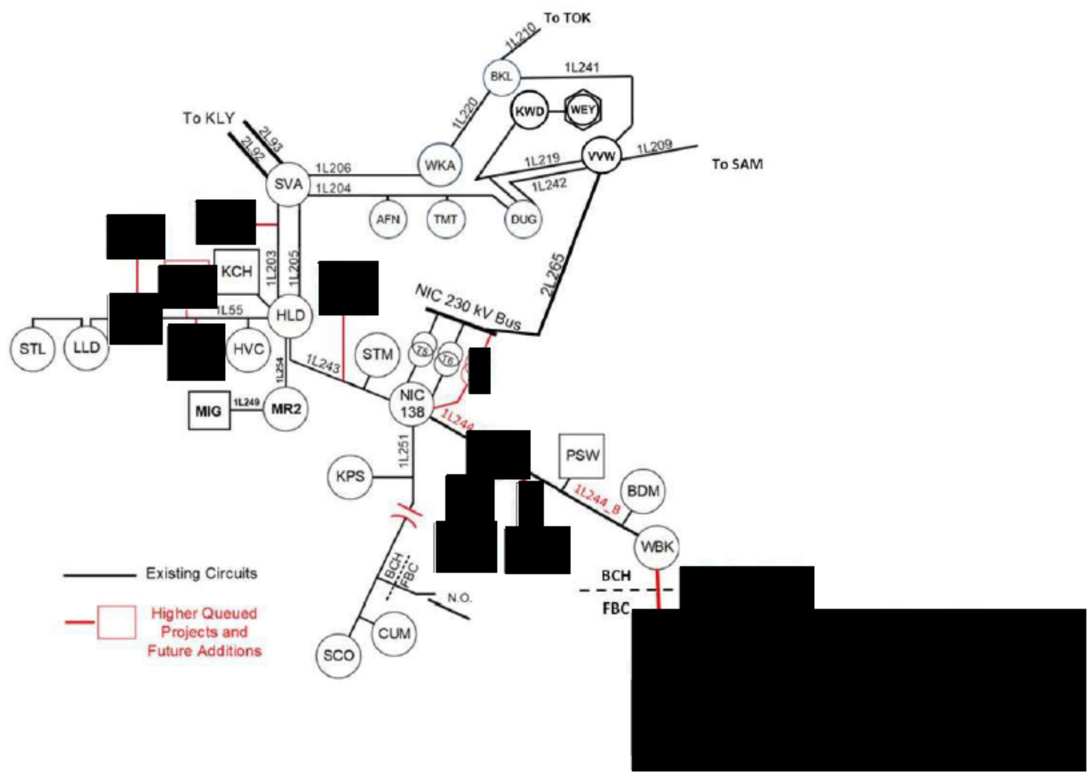

Figure 1-1: Nicola-Highland-Savana Region Transmission System with Addition of [redacted] Project

The HLD substation is connected to SVA Substation via 1L203 and 1L205, and to NIC substation via 1L243.

The HLD Substation serves several industrial facilities and interconnects multiple generating stations owned by third parties, including the proposed [redacted] and newly commissioned 15 MW QYS Solar farm.

In addition, HLD also interconnects two existing power plants owned by independent power producers (IPP) in the region:

- Kwoiek Creek Generating Station (KCH) with a total capacity of 60 MW is connected to HLD via a 72.7 km, 138 kV transmission line 1L57.
- Merritt Green Energy Project Generating Station (MIG) with a total capacity of 40 MW is connected to Merritt 2 Substation (MR2) which is fed by 1L254 from HLD.

To support regional load growth, BC Hydro has planned to build several network reinforcement projects, including upgrades at Nicola substation, reconductoring of 1L243, and series compensation on 1L251. Further details can be found in Section 4.

For the 2024 power call SIS, there are four additional projects in the same SIW area, which are listed below.

- [redacted] Project [redacted] Proposed COD: 9/30/2030
- [redacted] Project [redacted] Proposed COD: 12/31/2028
- [redacted] Project [redacted] Proposed COD: 10/1/2031
- [redacted] Project [redacted] Proposed COD: 9/30/2028

The four projects above have been considered in the [redacted] SIS. The cumulative impact of those projects would contribute to the transmission constraints in the SIW area.

Appendix A shows the plant schematic diagram of the [redacted] Project.

2 Purpose of Study

The purpose of this System Impact Study (SIS) is to assess the impact to the BC Hydro transmission system of interconnecting the proposed Customer's facility, in accordance with the relevant BCH Open Access Transmission Tariff (OATT).

This study aims to identify transmission constraints and determine system reinforcement options, including the implementation of a Remedial Action Scheme (RAS) for generation shedding or generation runback, to ensure adequate performance and the reliable operation of the BC Hydro transmission system.

The SIS is performed in accordance with the North American Electric Reliability Corporation (NERC) reliability standards, Western Electricity Coordinating Council (WECC) performance criterion, and BC Hydro transmission planning requirements, specifically:

- NERC standards: FAC-002-3, TPL-001-4;
- WECC Performance Criterion: TPL-001-WECC-CRT-4;
- BC Hydro's 60 kV to 500 kV Technical Interconnection Requirements for Power Generators per NERC Standard FAC-001-3; and
- BC Hydro's Transmission Asset Planning FAC-002-3 Study Guide.

3 Scopes of Study

This study investigates potential thermal overloading, voltage performance and stability constraints of the transmission system as a result of the proposed interconnection and identifies the requirements of the Network Upgrades in the BC Hydro transmission system to accommodate the IC's proposed interconnection.

This study is based on available information provided by the IC. Further studies or a study update may be required when additional data from the IC is available or key study assumptions are updated.

This study does not address the possible impact of the proposed interconnection on the adjacent systems that are neighboring with the BCH system. BC Hydro coordinates and cooperates with the neighboring systems per FAC-002-3 for them to assess the potential impact on the adjacent systems when needed.

4 Assumptions and Conditions

This SIS is performed based on the information in the IC's interconnection data form submitted on March 7, 2025.

The study assumptions and conditions used in the study cases include the forecasted load levels, generation resource plans, and facility ratings, etc. for the selected study years as appropriate. The key assumptions and study conditions used in this SIS are listed below:

- The 2032 Heavy Winter (HW) and 2033 Heavy/Light Summer (HS/LS) study cases are selected to study the proposed interconnection of the subject generating project.

- The generation dispatch in the study model represents both existing and future generators in BC Hydro's Base Resource Plan (BRP) that was available to start the SIS. Specifically, the 2024 power call projects in the study area ([redacted] [redacted] [redacted], [redacted]) and a recently commissioned solar generating station (QYS) are included in the study model.

- Similarly, the forecasted loads in the study model represent the existing and future loads that were available at the time of preparing the SIS.

- The facility ratings used in this study are based on BC Hydro operating order 5T-10 dated May 12, 2025, and 5T-14 dated Dec 18, 2024.

- West Kelowna Transmission Project (WKTP) Alterative 3e[1] which will build a new 138 kV line from BC Hydro's West Bank substation (WBK) to Fortis BC's Recreation substation (REC) is included in the study model after F2032.

- Nicola Substation Transformation Capacity Reinforcement will add a new 230/138 kV transformer at NIC (i.e. NIC T7) to mitigate the possible transformer overload associated with the industrial load increase in the Highland region.

- 1L243 Line Reconductoring project will accommodate an industrial load increase in the Highland region.

[1] BC Hydro, West Kelowna Transmission Project, see details in https://www.bchydro.com/energy-in-bc/projects/wktp.html

5 System Studies and Results

Based upon the IC's submitted information and the area system conditions, a new switching station (referred to as [redacted]) at the proposed POI on 1L55 is required to interconnect the IC's generating project to the BCH system. The addition of the new switching station would help to maintain reliability and adequate protection performance to serve the existing customers and the new [redacted] project.

With the new switching station HVTX, the existing line 1L55 will be segregated into two segments, temporarily referred to as: 1L55_A ([redacted]) and 1L55_B ([redacted]). The customer-built 138 kV line for [redacted] project is referred to as 1L55_C ([redacted]). These temporary line designations will be replaced by permanent ones at a later stage of interconnection study.

5.1 Steady-State Power Flow Study

A series of pre- and post-contingency power flow analyses were performed to assess the impact of the subject project on the regional transmission system. The study was performed using the selected 2032 Heavy Winter (HW) load and 2033 Heavy/Light Summer (HS/LS) load conditions, based on the assumptions and considerations outlined in Section 4.

Table 5-1 shows a summary of stead-state performance concerns and the identified solutions associated with the interconnection of the subject project.

The Base Scenario reflects the high generation outputs from the Columbia River generating system while the Additional Scenario reflects the high generation outputs from the Peace River system. The two generation dispatch scenarios could result in different power flow distributions on 1L203 and 1L205.

For all the studied load conditions (33LS, 33HS, 32HW), 1L55 line thermal overloading for the section from the HVC tap to the proposed switching station ([redacted] was observed in system normal (P0) and single contingency (P1) conditions. This section of 1L55 line is approximately 10.5 kilometers, and the existing seasonal ratings for this section are 254 A Summer (30°C) and 488 A Winter (0°C). The line 1L55 from HVC tap to [redacted] shall be thermally uprated to a minimum of 851 Amps at 30°C ambient temperature.

Thermal overloads on the circuits 1L203, 1L205, 1L204 and 1L206 were observed under various contingencies. These overloads are attributed to the addition of [redacted] project together with other neighbouring power call projects. The detailed study results are listed in Appendix B.

To address those post-contingency overloads, the [redacted] project is required to participate in generator runback remedial action schemes (RAS), as detailed in Table 5-2 on Page 12. In addition to those listed in Table 5-1, 500 kV system contingencies may result in a mild overload on some of the 138 kV circuits, which can be addressed by the local RAS described in Table 5-2.

Table 5-1: Steady-State Performance Concerns and Proposed Solutions

Performance Concern	Conditions Observed	Contingencies that Result in the Facility Overload	Proposed Solution
1L55 Overload (HVC tap to [redacted]	LS, HS, HW	P0: System normal	Thermally uprate the overhead circuit 1L55 (HVC Tap to [redacted] 10.5 km in length) to achieve a continuous rating of 851 Amps or higher at 30°C ambient temperature.
1L203 Overload	LS, HS, HW	P1.2: 1L205 P2.1: Opening 1L243 at NIC, Open HVC entrance breaker P2.3: HLD 1CB2, HLD 1CB3, SVA 1CB2, and SVA 1CB4	Generation Runback RAS at [redacted] (See Section 5.6 for Details)
1L205 Overload	LS, HS, HW	P1.2: 1L203 P2.1: Opening 1L203 at SVA, Opening 1L243 at NIC, Open HVC entrance breaker P2.3: HLD_1CB5, SVA_1CB5, SVA_1CB6	Generation Runback RAS at [redacted] (See Section 5.6 for Details)
1L204 Overload	HS, HW with a higher flow on 5L87 southbound (KLY to NIC)	P1.2: 1L206, 1L220, 2L265 P1.3: VVW_T2 or T3 P2.1: Opening 1L243 at NIC P2.3: SVA_1CB10, SVA_1CB8	Generation Runback RAS at [redacted] (See Section 5.6 for Details)
1L206 Overload	HS with a higher flow on 5L87 southbound (KLY to NIC)	P2.1: Opening 1L204 at SVA	Generation Runback RAS at [redacted] (See Section 5.6 for Details)

Note: P1.2, P2.1 and P2.3, etc. are the contingency categories defined in NERC TPL-001-4.

The proposed [redacted] project is capable of meeting the dynamic reactive power capability requirement specified in the BC Hydro's TIR Section 6.4.2 over most of the MW operating range (including full to lower MW output), and also provide partial reactive capability at zero MW output provided that the turbine's "STATCOM" option is enabled. This "STATCOM" mode shall be made available at each of the wind turbines in the [redacted] project.

5.2 Transient Stability Study

Transient stability studies have been performed using the 2032 heavy winter and 2033 light summer base cases to assess the impact of a maximum power injection of 191.7 MW from the [redacted]Project and other call projects on the transmission network in the vicinity area, in accordance with the TPL-001-WECC-CRT- 4 Performance Criteria.

Appendix C shows a summary of the transient stability study results for 2033 light summer condition with the addition of [redacted]Project. No transient instability or transient voltage violation was observed under the study conditions and contingencies.

In addition, upon the IC's submission, the WTG at [redacted] project can provide fast frequency response (FFR) when the Virtual Inertia Control (VIC) is enabled. The VIC function is required at [redacted]project to limit the system frequency drop during a major frequency event. The VIC settings should be determined in coordination with BC Hydro in the later stage of interconnection studies.

5.3 Reliability Impact to Adjacent Utilities

The study did not find any reliability impact of the proposed interconnection to adjacent systems. Therefore, it is not necessary to coordinate the study results with adjacent utilities in accordance with FAC-002-3.

5.4 Analytical Studies

Analytical studies identified the following key findings and recommendations:

- The risk of temporary overvoltages (TOVs) was assessed under the unintentional islanding contingency. Islanding occurs when the [redacted]and possibly a portion of the area loads become isolated from the main grid but remain energized. Based on the analysis, no risk of TOVs was identified.
- Anti-islanding protection is required for the [redacted]Project. A telecommunication-based Direct Transfer Trip (DTT) scheme in accordance with IEEE Std 2800-2022 is required. This will be implemented by tripping the entrance circuit breaker of the [redacted]or opening the designated circuit breakers at [redacted]switching station for any protection tripping or manual opening of line 1L55_A between HLD and [redacted]

- The 138 kV circuit breakers within the new switching station, [redacted] designated for isolating the [redacted] Project, are required to have out-of-phase interrupting capability. The rated out-of-phase current should be no less than 5 kA and should not exceed 25% of the rated short-circuit breaking current.
- Voltage disturbance resulting from energization of [redacted] 138kV main power transformers was studied under system normal and contingency conditions. The calculated voltage sags exceeded the limit specified in the TIR. [redacted] Project is required to mitigate the transformer inrush current using point-on-wave (POW) controller with independent pole operated (IPO) circuit breakers.
- The harmonic current injection from the [redacted] shall not exceed the limit specified in the TIR, which follow IEEE Std 519-2022. Harmonic studies will be conducted at a later stage when the spectrum of IPP's harmonic current injection becomes available.
- Electromagnetic Transient (EMT) model is parameterized with the voltage and frequency ride-through settings, and the model parameters meet TIR requirements. BC Hydro will follow up on this topic during the pre-commissioning stage.
- The electromagnetic transient responses of the [redacted] turbine generators including the active power control, reactive power control, and dynamic active power support under abnormal frequency conditions, is consistent with the facility's electrical and control design specifications.
- The converter-driven stability of the [redacted] was evaluated under reduced short circuit ratios (SCRs). Simulations were conducted to analyze the dynamic interactions between the control systems of the power electronic-based equipment and the transmission system. The [redacted] demonstrated stable operation under these reduced SCR conditions, with SCR values determined based on credible operating scenarios selected for the study.

5.5 Short Circuit Analysis

The short circuit analysis for the System Impact Study is based upon the latest BC Hydro system model, which includes project equipment and impedances provided by the IC. Thevenin impedances for the near-term system conditions and the ultimate fault levels at POI are not included in this report but will be made available to the IC upon request.

5.6 Remedial Action Schemes

In addition to the thermal overload concerns listed in Table 5-1, thermal overload issue on various sections of 1L243 was observed for the following P6 multiple contingencies:

- 1L203 SVA-[redacted]POI OOS and 1L205 contingency
- 1L205 OOS and 1L203 open end at SVA

A RAS based on the local detections is proposed in Table 5-2 to mitigate the overload issues identified.

Table 5-2: Proposed RAS for Regional System Contingencies

No.	Overload protection (Note 1)	Generation Runback at [redacted] (Note 2)	Speed Requirement (Note 3)
1	Install overload protection at SVA on 1L203, which operates if 1L203 is overloaded and the MW flow is flowing into SVA	Yes	5 to 10 seconds
2	Install overload protection at SVA on 1L204, which operates if 1L204 is overloaded and the MW flow is flowing out from SVA	Yes	
3	Install overload protection at SVA on 1L205, which operates if 1L205 is overload and the MW flow is flowing into SVA	Yes	
4	Install overload protection at SVA on 1L206, which operates if 1L206 is overloaded and the MW flow is flowing out from SVA	Yes	
5	Install overload protection at NIC on 1L243, which operates if 1L243 flow is larger than (1L243 MW rating – X MW) and the MW flow is flowing into NIC, where the X is the maximum load at STM.	Yes	
Note 1: Ambient temperature and line load dependent overload protection shall be used. Note 2: The run back signal shall be sent to [redacted]station to reduce the generation to a pre-determined value. This value will be provided in an operational planning study later before the IC connecting to BC Hydro system. Note 3: The speed requirement is defined as the time from the detection of the overload to the runback signal being sent out.			

It is noted that the integration of the [redacted]Project will also implement runback schemes to manage increased generation injection during certain 500 kV contingency events via the Energy Management System (EMS) based RAS.

5.7 Station Upgrade Requirements

To interconnect the [redacted] Project to the BC Hydro transmission system, following are the station work required at the proposed [redacted] Terminal Station [redacted]

- Acquire adequate property for a new [redacted] Station [redacted] close to the existing transmission line 1L55. The property shall be chosen considering ultimate stage of the [redacted] switching station.
- Construct a new outdoor 138kV, 3-circuit breaker ring bus station. Three circuit breakers (1CB1, 1CB2 and 1CB3) and associated disconnects shall be rated at 3000A.
- Install three 138 kV line terminals with associated motorized disconnects, Surge Arresters and Capacitor Voltage Transformers for the transmission lines 1L55_A, 1L55_B and 1L55_C. The three line disconnects and associated bus works shall be rated at 1200 A or higher.
- Install associated station service, P&C, telecom, SCADA, and mechanical equipment including fire detection/extinguishing devices.
- Install other necessary equipment and facilities required for new [redacted] switching station, including 138 kV station service VTs, diesel generator for station service backup, a new control building and other required substation structure, and station ground system.
- Refer to draft one-line sketch (Appendix H) for details. The one-line sketch will be adjusted based on the size and orientation of the acquired property.

To thermally uprate 1L55 as per required in Section 5.1, following are the station work required at Highland substation (HLD):

- Replace 1L55 line jumpers to [redacted] (B phase), and to [redacted] and replace the conductor between [redacted] (B phase) to [redacted] with 1200 A rating conductors. Replace [redacted] with 1200 A disconnect.

5.8 Transmission Line Upgrade Requirements

The transmission line scope of work for BC Hydro is the following.

5.8.1 1L55 Ingress/Egress (In/Out) of HVTX

The following transmission line work is required for 1L55 Ingress/Egress In-and-Out of the proposed switching station [redacted] Refer to Appendix E for Conceptual Ingress/Egress (In/Out) of 1L55 and approximate POI location.

- Re-terminate line 1L55 at approximately Str [redacted] (POI) to the new switching station [redacted] forming section 1L55_A, and re-terminate the other portion of line 1L55 at approximately Str [redacted] to [redacted] forming section 1L55_B. This may require up to three BC Hydro standard 138kV 3-pole dead-end wood pole structures Depending on the location of the [redacted] the exact structure/ circuit number will be determined at a later stage.
- Last Span from IC's line 1L55_C to [redacted] switching station.

In addition, a 3-pole dead-end structure should be installed as a demarcation point between IC owned 138kV line and BC hydro owned portion of the line. BC Hydro will design and build the last span into the [redacted] switching station. If the IC will design and build the last span from the customer line to [redacted] switching station, this design will need to be reviewed by BCH for acceptance.

5.8.2 1L55 Thermal Uprating

To thermally uprate 1L55 line section between HVC Tap and [redacted] (as required in Section 5.1), the following transmission line work is required.

- Section 1 (HVC tap to Str [redacted] approximately 1.5 km) and Section 2 (Str [redacted] to [redacted] approximately 9 km): new conductor such as ACSR Drake or equivalent may be considered.
- BCH has considered the following two alternatives for thermally uprating of Section 2. Alternative 2 is preferred and used for cost estimation. This alternative only requires a brief outage reducing the operations risks and unpredictability from multiple outages.
  - Alternative 1: reconductoring with ACSR Drake conductor and structure replacements may be expected. Numerous outages may be required for alternative 1.
  - Alternative 2: permanent relocation of the existing line 1L55 from Str [redacted] to Str [redacted] (approximate 9 km) by building a brand-new parallel overhead transmission line section. Upon completion, a brief outage on 1L55 will allow this newly built line section to be in service. The existing section from Str [redacted] to Str [redacted] may be removed later. New right-

of-way may be required to accommodate the new parallel permanent relocation section of 1L55.

5.8.3 1L55 Fibre Addition from [redacted] to QYS

Supply and install a 48-strand fibre optic cable from [redacted] to QYS ([redacted] to Str 14-02 to QYS substation, approximately 8.5 km).

5.9 Protection, Control and Telecommunications

5.9.1 Protection

BC Hydro will provide line protections for 1L55_A, 1L55_B and the [redacted] terminal of 1L55_C. Protection work is also required at some BC Hydro substations in the area.

The IC is required to provide the following for the interconnection of its [redacted] project.

- Entrance protection that complies with the current version of the "60 kV to 500 kV BC Hydro Technical Interconnection Requirements for Power Generators."
- Provide [redacted] SEL-411L-1 relays (firmware and options specified by BC Hydro) relays and associated telecom facilities at the entrance of [redacted] to provide protection coverage for 1L55_C. BC Hydro P&C Planning will provide core protection settings for these relays.
- Provide instantaneous protections for transformers, buses, and lines between its 138 kV entrance breakers to unit step-up transformer HV buses.
- Main transformer [redacted] should not operate in parallel at 34.5 kV, the tie breaker of 34.5 kV buses should be normally open.
- The IC is responsible for implementing RAS requirements at their facility with no single point of failure.
- The IC is responsible for NERC PRC-related tasks and settings needed to meet compliance standards within their facilities.
- Provide anti-islanding protection as per Section 5.4.

5.9.2 Control

BC Hydro is to provide a new control system for the new transmission switching station, [redacted] Remote and local control and indication for the new devices that will be installed at [redacted]

BC Hydro control center is to add [redacted] [redacted] and other changes to 1L55 as needed into the Energy Management System (EMS) network model.

The IC will provide SCADA data reporting to the control centers in accordance with the TIR, including required telemetry and status information, which should be available to the EMS at the nearest suitable BC Hydro site with appropriate telecom facilities. This data is supplied to BC Hydro Control Centers in DNP 3.0 format. All data provided in response to poll messages transmitted by BC Hydro must be completed in less than or equal to 2 seconds. Continuous communications using commercial lease or privately constructed connection from the IC to BC Hydro control centers is acceptable provided the performance objective stated in the TIR is met.

The IC's telemetry and status will be routed to the appropriate Data Collection Platform (DCP). BC Hydro control centers are required to reconfigure the existing equipment to accommodate the new IC, include the generators into the network model, and add the new telemetry and alarm points.

The IC is responsible for providing a PPIS meter, the make and model of which is subject to BCH approval, connected to a suitable high voltage source for harmonics and power quality metering.

The IC is responsible for providing a communications link for remote interrogation of the PPIS equipment by BCH servers. Alternative communications include IP cellular modem, IP satellite, BCH WAN (where appropriate) and is subject to BCH review and approval.

Minor work will be required by BC Hydro to recommission telemetry, alarms, and remote access at NIC, HLD and SVA for the new protection relays. Additional work is required at NIC for DFR changes.

5.9.3 Telecommunications

A telecom solution has been identified to meet the telecom requirements for teleprotection, telecontrol, RAS and other network additions (see these requirements in Appendix F). The detailed telecom work scopes and specs will be provided in detail at the later stage of Interconnection Studies.

The IC's Work Required at [redacted]

- Install [redacted] c[redacted] fibre optic cables and terminate them in the control building. Leave 40 m coils of cable on the last structures outside the [redacted] station fence. Install [redacted] node and a [redacted] power system with 8 hours reserve.

BCH's Work Required at [redacted]

- Install antenna with two waveguides, dehydrator and dual shelf frequency-diversity microwave terminals. Install [redacted] nodes. Install [redacted] Ethernet switches. Install Telecom Management Router (TMS) and a [redacted] V DC power system with 8 hours reserve.

The Telecom solution is developed based on the assumption as follows.

a) A passive reflector [redacted] would be employed to bring microwave into HLD from [redacted] Assume that the location of [redacted] at [redacted] 1[redacted] would be suitable for a passive reflector sufficiently elevated above ground level. Geotechnical, field surveys, and path surveys would be necessary for confirmation and property rights would need to be acquired.

b) Four candidate locations are under investigation for the location of [redacted] For this study, assume [redacted] would be located near [redacted] For this study it is assumed that construction of a passive reflector, [redacted] would be necessary to bring microwave into [redacted] from [redacted]

c) Assume HVW is located at: 50° 34' 40" N 121° 2' 50" W.

d) A new switching station [redacted] assumed to contain NERC CIP Low Impact cyber assets, would be employed for the HVW point of interconnection.

e) BCH would perform a microwave link interference analysis through FCSA for the [redacted], HLD-[redacted], HAM-NIC, and NIC-TUK, microwave radio links. Upon success of the interference analysis and upon receipt of required environmental information and other consultation related to new towers and antennas, BCH telecom Engineering would apply for radio licensing through ISED Canada.

f) Assume good cellular data or satellite coverage at [redacted] for the revenue metering and PPIS circuits.

g) New towers at HAM, MSV could be added near an existing tower at each of those sites. And at Tuktakamin Microwave Repeater Station (TUK), it would be possible to use an expansion port on the existing waveguide facing HAM, if required.

h) A recent disruption in the supply chain for passive repeater components would impact the cost and schedule for construction of passive repeater sites at [redacted] and [redacted] It is assumed that a suitable new passive solution could be developed and implemented at those sites.

6 Cost Estimate and Schedule

A non-binding good faith cost estimate and the estimated schedule of the Network Upgrades identified for the project interconnection are provided in a letter that accompanies this report. The identified Network Upgrades refer to the additions and modifications to the BC Hydro owned transmission facilities for interconnecting the proposed project.

7 Revenue Metering

The POM will be installed inside the IC's station as per Section 6.2 of Technical Interconnection Requirements for Power Generators.

The IC will supply current and voltage transformers. The IC will provide BC Hydro the transformers technical specifications and Measurement Canada (MC) Notice of Approval (NOA) Number before ordering to ensure compatibility with the revenue meters.

BCH's and the IC's roles and responsibilities are outlined in Section 10 of the Requirements below. The cost includes BC Hydro supplied metering materials (enclosures, meters, cables, telecoms equipment) and labor (planning, design, construction). The cost does not include other BCH costs such as project management.

Please refer to Appendix G for Technical Reference and Revenue Metering Systems Management Contact Information

8 Conclusions

This System Impact Study has concluded the following requirements:

1. A new 138 kV switching station (referred to as [redacted]) on the BCH's existing circuit 1L55 is required at or close to the proposed POI for interconnecting the generating project to the BCH system. With the new switching station [redacted], 1L55 will be segregated into two segments, temporarily referred as: 1L55_A ([redacted]) and 1L55_B ([redacted]). The 138 kV transmission line which is to be built by the IC for connecting the project is temporarily designated as 1L55_C ([redacted]). These temporary line designations will be replaced by permanent ones at a later stage of interconnection study.

2. The connection of [redacted] Project will cause 1L55 line thermal overload on the section from HVC tap to [redacted] under system normal (N-0) condition. It is required to thermally uprate the overhead circuit 1L55 (HVC Tap to [redacted] approximately 10.5 km in length) to achieve a continuous rating of 851 Amps or higher at 30°C ambient temperature.

3. Certain contingencies may result in additional thermal overloads and other performance concerns in the system, which are attributed to the addition of [redacted] project. To address those concerns, the [redacted] Project is required to participate in generation runback remedial action schemes (RAS). No transient instability or transient voltage violation was observed in the area under the applicable study contingencies.

4. The proposed [redacted] project is capable of meeting the dynamic reactive power capability requirement specified in the BC Hydro's TIR Section 6.4.2 over most of the MW operating range (including full to lower MW output), and also provide partial reactive capability at zero MW output provided that the turbine's "STATCOM" option is enabled. This "STATCOM" mode shall be made available at each of the wind turbines of the wind farm.

5. Virtual Inertia Control (VIC), a form of Fast Frequency Response (FFR), is required at the [redacted] Project. The proposed wind turbine generators, when equipped with the VIC option, will temporarily boost the MW output to limit the system frequency drop after a major frequency

event. The VIC settings should be determined in coordination with BC Hydro in the later stage of interconnection studies.

6. Anti-islanding protection is required for the [redacted] project and shall be configured in the manner that does not compromise the required ride-through performance.

7. A telecommunication-based anti-islanding Direct Transfer Trip (DTT) scheme in accordance with IEEE Std 2800-2022 is required. This will be implemented by tripping the entrance circuit breaker of the [redacted] or opening the designated circuit breakers at [redacted] switching station for any protection tripping or manual opening of line 1L55_A between HLD and [redacted]

8. Voltage sags caused by energization of entrance transformers are expected to exceed the limits specified by the TIR. The [redacted] Project is required to mitigate the transformer inrush current using point-on-wave (POW) controller with independent pole operated (IPO) circuit breakers.

9. BC Hydro will provide line protections for 1L55_A, 1L55_B and 1L55_C (BC Hydro end only). As part of the line protection replacements for each of the three lines, telecommunication facilities will be required to accommodate the new protection schemes. The IC shall provide required relays, telecom facility and associated equipment at its facilities to accommodate the new protection schemes.

10. The WTGs of the [redacted] project are required to have fault ride-through (FRT) capability per BCH's TIR. Using the default settings provided by the IC, the fault ride-through performance of the WTGs is satisfactory and does not result in unexpected tripping or momentary cessation in dynamic simulations. BC Hydro will follow up on the ride-through settings during the pre-commissioning stage.

Appendix A
Schematic Diagram of the IC's Project

The following shows the plant schematic diagram for the IC's project.

[redacted]

Figure A-1: Schematic Diagram of [redacted]

Appendix B
Steady-State Power Flow Study Results

Base Scenario

The base case scenario considered a northbound power flow on the 5L87 line, corresponding to conditions with elevated power output from Columbia generation sources and reduced output from Peace region facilities.

Table B-1 and Table B-2 contain the key results of power flow studies for the base scenario studied in this SIS.

Table B-1: Branch Overload Report in Base Scenario

Case	IC's Plant Output	Contingency		Branch Loading									
				1L55	1L55	1L55	1L55	1L55	1L203	1L205	1L204	1L243	1L243
		Cat.	Description	POI-QYS	QYS-Substation*	Substation*-HVC tap	HVC tap-HLD	QYS-Substation* (Note 2)	SVA-HLD (Note 1a)	SVA-HLD	SVA-DUG	HLD-[redacted] POI	NIC-[redacted] POI (Note 1b)
Winter Rating				116.6 MVA	116.6 MVA	116.6 MVA	260.8 MVA	260.8 MVA **	191.2 MVA	149.6 MVA	143.4 MVA	319.1 MVA	319.1 MVA
32HW	Max	P0	System Normal	**154%**	**166%**	**163%**	35%	75%	79%	69%	61%	2%	43%
	Max	P1.2	1L203	**154%**	**166%**	**163%**	35%	75%	-	**101%**	43%	2%	43%
	Max	P1.2	1L205	**153%**	**165%**	**162%**	35%	75%	**111%**	-	54%	11%	54%
	Max	P2.1	Opening 1L203 at SVA	**154%**	**166%**	**162%**	35%	75%	24%*	**130%**	49%	17%	61%
	Max	P2.1	Opening 1L243 at NIC	**153%**	**165%**	**162%**	35%	75%	**114%**	**112%**	84%	43%	1%
	Max	P2.3	HLD 1CB2	**153%**	**165%**	**162%**	35%	75%	**128%**	-	60%	-	-
	Max	P2.3	SVA 1CB10	**154%**	**166%**	**162%**	35%	75%	71%	60%	**106%**	8%	52%
	Max	P2.3	SVA 1CB2	**153%**	**165%**	**162%**	35%	75%	**109%**	-	56%	12%	55%
	Max	P2.3	SVA 1CB4	**153%**	**165%**	**162%**	35%	75%	**109%**	-	56%	12%	55%
	Max	P2.3	SVA 1CB5	**154%**	**166%**	**163%**	35%	75%	-	**101%**	42%	2%	43%
Summer Rating				60.7 MVA	60.7 MVA	60.7 MVA	203.4 MVA	203.4 MVA **	172.8 MVA	118.6 MVA	143.4 MVA	252.6 MVA	252.6 MVA
33HS	Max	P0	System Normal	**298%**	**321%**	**316%**	46%	97%	86%	86%	62%	4%	59%
	Max	P1.2	1L203	**299%**	**322%**	**316%**	46%	97%	-	**125%**	44%	3%	59%
	Max	P1.2	1L205	**297%**	**321%**	**315%**	46%	97%	**121%**	-	55%	19%	73%
	Max	P2.1	Opening 1L203 at SVA	**298%**	**322%**	**316%**	46%	97%	25%*	**165%**	49%	26%	81%
	Max	P2.1	Opening 1L243 at NIC	**299%**	**323%**	**317%**	46%	97%	**130%**	**146%**	86%	54%	1%

	Max	P2.3	HLD 1CB2	**297%**	**321%**	**315%**	46%	97%	**148%**	-	62%	-	-
	Max	P2.3	HLD 1CB5	**298%**	**322%**	**316%**	46%	97%	-	**107%**	41%	8%	48%
	Max	P2.3	SVA 1CB10	**298%**	**322%**	**316%**	46%	97%	78%	75%	**104%**	14%	69%
	Max	P2.3	SVA 1CB2	**297%**	**321%**	**315%**	46%	97%	**120%**	-	57%	20%	74%
	Max	P2.3	SVA 1CB4	**297%**	**321%**	**315%**	46%	97%	**120%**	-	57%	19%	74%
	Max	P2.3	SVA 1CB5	**299%**	**322%**	**317%**	46%	97%	-	**128%**	42%	4%	58%
	Max	P2.3	SVA 1CB6	**298%**	**322%**	**316%**	46%	97%	-	**114%**	-	8%	63%
Summer Rating				60.7 MVA	60.7 MVA	60.7 MVA	203.4 MVA	203.4 MVA **	172.8 MVA	118.6 MVA	143.4 MVA	252.6 MVA	252.6 MVA
33LS	Max	P0	System Normal	**296%**	**319%**	**313%**	41%	96%	87%	87%	35%	4%	58%
	Max	P1.2	1L203	**296%**	**320%**	**313%**	41%	96%	-	**127%**	19%	4%	57%
	Max	P1.2	1L205	**295%**	**318%**	**312%**	41%	96%	**121%**	-	29%	17%	72%
	Max	P1.2	5L87	**295%**	**319%**	**313%**	41%	96%	97%	**101%**	14%	11%	40%
	Max	P2.1	Opening 1L203 at SVA	**295%**	**319%**	**312%**	41%	96%	60%*	**163%**	23%	25%	80%
	Max	P2.1	Opening 1L243 at NIC	**296%**	**320%**	**313%**	41%	96%	**129%**	**144%**	59%	54%	1%
	Max	P2.2	Open HVC entrance breaker	**296%**	**320%**	**313%**	96%	96%	**105%**	**112%**	45%	24%	79%
	Max	P2.3	HLD 1CB2	**297%**	**320%**	**313%**	41%	96%	**146%**	-	36%	-	-
	Max	P2.3	HLD 1CB3	**296%**	**320%**	**313%**	41%	96%	**103%**	-	25%	5%	56%
	Max	P2.3	HLD 1CB5	**296%**	**319%**	**313%**	41%	96%	-	**109%**	16%	9%	46%
	Max	P2.3	SVA 1CB2	**295%**	**318%**	**312%**	41%	96%	**113%**	-	38%	23%	77%
	Max	P2.3	SVA 1CB4	**295%**	**318%**	**312%**	41%	96%	**114%**	-	37%	23%	77%
	Max	P2.3	SVA 1CB5	**296%**	**319%**	**313%**	41%	96%	-	**118%**	23%	6%	60%
	Max	P2.3	SVA 1CB6	**296%**	**320%**	**313%**	41%	96%	-	**122%**	-	6%	60%

* Substation: this is referring to a new customer owned substation tapped on 1L55.

Note 1

a) The 1L203 line loading is measured on 1L203 section [redacted] POI – HLD).

b) The 1L243 line loading is measured on 1L243 section (STM tap to [redacted] POI).

Note 2:

** This is to demonstrate the performance adequacy after the 1L55 line section upgrade.

Appendix C
Transient Stability Study Results

Table C-1: Transient Stability Study Results

Category	Contingency	3-Ph Fault Location	Fault Clearing Time (Cycles)		[redacted] Project Performance	Other Generators in the study area
			Close End	Far End		
P1.1	1L57	Close to HLD	8	22	Acceptable	Acceptable
P1.1	1L57	Close to KCH	8	22	Acceptable	Acceptable
P1.1	1L254	Close to HLD	8	22	Acceptable	Acceptable
P1.1	1L254	Close to MR2	8	22	Acceptable	Acceptable
P1.2	1L203	Close to SVA	8	9	Acceptable	Acceptable
P1.2	1L203	Close to [redacted]	8	9	Acceptable	Acceptable
P1.2	1L203	Close to HLD	8	9	Acceptable	Acceptable
P1.2	1L205	Close to SVA	8	9	Acceptable	Acceptable
P1.2	1L205	Close to HLD	8	9	Acceptable	Acceptable
P1.2	1L243	Close to HLD	8	9	Acceptable	Acceptable
P1.2	1L243	Close to NIC	8	9	Acceptable	Acceptable
P1.2	1L243	Close to [redacted]	8	9	Acceptable	Acceptable
P1.2	2L92	Close to KLY	6	8	Acceptable	Acceptable
P1.2	2L92	Close to SAV or SVA 12T3	6	8	Acceptable	Acceptable
P1.2	2L93	Close to KLY	6	7	Acceptable	Acceptable
P1.2	2L93	Close to SVA or SVA 12T1	6	7	Acceptable	Acceptable
P1.2	1L55 ([redacted])	Close to [redacted]	24	-	Acceptable	Acceptable
P1.2	[redacted]	[redacted] Entrance CB	24	-	Acceptable	Acceptable
P1.3	NIC T5 + T3	-	6	-	Acceptable	Acceptable

P1.3	NIC T6 + T2	-	6	-	Acceptable	Acceptable
P2-3	SVA 2CB5	-	15	-	Acceptable	Acceptable
P2-3	HLD 1CB2	-	9		Acceptable	Acceptable
P2-2	HVC TN HV BUS	138 kV side	8	-	Acceptable	Acceptable
P2.2	HLD T2 LV bus	25 kV side	60	-	Acceptable	Acceptable

Appendix D
Power Flow and Dynamic Models and Data

Each feeder is represented by an equivalent generator in power flow case with the following data:

- G1: MBASE: 53.9 MVA, P_{max}: 47.6 MW, V_{nom}: 0.9 kV
- G2: MBASE: 53.9 MVA, P_{max}: 47.6 MW, V_{nom}: 0.9 kV
- G3: MBASE: 46.2 MVA, P_{max}: 40.8 MW, V_{nom}: 0.9 kV
- G4: MBASE: 30.8 MVA, P_{max}: 27.2 MW, V_{nom}: 0.9 kV
- G5: MBASE: 38.5 MVA, P_{max}: 34.0 MW, V_{nom}: 0.9 kV

In dynamic simulation, each equivalent generator is represented by a user-defined WTG model [redacted] which is proprietary and parameterized with vendor support. Table D-1 shows a selection of model parameters used in this SIS.

Table D-1: Selected Model Parameters in WTG User-Defined Model “[redacted]

Parameter #	Value	Description
[redacted]	1	[redacted]
[redacted]	1	[redacted]
[redacted]	1	[redacted]

In addition, the wind farm model package includes a user-defined [redacted] controller model [redacted] which is proprietary and parameterized with vendor support. Table D-2 shows a selection of model parameters used in this SIS.

Table D-2: Selected Parameters in user-defined wind park controller model “NXWFC_4184”

Parameter #	Value	Description
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Appendix E

Transmission Line Diagrams

The diagram below shows the POI Location.

Figure E-1: POI (approx. [redacted] km from HLD) on 1L55

The diagram below shows Conceptual Ingress/Egress (In/Out) of 1L55.

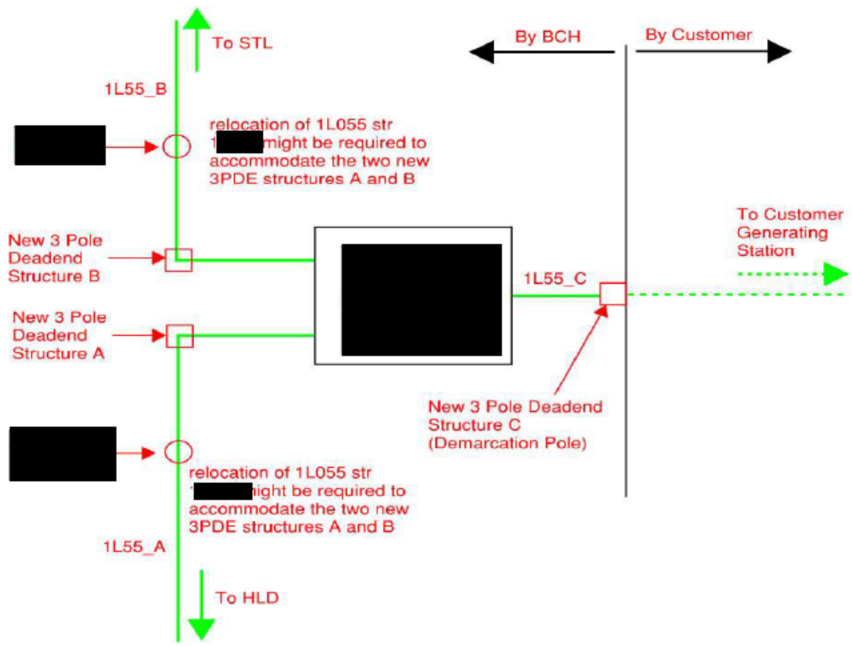

Figure E-2: Conceptual Ingress/Egress (In/Out) of 1L55

Appendix F

Telecom Requirements and Telecom Block Diagram

Below is a summary of Teleprotection, RAS and Telecontrol requirements for Telecom, along with the telecom block diagram that illustrates the telecom solution identified in this SIS.

Teleprotection Requirements for Telecom

- Provide WECC Level 3 64 kbps synchronous circuits between HLD and [redacted]for “[redacted]Digital Teleport” and [redacted] SY Digital Teleport”. Physical interface shall be C37.94 optical over multimode fibre using ST connectors.

- Provide WECC Level 3 64 kbps synchronous circuits between HLD and QYS for “[redacted]Digital Teleport” and “[redacted] SY Digital Teleport”. Physical interface shall be C37.94 optical over multimode fibre using ST connectors.

- Provide WECC Level 3 64 kbps synchronous circuits between [redacted]and QYS for “[redacted]PY Digital Teleport”” and “[redacted] SY Digital Teleport””. Physical interface shall be C37.94 optical over multimode fibre using ST connectors.

- Provide WECC Level 3 64 kbps synchronous circuits between [redacted]and [redacted] for “[redacted]PY Digital Teleport” and ‘[redacted]SY Digital Teleport”. Physical interface shall be C37.94 optical over multimode fibre using ST connectors.

RAS Requirements for Telecom

- Provide WECC Level 1 transfer trip facilities from NIC to [redacted]for “NIC 500KV Contingency PY/SY G/S (Runback) TT to [redacted] and “NIC 500KV Contingency PY/SY G/S (Runback) TT to [redacted]

- Provide WECC Level 1 transfer trip facilities from NIC to [redacted]for “NIC 1L243 PY G/S (Runback) TT to [redacted] and “NIC 1L243 SY G/S (Runback) TT to[redacted]

- Provide WECC Level 1 transfer trip facilities from SVA to [redacted] for "SVA 138KV PY G/S (Runback) TT to[redacted]and "SVA 138KV SY G/S (Runback) TT to [redacted]

Telecontrol Requirements for Telecom

- [redacted] SCADA circuit off FVO & SIO.
- [redacted] SCADA circuit off FVO & SIO.
- [redacted] REMACC circuit off EDM.

Other Requirements for Telecom

- Provide corporate VPRN circuits at HLD, [redacted], and [redacted]
- See assumption f) in Section 5.9.3.

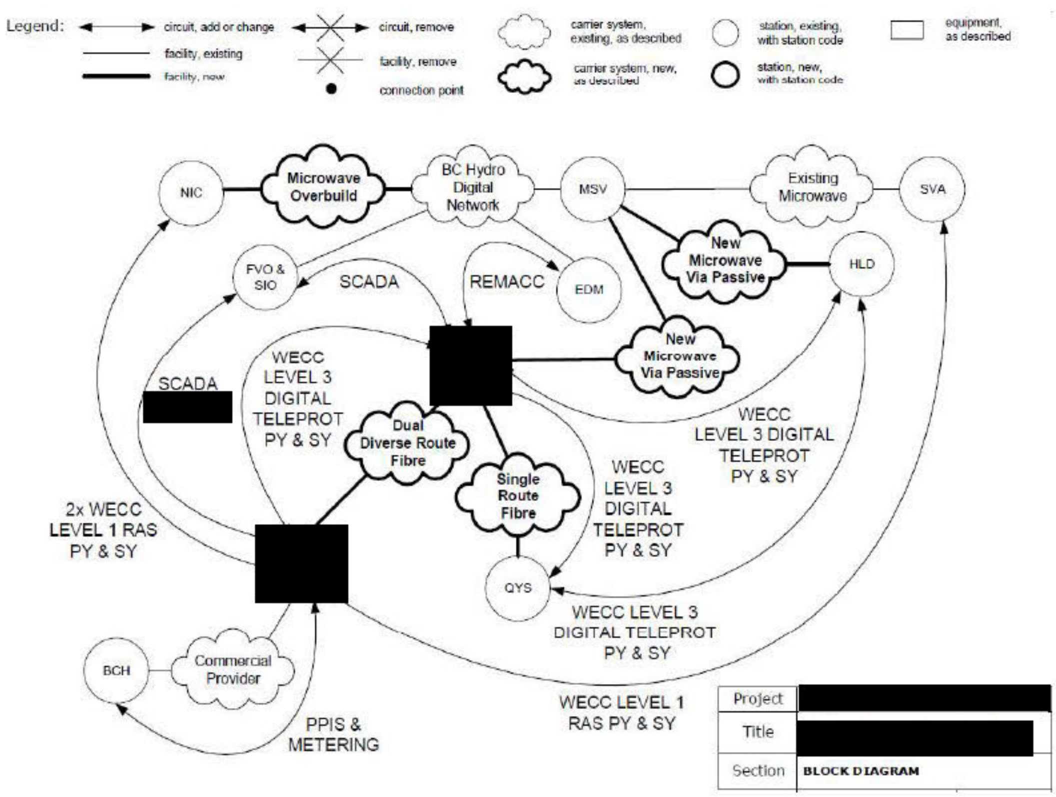

Figure F-1: Telecom Block Diagram Identified in the SIS of [redacted] Project

Appendix G
Revenue Metering Related Telecommunications Requirements

A telecommunications channel is required for remote read/download data from the main and the backup meters. The design, supply and installation of the communications equipment shall be coordinated between BCH Revenue Metering, BCH Telecom, the Power Generator and the Telecommunications Service Provider. The IC should provide a terminal / connector inside the BCH meter cabinet. Where the POI is on a 69 kV voltage class or higher BC Hydro transmission system and where a conventional wire-line telephone is installed, ground potential rise protection shall be provided. Alternative technologies may be used, e.g., cellular, fiber optic, microwave, satellite etc. however these solutions must be discussed and approved by BCH before installation. The bottom line is: - BCH MV-90 Server must be able to access and download data from the meters remotely as they do when they dial in a site using a standard phone line (wireless or landline). For more details, please, refer to Section 8 of BCH Revenue Metering Requirements for Complex Metering published at the Revenue Metering webpage and at the BC Hydro external website.

Technical Reference and Contact
Requirements for Complex Revenue Metering

Revenue Metering Systems Management can be contacted at
metering.revenue@bchydro.com

Appendix H
Station Work Required at the Proposed [redacted] Transmission Switching Station [redacted]

The following diagram is the preliminary one-line sketch for the proposed [redacted] Terminal Station [redacted]

[redacted]

Figure H-1: Proposed [redacted] Terminal Station [redacted]