BC Hydro
Power smart

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

September 10, 2025

[redacted]

[redacted]

Dear [redacted],

<u>RE: [redacted] Project - Interconnection System Impact Study Report</u>

Enclosed is the Interconnection System Impact Study report for the proposed [redacted] 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 **$16.5M**. 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:

Transmission

- Supply & installation of new 230kV structures and disconnect switches to provide tap connection to 2L391.
- New Right-Of-Way to accommodate the tap connection.

Protection and Control

- Line protection relays at BC Hydro's South Bank substation (SBK) and Shell Groundbirch switching station (SGB) associated with 2L391 will be upgraded to convert from a two terminal line protection to a three terminal line protection.
- Recommission telemetry, alarms, and remote access at SBK and SGB for the new protection relays.

Telecommunications

- Implement a new microwave radio link between the new switching station (TYTX) and Fort St. John substation (FJN).
- Perform a tower study at FJN and reinforce or build a new tower as required.
- Build a new tower at TYTX.
- Install a tower and antenna facing the IPP's [redacted] generation station (SKD) and FJN at TYTX.

Exclusions:

- GST
- Outage costs.
- Permits
- Cost change due to Currency Fluctuations.
- Book value of decommissioned equipment.
- Work in the IPP's facilities.
- Station works other than P&C/SCADA & Telecom scope.

Key Assumptions:

- The estimate assumes the following for the new overhead transmission line structures:
  - Each new customized 230kV dead-end structure consists of three (3) 90-ft steel poles, is self-supported, and includes caisson foundations (2.135m Ø x 10.5m deep).
  - Each new non-standard 230kV switch structure consists of two (2) 90-ft steel poles and one (1) 65-ft steel pole, is self-supported and includes caisson foundations.
  - New non-standard 230kV tap structure consists of 3-90ft high steel poles, self-supported and with caisson foundations.
  - The new BCH standard 230kV dead-end structure to be installed as a demarcation point has three (3) wood poles, each with a length of 90ft.
- Outages can be scheduled as required.
- Excavated materials assumed to be non-contaminated and/or non-hazardous.
- Construction may be completed by either BC Hydro or its Contractor(s). It is assumed there is no major difference in construction costs between the two.
- 12 months of construction.
- Local construction crew will be engaged for this project, thus no Living Out Allowances (LOA).
- Estimate assumes that BC Hydro will execute the following scopes: Engineering, Project Management, Construction Management, Procurement and Contract Management.
- The required Right-of-Way for the tap and switch structures is still unknown; however, the estimate assumes a width of 40 meters and a length of 509 meters.

Key Risks:

- Archaeological finds during construction.
- Availability of outage windows.

- Resource availability.
- Delays in receiving documentation or funding from the Interconnections Customer which may delay key milestones.
- Major equipment, materials, and general contractor pricing higher than estimated.
- Major Equipment delivery presents potential project cost and schedule risks, based on variance in equipment lead times.
- Additional right of way or acquisition may be required to accommodate equipment.
- No defined supply chain strategy at this stage.
- Project schedule may be longer than expected, leading to increased costs.
- Telecom scope presents high risk of change due to rapidly evolving technologies and standards. Additionally, the telecom scope for this project relies on work performed for the new switching station (TYTX) completed under another interconnection project.
- Cost of materials and major equipment may be affected by market conditions and escalation.

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 **Quarter 2, 2030** 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 report, BC Hydro can arrange for an optional SIS Review Meeting. After the SIS Review meeting, BC Hydro will provide you with a cost estimate for the Facilities Study and any additional data requirements. After being provided with the cost estimate, we ask that you provide written confirmation to proceed with the Facilities Study.

In addition to the confirmation, you will be required to provide additional data for the Facilities Study.

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]**_System Impact Study_Report.pdf**

CC: [redacted]

BC Hydro
Power smart

[redacted] Project

Interconnection System Impact Study

BC Hydro EGBC Permit to Practice No: 1002449

Powertech Labs Inc. EGBC Permit to Practice No: 1002531

[redacted]

Prepared for: [redacted]

Prepared by: [redacted]
Senior Engineer, Powertech Labs Inc.

Reviewed by: [redacted]
Principal Engineer, Powertech Labs Inc.

Accepted by: [redacted]
Manager, Transmission Planning

BC Hydro
Power smart

Report Metadata

Header:	[redacted] Project
Subheader:	Interconnection System Impact Study
Title:	[redacted] Project
Subtitle:	[redacted]
Report Number:	1016H-APR-00001
Revision:	0
Confidentiality:	Public
Date:	2025 Sep 08
Volume:	1 of 1
Prepared for:	[redacted]
Prepared by:	[redacted]
Title:	Senior Engineer, Powertech Labs Inc.
Checked by:	[redacted]
Title:	Specialist Engineer, Powertech Labs Inc.
Reviewed by:	[redacted]
Title:	Principal Engineer, Powertech Labs Inc.
Related Facilities:	Facility station code – SKD Line designation – 2L391
Additional Metadata:	Transmission Planning 2025-025 Filling subcode 1350

Revisions

Revision	Date	Description
0	2025 Sep	Initial release

Disclaimer of Warranty, Limitation of Liability

This report was prepared solely for internal purposes. All parties other than BC Hydro are third parties.

BC Hydro does not represent, guarantee or warrant to any third party, either expressly or by implication:

any information, product or process disclosed, described or recommended in this report.

BC Hydro does not accept any liability of any kind arising in any way out of the use by a third party of any information, product or process disclosed, described or recommended in this report, nor does BC Hydro accept any liability arising out of reliance by a third party upon any information, statements or recommendations contained in this report. Should third parties use or rely on any information, product or process disclosed, described or recommended in this report, they do so entirely at their own risk.

This report was prepared by the British Columbia Hydro And Power Authority ("BCH") or, as the case may be, on behalf of BCH by persons or entities including, without limitation, persons or entities who are or were employees, agents, consultants, contractors, subcontractors, professional advisers or representatives of, or to, BCH (individually and collectively, "BCH Personnel").

This report is to be read in the context of the methodology, procedures and techniques used, BCH's or BCH's Personnel's assumptions, and the circumstances and constraints under which BCH's mandate to prepare this report was performed. This report is written solely for the purpose expressly stated in this report, and for the sole and exclusive benefit of the person or entity who directly engaged BCH to prepare this report. Accordingly, this report is suitable only for such purpose, and is subject to any changes arising after the date of this report. This report is meant to be read as a whole, and accordingly no section or part of it should be read or relied upon out of context.

Unless otherwise expressly agreed by BCH:

(a) any assumption, data or information (whether embodied in tangible or electronic form) supplied by, or gathered from, any source (including, without limitation, any consultant, contractor or subcontractor, testing laboratory and equipment suppliers, etc.) upon which BCH's opinion or conclusion as set out in this report is based (individually and collectively, "Information") has not been verified by BCH or BCH's Personnel; BCH makes no representation as to its accuracy or completeness and disclaims all liability with respect to the Information;

(b) except as expressly set out in this report, all terms, conditions, warranties, representations and statements (whether express, implied, written, oral, collateral, statutory or otherwise) are excluded to the maximum extent permitted by law and, to the extent they cannot be excluded, BCH disclaims all liability in relation to them to the maximum extent permitted by law;

(c) BCH does not represent or warrant the accuracy, completeness, merchantability, fitness for purpose or usefulness of this report, or any information contained in this report, for use or consideration by any person or entity. In addition, BCH does not accept any liability arising out of reliance by a person or entity on this report, or any information contained in this report, or for any errors or omissions in this report. Any use, reliance or publication by any person or entity of this report or any part of it is at their own risk; and

(d) In no event will BCH or BCH's Personnel be liable to any recipient of this report for any damage, loss, cost, expense, injury or other liability that arises out of or in connection with this report including, without limitation, any indirect, special, incidental, punitive or consequential loss, liability or damage of any kind.

Copyright Notice

Contributors

The following Professionals of Record (POR) accept responsibility for their technical content in the specified respective sections. Professionals apply their signature and/or seal for the technical or non-technical content as appropriate.

Section: Discipline:

The entire report except those listed below — Interconnection Planning

Contributed by: [redacted]

Senior Engineer, Powertech Labs Inc.

[redacted]

Section: Discipline:

5.7 — Stations Planning

Contributed by: [redacted]

Specialist Engineer, Substations Growth and Sustainment

[redacted]

Section: Discipline:

5.8 — Transmission Line Engineering

Contributed by: [redacted]

Senior Engineer, Transmission Line Engineering

[redacted]

BC Hydro
Power smart

Section: Discipline:
5.9.1&5.9.2 P&C Planning

Contributed by: [redacted]

Specialist Engineer, Transmission P&C Engineering

[redacted]

Section: Discipline:
5.6 Transmission Operations Services

Contributed by: [redacted]

Specialist Engineer, Transmission Operations Services

[redacted]

Section: Discipline:
5.4

Contributed by: [redacted]

Engineering Team Lead, Substations Growth and Sustainment

[redacted]

Section: 5.9.3

Discipline: Telecom Planning

Contributed by: [redacted]

Specialist Engineer, Telecom Planning & Asset Management

[redacted]

Section: 7

Discipline: Revenue Metering

Contributed by: [redacted]

Senior Engineer, Revenue Metering

[redacted]

BC Hydro
Power smart

Table of Contents

Tables

BC Hydro
Power smart

Figures

Appendices

Acronyms

The following are acronyms used in this report.

BCH	British Columbia Hydro and Power Authority
BMT	Bear Mountain Terminal substation
COD	Commercial Operation Date
CT	Current Transformer
DTT	Direct Transfer Trip
EMS	Energy Management System
ERIS	Energy Resource Interconnection Service
FJN	Fort St John Substation
FRT	Fault Ride-Through
FVO	Fraser Valley Office
GMS	Gordon M. Shrum Generating Station
HS	Heavy Summer Load Conditions
HW	Heavy Winter Load Conditions
IC	Interconnection Customer
IP	Internet Protocol
LS	Light Summer Load Conditions
MC	Measurement Canada or Canada Federal Regulations
MPO	Maximum Power Outputs
NERC	North American Electric Reliability Corporation
NRIS	Network Resource Interconnection Service
PODR	Point of Delivery Reference
POI	Point of Interconnection
POM	Point of Metering
PPIS	Power Parameter Information System
RAS	Remedial Action Scheme

ROW	Right Of Way
SCADA	Supervisory Control and Data Acquisition
SBK	South Bank Substation
SGB	Shell Groundbirch Gas Processing Plant Switching Station
SIS	System Impact Study
SKD	[redacted] 230 kV substation
SLS	Sundance Lakes Substation
SRN	[redacted] Substation
TAW	[redacted] Wind Project
TIR	BC Hydro 60 kV to 500 kV Technical Interconnection requirements for Power Generators
TOV	Temporary Overvoltage
TYTX	[redacted] 230 kV Switching Station
VT	Voltage Transformer
VIC	Virtual Inertia Control
WECC	Western Electricity Coordinating Council
WTG	Wind Turbine Generator

Executive Summary

[redacted] the Interconnection Customer (IC), requests to connect a wind farm referred as [redacted] Project into the BCH system in the Peace Region.

The [redacted] Project will comprise [redacted] The total installed capacity of the project is 199.9 MW, with a maximum power injection of 194 MW at the proposed Point of Interconnection (POI).

The proposed POI is located on BC Hydro's existing 230 kV transmission line 2L391, approximately 28 km from South Bank (SBK) substation in the Peace Region. The IC's proposed commercial operation date (COD) is October 01, 2030.

To interconnect the [redacted] Project at the proposed POI, the System Impact Study (SIS) was conducted and has identified the following requirements and conclusions:

1. A T-tap connection on the BCH's existing circuit 2L391 is acceptable for interconnecting the IC's generating project to the BCH system.

2. The proposed [redacted] Project can meet the 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) (including full to lower MW output), and also provide a partial reactive capability at zero MW output provided that the turbine's "STATCOM" option is enabled. This "STATCOM" mode shall be made available to each of the wind turbines at the [redacted] project.

3. Virtual Inertia Control (VIC), a form of Fast Frequency Response, is required at the [redacted] Project. The proposed wind turbine generators, when equipped with the VIC option, are expected to temporarily boost the MW output 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.

4. BCH will upgrade the line protection relays at BC Hydro's SBK and SGB substations associated with 2L391 to convert from a two terminal line protection to a three terminal line protection for successful integration of [redacted] Project. As part of the line protection upgrade,

telecommunication facilities will be required for each of the three substations. The IC shall provide required relays, telecom facility and associated equipment at its facilities to accommodate the upgraded protection schemes.

5. 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.

6. A telecommunication-based anti-islanding protection scheme is required in accordance with IEEE Std 2800-2022. This will be implemented by tripping the [redacted] Project under any protection tripping of the line 2L391.

7. The [redacted] Project is required to participate in the GMS Area Generation Shedding Remedial Action Scheme (RAS) for contingencies on the Peace region 500 kV transmission system.

8. The interconnection of the [redacted] Project together with the other 2024 Call for Power project in the Peace Region does not cause any system performance violation (i.e. thermal overload, voltage violation, or voltage instability, etc.) under the normal and contingency system operating conditions. No transient instability or transient voltage violation was observed in the area under the applicable study contingencies.

9. Voltage sags caused by energization of entrance transformers are not expected to exceed the limits specified in the TIR. Therefore, no additional mitigation measures are required for transformer energization.

Note that the above requirements and 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 system. The project will have [redacted] The total installed capacity of the project is 199.9 MW, with a maximum power injection of 194 MW at the proposed Point of Interconnection (POI).

The proposed POI is located on BC Hydro's existing 230 kV transmission line 2L391, approximately 28 km from South Bank (SBK) substation. The IC's proposed commercial operation date (COD) is October 01, 2030. The project overview is provided in Table 1-1 below.

Table 1-1: Summary of Project Information

Project Name	[redacted] Project	
Interconnection Customer	[redacted]	
Point of Interconnection	on 2L391 at 28 km from SBK	
IC Proposed COD	October 01, 2030	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	194 (Summer)	194 (Winter)
Number of Generator Units	[redacted]	
Plant Fuel	Wind	

There are seven (7) collecting feeders in the plant, and each turbine generator is connected to one of the seven feeders through its step-up transformer with voltage being stepped up to 34.5 kV from 750 V. These 34.5 kV feeders are further connected to the BCH's 230 kV transmission system via two main power transformers and an IC-owned 0.1 km, 230 kV interconnection line. The IC's 230 kV main substation is referred to as "SKD" in this report.

Figure 1-1 illustrates the interconnection of [redacted] Project to the Peace Region transmission system where SBK is a major 500/230 kV substation which connects the Site C and Peace Canyon two generating stations. SGB is another major substation in the Southern Peace Region 230 kV transmission system, which are connected to Sundance Lakes Substation (SLS), Bear Mountain

Terminal substation (BMT), South Bank Substation (SBK), and [redacted] Substation (SRN).

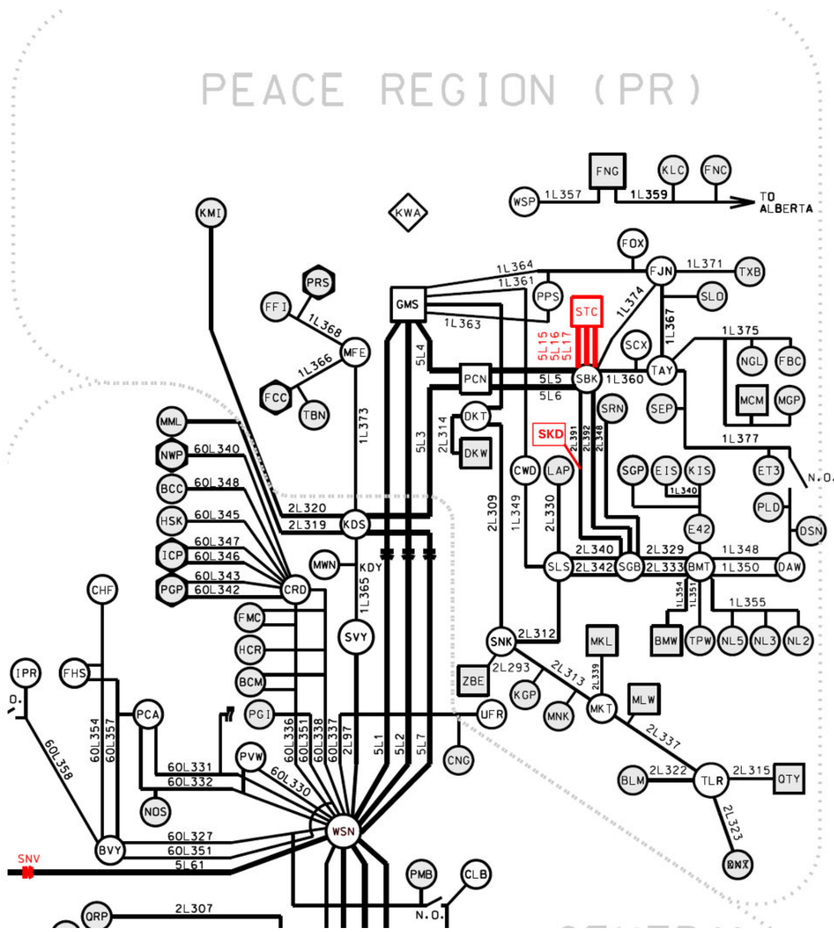

Figure 1-1: Peace Region Transmission System with [redacted] Project Addition

The other 2024 Power Call project named [redacted] Project (TAW) connected to the adjacent 230 kV transmission line 2L292 is also included and modelled in detail in this SIS.

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

2 Purpose of Study

The purpose of the 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 (hereafter referred to as the "TIR") per NERC Standard FAC-001-3
- 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 08, 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 2031 Heavy Winter (HW) and 2032 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 other 2024 power call project in the study area ([redacted]) is 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.
- The regional generations are dispatched to the patterns that stress the transmission system in the study area. In these patterns, the regional generations are typically set to their Maximum Power Outputs (MPO) unless otherwise specified.

5 System Studies and Results

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 2031HW, 2032HS, and 2032LS load conditions, based on the assumptions and considerations outlined in Section 4. Under all load conditions generation in Peace Region is dispatched to high output with Columbia generation dispatched at lower output. Appendix B contains the key results of power flow studies for the base scenario studied in this SIS.

The study has indicated that there is no overload or voltage violation in the studied regional system under system normal operating conditions and under the studied contingencies due to the connection of [redacted] Project.

Note that BCH TIR Section 6.4.2 requires Inverter Base Resource (IBR) power plant to have the dynamic reactive power capability at a minimum of +/- 33% of its MPO from the farms at the high-voltage side of the switchyard over the full MW operating range. The results of the simulations for the [redacted] Project indicate that the project meets this requirement over most of the MW operating range (including full to lower MW output). No additional reactive resource is required at the facility. However, the turbine's "STATCOM" option is required so that each turbine can provide partial reactive power capability at zero MW output.

5.2 Transient Stability Study

Transient stability studies were performed using the 2031HW, 2032HS, and 2032LS base cases to assess the impact from the [redacted] Project interconnection and other successful ones 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 2031HW, 2032HS and 2032LS conditions with the addition of [redacted] Project. No transient instability or transient voltage recovery violation has been observed under the study conditions and contingencies.

In addition, upon the IC's submission, the WTGs at [redacted] Project can provide fast frequency response (FFR) when the turbine's Virtual Inertia Control (VIC) function 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 were performed for the project, which has 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] farm and possibly a portion of 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. This will be implemented by tripping the [redacted] Plant upon any protection tripping of the 2L391 line between SBK and SGB substations.
- Voltage disturbance resulting from energization of a 230/34.5/13.8 kV main power transformer was studied. Under system normal conditions, the voltage sags are not expected to exceed the limits specified in BC Hydro's TIR. No additional mitigation measures are required for transformer energization.
- The harmonic current injection from the [redacted] Project shall not exceed the limits specified in TIR, which follow IEEE Std 519-2022. Harmonic studies will be conducted at a later stage when the detailed spectrum of harmonic current injection becomes available.
- The electromagnetic transient response of the [redacted] Project, 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 wind generating plant 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] farm 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 can be provided upon IC's request.

5.6 Remedial Action Schemes

To maintain and meet the system reliability performance requirements under various operating conditions, the [redacted] Project is required to participate in the GMS Area Generation Shedding RAS for Peace region 500 kV transmission system contingencies.

5.7 Station Upgrade Requirements

No station work is required for this interconnection project.

5.8 Transmission Line Upgrade Requirements

The transmission line scope of work for BC Hydro is to design, build and own the tap connection (See Appendix E for details) that consists of the following:

1. A new BCH non-standard 230kV steel pole tap structure between str 28-05 and 29-02 of 2L391 (replacing str. 29-01).
2. The existing two structures Str 28-05 and 29-02 will need to be replaced with dead-end structures, which may require customized steel poles.
3. Up to three new non-standard 230kV disconnect switch structures. The exact type, number and location of the switches will be decided in a later stage.
4. A new BCH standard 230kV 3 wood-pole dead-end structure will be installed as a demarcation point between BC hydro and the customer.
5. Relocation of 2L391 Str 28-05 and/or 29-02 may be required to accommodate the tap and switch structures.
6. New right of way may be required to accommodate the tap connection.
7. Additional right of way may be necessary between str 28-05 & 29-02 as line deflection is likely required for the non-standard disconnect structures.
8. Multiple outages on 2L391 may be required to accommodate the tap and switch structures construction.

5.9 Protection, Control and Telecommunications

5.9.1 Protection

The [redacted] Project will be required to participate in the GMS Area Generation Shedding RAS Scheme. The line protection relays at BC Hydro's SBK and SGB substations associated with 2L391 will be upgraded to convert from a two terminal line protection to a three terminal line protection. 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 is required to provide the following for the interconnection of its [redacted] Project.

- Entrance protection that complies with the latest version of the BCH TIR.
- Provide two SEL-411L-1 relays (firmware and options specified by BC Hydro) at the entrance of SKD to provide protection coverage for 2L391. BC Hydro P&C Planning will provide core protection settings for these relays.
- 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, settings to compliance standards within their facilities.
- The IC is responsible for providing a communications link for remote interrogation of the Power Parameter Information System (PPIS) equipment by BCH servers.
- Provide anti-islanding protection to prevent [redacted] Project from operating in islanded condition.

5.9.2 Control

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 Energy Management System (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 generator into the network model, and add the new telemetry and alarm points.

The IC is responsible for providing an appropriate Power Parameter Information System (PPIS) meter per the TIR requirements, 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 SBK and SGB for the new protection relays. Additional work is required at SBK for Digital Fault Recorder (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 scope and specs will be provided in detail at a later stage of Interconnection Studies.

Telecom System Upgrade/Extension

- Implement a TYTX-FJN microwave radio link. Perform a tower study at FJN. Reinforce or build a new tower, if required. Build a new tower at TYTX.
- Implement a microwave radio facing SKD at TYTX.

IC's Work Required at SKD

- Install a tower, antenna, and microwave radio facing TYTX, a 48V DC power supply with 8-hour reserve, redundant MPLS equipment connected to the microwave radio, and integrate the teleprotection circuits and the SCADA circuit into the MPLS system.

BCH's Work Required at TYTX

- Install a tower and antenna facing FJN and SKD. BC Hydro telecom designer to confirm antenna heights, azimuths, and sizes . Install two 11

GHZ (if possible, otherwise 7 GHz), dual shelf, microwave radio systems, one facing FJN and one facing SKD, and other telecom equipment. Implement various telecom circuits.

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

a) The new switching station (TYTX) associated with the other 2024 Call for Power project, [redacted], will be completed to a point that it can be used for this project.
b) TYTX is assumed located at 56° 1’ 19.00” N, 120° 58’ 33.44” W.
c) SKD is assumed located at 55° 57’ 44” N, 120° 58’ 50” W.
d) The microwave radio communications between TYTX-FJN and between SKD-TYTX are possible.
e) the Revenue Metering / PPIS circuit(s) required at SKD will be the responsibility of the IC and be carried by a commercial telecommunications provider using cellular wireless, Ku-band satellite, or some other service facility.

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 remote read load profile revenue metering installation should be in accordance with Canada federal regulations (MC) and BC Hydro Requirements for Complex Revenue Metering. The latest version of this document is published at BC Hydro's external website. The revenue metering responsibilities and charges shall be in accordance with Section 10 (10.1 and 10.2). For details about the specific responsibilities, see table on pages.23-25.
- Primary Metering is required; 3-element metering scheme with 3 CTs and 3 VTs connected L-N (Grd) should be used.
- Main and backup load profile interval meters are required to measure the power delivered. The meters will be programmed for 5 minutes interval and will be remotely read each day by BCH Billing Group using MV-90 System; the POM shall have a dedicated communications link (BC Hydro's approved wireless IP solutions, landline or other approved alternative). The communications link should be used for revenue metering only. If there is IP digital cell phone coverage for data in the site, BCH can supply an IP Wireless Communications Modem equipment. BCH Transmission P&C Telecom/P&C Engineering Department should inform the connectivity options for complex metering at this specific site.
- The revenue class meters (main and backup) are Measurement Canada (MC) approved and will be supplied and maintained by BC Hydro.
- When the impedance and losses between the POM and the PODR are significant, the meters should be programmed to account for the line and/or transformer losses between the POM and PODR (usually at the POI). In this case, the customer or the consultant shall provide a letter with the line parameters (and/or power transformer) data signed and stamped by a professional engineer.
- Before definition phase, BCH Revenue Metering department should be contacted to discuss the specifics of the project. A complex metering designer responsible for the metering tasks will be assigned at this point.
- During the feasibility/definition phase, the applicant is to send drawings to the assigned project manager, for distribution to the BCH Revenue

Metering Department showing the 1-line diagram (SLD) and informing the planned metering scheme, meter cabinet location, as well as any other metering related document for review and approval.

In order to finalize the metering option, the IC will work with BCH to determine the required Revenue Metering configuration in accordance with the Electricity Purchase Agreement and associated agreements. Specific metering information is provided in the table below.

Point-of-Metering	230 kV (voltage level), at customer substation
Voltage and current Transformers	The CTs and VTs used on the metering scheme will be supplied by the Power Generator and should be of a model/type approved by Measurement Canada. The CTs and VTs must be pre-approved by BC Hydro's Revenue Metering Department.

8 Conclusions

This System Impact Study has concluded the following requirements:

1. A T-tap connection on the BCH's existing circuit 2L391 is acceptable for interconnecting the IC's generating project to the BCH system.

2. The proposed [redacted] Project can meet the 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) (including full to lower MW output), and also provide a partial reactive capability at zero MW output provided that the turbine's "STATCOM" option is enabled. This "STATCOM" mode shall be made available to each of the wind turbines at the [redacted] project.

3. Virtual Inertia Control (VIC), a form of Fast Frequency Response, is required at the [redacted] Project. The proposed wind turbine generators, when equipped with the VIC option, are expected to temporarily boost the MW output 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.

4. BCH will upgrade the line protection relays at BC Hydro's SBK and SGB substations associated with 2L391 to convert from a two terminal line protection to a three terminal line protection for successful integration of [redacted] Project. As part of the line protection upgrade, telecommunication facilities will be required for each of the three substations. The IC shall provide required relays, telecom facility and associated equipment at its facilities to accommodate the upgraded protection schemes.

5. 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.

6. A telecommunication-based anti-islanding protection scheme is required in accordance with IEEE Std 2800-2022. This will be implemented by tripping the [redacted] Project under any protection tripping of the line 2L391.

7. The [redacted] Project is required to participate in the GMS Area Generation Shedding Remedial Action Scheme (RAS) for contingencies on the Peace region 500 kV transmission system.

8. The interconnection of the [redacted] Project together with the other 2024 Call for Power project in the Peace Region does not cause any system performance violation (i.e. thermal overload, voltage violation, or voltage instability, etc.) under the normal and contingency system operating conditions. No transient instability or transient voltage violation was observed in the area under the applicable study contingencies.

9. Voltage sags caused by energization of entrance transformers are not expected to exceed the limits specified in the TIR. Therefore, no additional mitigation measures are required for transformer energization.

Appendix A
Schematic Diagram of the IC's Project

The following shows the plant schematic diagram for the IC's project (as submitted).

[redacted]

Figure A-1: Schematic Diagram of [redacted] Project.

Appendix B
Steady-state Power Flow Study Results

Table B-1 and Table B-2 show the key results of power flow studies for the base scenarios.

Table B-1: Summary of Branch Loading in Base Study Scenarios

Case	IC's Plant Output	Contingency [1]		Branch Loading (%)					
		Cat.	Description	2L392_A [2]	2L392_B [3]	2L391-A [4]	2L391-B [5]	2L312	2L308
31HW	Winter Rating (MVA)			664.1	664.1	664.1	664.1	538.2	541.4
	Max	P0	System Normal	17.88	11.67	14.62	14.43	39.72	46.55
	Max	P1.2	2L392_A	---	29.58	26.61	2.81	34.46	51.43
	Max	P1.2	2L392_B	29.58	---	6.92	22.31	43.19	43.32
	Max	P1.2	2L391	17.88	11.68	---	---	39.72	46.55
	Max	P1.2	2L312	3.95	25.62	1.48	28.37	---	83.48
	Max	P2.3	SBK_1CB4	17.69	11.89	14.40	14.65	39.70	46.56
	Max	P2.2	5L5	15.15	14.40	12.11	17.12	34.60	51.40
	Max	P2.2	5L6	15.10	14.46	12.06	17.18	34.50	51.50
32HS	Summer Rating (MVA)			535	535	535	535	424.7	427.5
	Max	P0	System Normal	26.55	11.47	22.46	14.92	50.70	62.50
	Max	P1.2	2L392_A	---	37.70	40.31	6.03	42.75	70.08
	Max	P1.2	2L392_B	36.91	---	15.58	22.17	54.02	59.54
	Max	P1.2	2L391	21.32	16.20	---	---	58.18	54.97
	Max	P1.2	2L312	9.44	27.97	5.47	31.42	---	109.08 [6]
	Max	P2.3	SBK_1CB4	26.32	11.70	22.23	15.14	50.66	62.55
	Max	P2.2	5L5	22.90	15.07	18.98	18.30	43.89	69.14
	Max	P2.2	5L6	22.83	15.14	18.91	18.37	43.75	69.27
32LS	Summer Rating (MVA)			535	535	535	535	424.7	427.5
	Max	P0	System Normal	27.61	9.09	23.66	12.51	46.96	65.27
	Max	P1.2	2L392_A	---	36.78	42.12	6.65	38.72	72.99
	Max	P1.2	2L392_B	36.68	---	17.70	18.60	49.69	62.73
	Max	P1.2	2L391	23.04	13.67	---	---	54.28	58.18
	Max	P1.2	2L312	11.59	25.20	7.93	28.58	---	108.81 [6]
	Max	P2.1	SBK_1CB4	27.47	9.26	23.46	12.68	46.94	65.28
	Max	P2.2	5L5	23.99	12.76	20.28	16.10	40.03	71.87
	Max	P2.2	5L6	23.91	12.84	20.21	16.18	39.88	72.00

Notes:
[1] P1.2, P2.1 and etc. are the contingency categories defined in NERC TPL-001-4.
[2] 2L392-A is the line between SBK to [redacted] Terminal Station (TYTX).
[3] 2L392-B is the line between [redacted] Terminal Station (TYTX) to SGB.
[4] 2L391-A is the line between SBK to POI.

[5] 2L391-B is the line between POI to SGB.
[6] These are existing overloads and are currently addressed by Peace Region generation shedding RAS.

Table B-2: Selected Bus Voltages in Base Study Scenarios

Case	IC's Plant Output	Contingency		Bus Voltage (pu)			
		Cat.	Description	SKD_POI	SGB 230	SLS 230	SNK 230
31HW	Max	P0	System Normal	1.0350	1.0331	1.0334	1.0344
	Max	P1.2	2L392_A	1.0350	1.0328	1.0333	1.0340
	Max	P1.2	2L392_B	1.0350	1.0325	1.0325	1.0343
	Max	P1.2	2L391	--	1.0331	1.0334	1.0344
	Max	P1.2	2L312	1.0350	1.0330	1.0336	1.0257
	Max	P2.3	SBK_1CB4	1.0350	1.0332	1.0336	1.0345
	Max	P2.3	5L5	1.0350	1.0330	1.0336	1.0336
	Max	P2.3	5L6	1.0350	1.0330	1.0336	1.0336
32HS	Max	P0	System Normal	1.0370	1.0444	1.0437	1.0385
	Max	P1.2	2L392_A	1.0370	1.0442	1.0437	1.0384
	Max	P1.2	2L392_B	1.0370	1.0465	1.0455	1.0391
	Max	P1.2	2L391	--	1.0426	1.0419	1.0377
	Max	P1.2	2L312	1.0370	1.0428	1.0434	1.0255
	Max	P2.3	SBK_1CB4	1.0370	1.0444	1.0438	1.0385
	Max	P2.3	5L5	1.0370	1.0440	1.0433	1.0379
	Max	P2.3	5L6	1.0370	1.0440	1.0433	1.0379
32LS	Max	P0	System Normal	1.0370	1.0352	1.0356	1.0349
	Max	P1.2	2L392_A	1.0370	1.0350	1.0354	1.0342
	Max	P1.2	2L392_B	1.0370	1.0352	1.0356	1.0350
	Max	P1.2	2L391	--	1.0341	1.0346	1.0350
	Max	P1.2	2L312	1.0370	1.0360	1.0368	1.0247
	Max	P2.3	SBK_1CB4	1.0370	1.0354	1.0358	1.0350
	Max	P2.3	5L5	1.0370	1.0353	1.0358	1.0342
	Max	P2.3	5L6	1.0370	1.0353	1.0358	1.0341

Appendix C
Transient Stability Study Results

There is no transient instability or transient voltage recovery violation identified in the SIS. A summary of the transient stability study results for 2031HW, 2032HW, and 2032LS load conditions with [redacted] project is provided in the table below.

Table C-1: Transient Stability Study Results (2031HW, 2032HW, 2032LS Scenarios)

Category	Contingency	Fault Location	Fault Clearing Time (Cycles)		[redacted] Project Performance	Other Generators in the study area
			Close End	Far End		
P1.2	5L1	Close to GMS	4	4	Acceptable	Acceptable
P1.2	5L3	Close to PCN	4	4	Acceptable	Acceptable
P1.2	5L4	Close to PCN	4	4	Acceptable	Acceptable
P1.2	5L5	Close to SBK	4	4	Acceptable	Acceptable
P1.2	5L6	Close to SBK	4	4	Acceptable	Acceptable
P1.2	5L15	Close to STC	4	4	Acceptable	Acceptable
P1.2	2L391	Close to SBK	6	7	Acceptable	Acceptable
P1.2	2L391	Close to SGB	6	7	Acceptable	Acceptable
P1.2	2L392_A	Close to SBK	6	7	Acceptable	Acceptable
P1.2	2L392_B	Close to SBG	6	7	Acceptable	Acceptable
P1.2	2L392_C [1]	Close to TAW	6	7	Acceptable	Acceptable
P1.2	2L340	Close to SGB	6	7	Acceptable	Acceptable
P1.2	2L329	Close to BMT	6	7	Acceptable	Acceptable
P1.2	1L348	Close to DAW	9	10	Acceptable	Acceptable
P1.3	BMT_T1	BMT 230 kV	11	11	Acceptable	Acceptable
P1.3	SBK_T11	SBK 500 kV	6	6	Acceptable	Acceptable

P4	Stuck Breaker_SBK_1CB1 fault @SBK_1L374	Close to SBK	17	7	Acceptable	Acceptable
P4	Stuck Breaker_SBK_1CB2 fault @SBK_1L360	Close to SBK	18	5	Acceptable	Acceptable
P4	Stuck Breaker_SBK_2CB13 fault @SBK_2L391	Close to SBK	14	7	Acceptable	Acceptable
P4	Stuck Breaker_SBK_2CB22 fault @SBK_2L392	Close to SBK	14	7	Acceptable	Acceptable
P4	Stuck Breaker_SGB_2CB4 fault @SGB_2L391	Close to SGB	14	7	Acceptable	Acceptable
P4	Stuck Breaker_SGB_2CB5 fault @SGB_2L392	Close to SGB	14	7	Acceptable	Acceptable
P4	Stuck Breaker_SGB_2CB5 fault @BMT_2L329	Close to BMT	6	15	Acceptable	Acceptable
P4	Stuck Breaker_BMT_2CB11 fault @BMT_2L329	Close to BMT	14	7	Acceptable	Acceptable
P4	Stuck Breaker_SLS_2CB11 fault @SLS_2L312	Close to SLS	14	6	Acceptable	Acceptable
P4	Stuck Breaker_SNK_2CB12 fault @SNK_2L312	Close to SNK	14	6	Acceptable	Acceptable
P4	Stuck Breaker_TAW_2CB2 fault @TAW_2L392	Close to TAW	14	6	Acceptable	Acceptable
P4	Stuck Breaker_TAW_2CB3 fault @TAW_2L392	Close to TAW	14	6	Acceptable	Acceptable
Note: [1] The proposed customer-built 230 kV line (TYTX-TAW) for the other successful project [redacted] (TAW) will be designated as 2L392_C.						

Appendix D
Power Flow and Dynamic Models and Data

All WTGs connected to the same feeder are represented by one equivalent generator in power flow cases with the following data:

[redacted]

[redacted]

Appendix E

Transmission Line Diagrams

The POI location of [redacted] project on lines 2L391 is provided in this appendix.

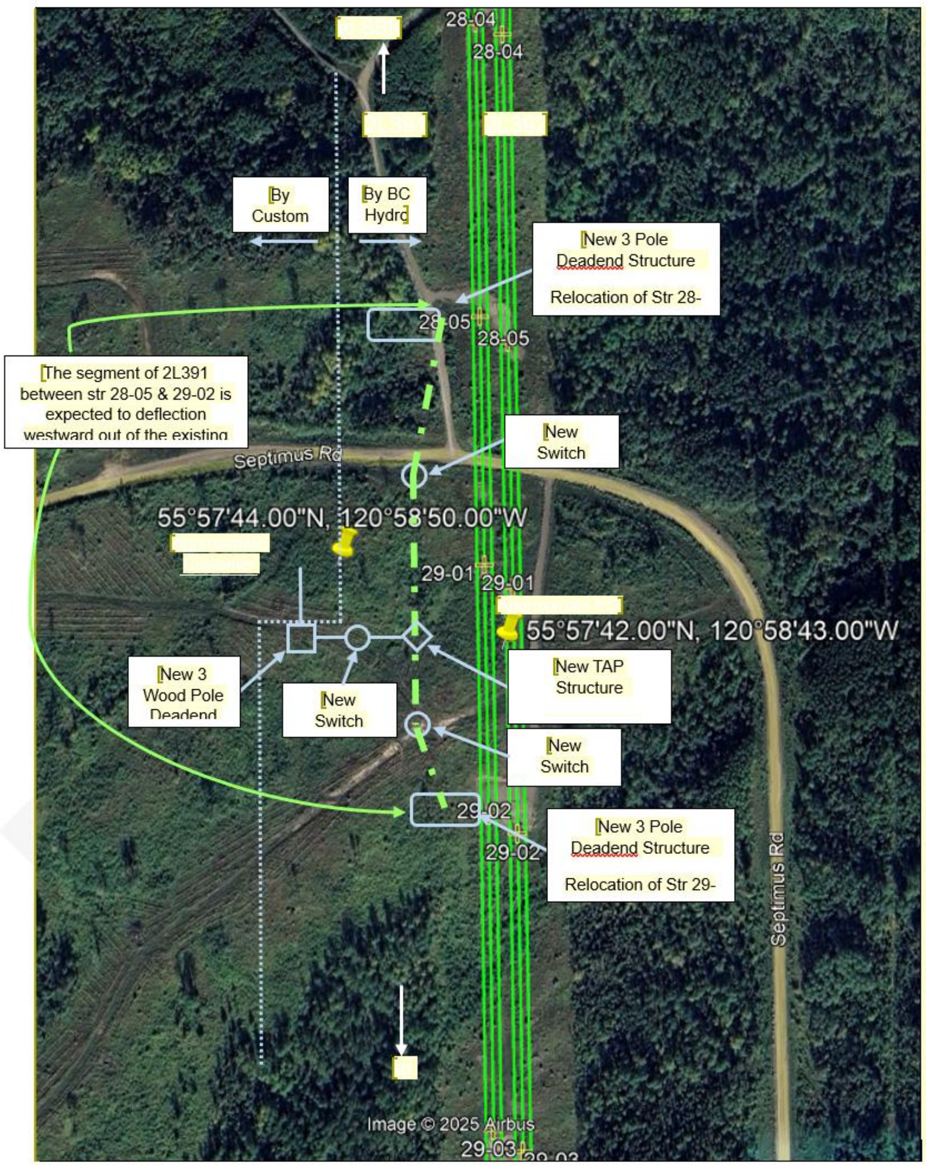

Figure E-1: 2L391 POI (28 km from South Bank SBK).

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 and RAS Requirements for Telecom

- Provide WECC Level 3 64 kbps synchronous circuits between SBK and SKD for “SBK-SKD 2L391 PY/SY Digital Teleprot”.
- Provide WECC Level 3 64 kbps synchronous circuits between SGB and SKD for “SGB -SKD 2L391 PY/SY Digital Teleprot”.
- Provide WECC Level 1 transfer trip facilities from SBK to SKD for “SBK PY/SY G/S TT to SKD”.
- Retain existing WECC Level 3 64 kbps synchronous circuits between SBK and SGB for “SBK- SGB 2L391 PY/SY Digital Teleprot”. If a signal name change is required, update applicable configurations and records.

Telecontrol Requirements for Telecom

- Provide a SKD SCADA channel.
- Provide TYTX SCADA, REMACC, and PML channels.

Other Requirements for Telecom

- Install multiple MPLS Links and other telecom circuits in BCH’s network.

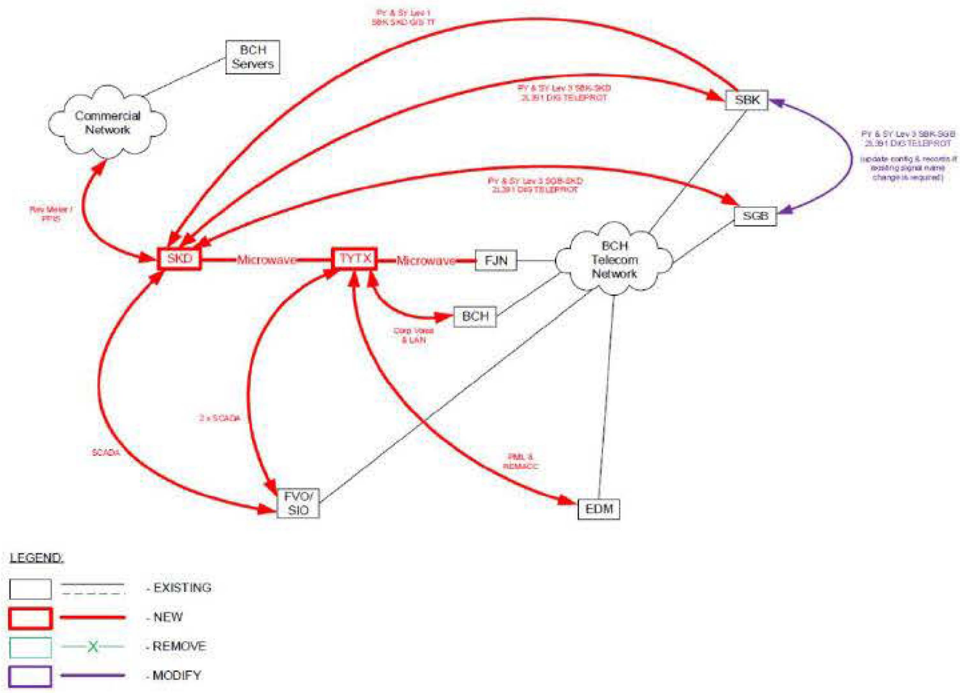

Figure F-1: The telecom block diagram identified in SIS of [redacted] Project.

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 [redacted] Plant and the Telecommunications Service Provider. The [redacted] Plant is required to provide terminals or connectors 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 (GPR) 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. 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, 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.