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

August 8, 2025

[redacted]

[redacted]

Dear [redacted]

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

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 **$98.2 M.** 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 – New 230kV Switching Station (NETX):

- Acquire adequate property close to the existing transmission line 2L096 and construct the new [redacted] (NETX) 230kV 3-circuit breaker ring switching station.

Transmission Line Scope

- Re-terminate line 2L096 near the POI to the new switching station and install up to three 230kV 3-pole dead-end structures for each side of the re-termination.

- A dead-end structure should be installed as a demarcation point between the Customer owned 230kV line and the BC hydro owned portion of the line.

Protection and Control Scope at Barlow Substation (BLW), Red Bluff Substation (RBF), Southbank Substation (SBK), Soda Creek Substation (SCK) and the new NETX Switching Station, as well as others; scope includes:

- Modifications/additions to the local Load Shedding Remedial Action Scheme (RAS), updating/providing protection relays and installing the full scope of control systems at NETX.

Telecom Scope at BLW, RBF, SBK, SCK, NETX, and other microwave stations and substations, including:

- Installing/adding routing nodes and equipment, towers, antennas, battery and charger requirements, microwave radio systems, routers and firewalls, and tele-protection terminals.

Exclusions:

- GST
- Book value of decommissioned equipment
- Outage costs (lost revenue)
- Cost change due to currency fluctuations.
- Permits
- Potential property impacts (see Key Assumptions below for more information).
- As the exact project location is unknown, site-specific requirements including but not limited to dewatering, ground improvements, slope stabilization, etc. are not included.

Key Assumptions:

- Partial Implementation project phase shall be used to accelerate the purchase of circuit breakers.
- Project is considered greenfield, outside of work around existing Transmission lines (taps, in-out reconfigurations, etc.).
- 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.
- BC Hydro's Contractor to assume Prime Contractor responsibility.
- 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.
- Properties & ROW costs assume that 4 hectares of Crown land are required for the switching station and interconnection. No in-depth market transaction research has been conducted on land values, which may vary significantly depending on location, amenities, and market conditions.
- The ultimate 7 circuit breaker switching station standard has been considered for properties, grounding, and civil (excluding foundations).
- Environmental Assessment Certificate will not be required for this project.
- Temporary camp for construction will not be required.
- Station and Control room expansions are not triggered by this Interconnection Request.
- Customer to design and build last span. BC Hydro to review and approve design.
- Station location assumed to be within 500m of a viable access highway/road.
- Outage window needed to reconfigure the 230kV line will be accepted by BC Hydro Operations.
- Some portion of the existing line will need to be decommissioned which will involve removing some conductor, hardware, and up to two existing structures.
- At BLW, SCK, TBR, and DGN: 48VDC battery and charger requirements are assessed and no upgrades are required.

Key Risks:

- Delays in receiving documentation or funding from the Interconnection Customer which may delay key milestones.
- Major Equipment delivery presents potential project cost and schedule risks, based on variance in equipment lead times.
- No defined supply chain strategy at this stage.
- Cost of construction may increase based on geotechnical conditions and environmental conditions at the actual project site.
- Project schedule may be longer than expected, leading to increased loading costs.
- Cost of materials and major equipment may be affected by market conditions and escalation.
- Telecom scopes can present higher cost risk due to rapidly evolving technologies and standards.
- No in-depth market transaction research has been conducted on land values, which may vary significantly depending on location, amenities, and market conditions.
- Additional right of way may be required to accommodate the ingress and egress of the line.

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 3, 2031** 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. 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 you to provide your confirmation to proceed with the Facilities Study in writing.

In addition to the confirmation, you will be required to provide the deposit for the Facilities Study, as well as any other additional data that may be necessary.

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

Sincerely,

[redacted]

[redacted]

Interconnections Manager, Transmission Generator Interconnections

BC Hydro

Encl.: [redacted] **System Impact Study.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]
Specialist Engineer, Powertech Labs Inc.

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

Accepted by: [redacted]
Manager, Transmission Planning

Report Metadata

Header:	[redacted]
Subheader:	Interconnection System Impact Study
Title:	
Subtitle:	[redacted]
Report Number:	830C-APR-00001
Revision:	0
Confidentiality:	Public
Date:	2025 Aug 06
Volume:	1 of 1
Prepared for:	[redacted]
Prepared by:	[redacted]
Title:	Specialist 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 – NEC Line designation – 2L96
Additional Metadata:	Transmission Planning 2025-022 Filling subcode 1350

Revisions

Revision	Date	Description
0	2025 Aug	Initial release

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Section: Discipline:

The entire report except those listed below — Interconnection Planning

Contributed by: [redacted] [redacted]

Specialist Engineer, Powertech Labs Inc.

Section: Discipline:

5.7 [redacted]

Contributed by: [redacted]

Specialist Engineer, Substations Growth and Sustainment

Section: Discipline:

5.8 [redacted]

Contributed by: [redacted]

Senior Engineer, Transmission Line Engineering

Section:	Discipline:	
5.9.1&5.9.2	[redacted]	[redacted]
Contributed by:	Specialist Engineer, Transmission P&C Engineering	

Section:	Discipline:	
5.6	[redacted]	[redacted]
Contributed by:	Specialist Engineer, Transmission Operations Services	

Section:	Discipline:	
5.4	[redacted]	[redacted]
Contributed by:	Team Lead, Substations Growth and Sustainment	

Section:	Discipline:	
5.9.3	[redacted]	[redacted]
Contributed by:	Specialist Engineer, Telecom Planning & Asset Management	

Section: 7

Discipline: [redacted]

Contributed by: [redacted]

Specialist Engineer, Revenue Metering [redacted]

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Acronyms

The following are acronyms used in this report.

BCH	British Columbia Hydro and Power Authority
BLW	Barlow Substation
COD	Commercial Operation Date
CT	Current Transformer
DFR	Digital Fault Recorder
DTT	Direct Transfer Trip
EMS	Energy management System
ERIS	Energy Resource Interconnection Service
FRT	Fault Ride-Through
HS	Heavy Summer Load Condition
HW	Heavy Winter Load Condition
IC	Interconnection Customer
IP	Internet Protocol
IPO	Independent Pole Operated
ISD	In-Service Date
KLY	Kelly Lake Substation
LS	Light Summer Load Condition
MC	Measurement Canada or Canada Federal Regulations
MPO	Maximum Power Output
NEC	[redacted] Project
NETX	[redacted] Project Switching Station
NERC	North American Electric Reliability Corporation
NRIS	Network Resource Interconnection Service
OOS	Out of Service
PODR	Point of Delivery Reference
POI	Point of Interconnection

POM Point of Metering

PPC Power Plant Controller

PPIS Power Parameter Information System

RAS Remedial Action Scheme

RBF Red Bluff Substation

SBK South Bank Substation

SCK Soda Creek Substation

SIS System Impact Study

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

TOV Temporary Overvoltage

VT Voltage Transformer

WECC Western Electricity Coordinating Council

WSN Williston Substation

WTG Wind Turbine Generator

Executive Summary

[redacted], the Interconnection Customer (IC), requests to connect its [redacted] Project into the BCH system in the Central Interior Region of the province.

The [redacted] Project has [redacted] wind turbine generators (WTGs), each rated at 8.2 MW with a power factor of 0.9. Each turbine will have a maximum active power output of 8.0 MW and the total installed capacity of the project will be approximately 144 MW. The maximum power injection at the proposed Point of Interconnection (POI) is 140.4 MW.

The proposed POI is located on BC Hydro's existing 230 kV transmission line 2L96, approximately 43 km from Barlow Substation (BLW). The proposed commercial operation date (COD) is September 30, 2031. The IC's project will build a 25 km long, 230 kV interconnection line from the IC's step-up substation (referred to as "NEC") to the proposed POI.

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

1. A new 230 kV switching station (temporarily referred to as "NETX") on the BCH's existing circuit 2L96 is required at or close to the proposed POI for interconnecting the IC's generating project to the BCH system. With the new switching station NETX, 2L96 will be segregated into two new lines, temporarily referred to as 2L96_A (WSN-NETX) and 2L96_B (NETX-BLW). The proposed customer-built 230 kV line (NETX-NEC) for connecting the project will be temporarily designated as 2L96_C and the IC's step-up substation is referred to as "NEC".

2. The proposed [redacted] Project can meet the dynamic reactive power capability requirement specified in the BC Hydro's TIR Section 6.4.2 over the entire MW operating range.

3. The turbines of the [redacted] Project are required to have fault ride-through (FRT) capabilities per BCH's TIR. Using the default settings provided, the fault ride-through performance of the inverters 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.

4. BCH will provide line protections for 2L96_A, 2L96_B and 2L96_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.

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 Direct Transfer Trip (DTT) scheme is required in accordance with IEEE Std 2800-2022. This DTT scheme will initiate a trip to the [redacted] Plant for any protection tripping or manual opening of both lines in the following combinations: 2L96_A & 2L96_B, 2L96_A & 2L354, and 2L96_A & 2L95.

7. Fast Frequency Response, also known as Virtual Inertia Control (VIC) in wind turbines, 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.

8. [redacted] Project is required to participate in the existing GMS Area Generation Shedding RAS for 500 kV contingencies in south of WSN transmission system to provide operational flexibilities and reduce operational restrictions.

9. The connection of the [redacted] Project in the Central Interior Region does not cause any system performance violations (i.e. thermal overload, voltage violation, voltage instability, etc.) under system normal and contingency conditions.

10. Voltage sags caused by energization of the substation main transformer exceed the limits specified in BC Hydro's TIR. The IC is required to use point-on-wave (POW) controlled closing with independent pole operated (IPO) 230 kV circuit breakers for mitigating the transformer inrush current.

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 into the BCH system. The [redacted] Project has [redacted] wind turbine generators (WTGs), each rated 8.2 MW at a power factor of 0.9. Each turbine will have a maximum active power output of 8.0 MW and the total installed capacity of the project will be approximately 144 MW. The maximum power injection at the proposed Point of Interconnection (POI) is 140.4 MW.

The proposed POI is located on BC Hydro's existing 230 kV transmission line 2L96, approximately 43 km from Barlow Substation (BLW). The proposed commercial operation date (COD) is September 30, 2031. The project overview is provided in Table 1-1.

Table 1-1: Summary of Project Information

Project Name	[redacted]	
Name of Interconnection Customer (IC)	[redacted].	
IC Proposed Point of Interconnection	A point on 2L96, 43 km from BLW	
IC Proposed COD	September 30, 2031	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW) at POI	140.4 (Summer)	140.4 (Winter)
Number of Generator Units	[redacted] Wind Turbine Generators	
Plant Fuel	Wind	

There are four (4) feeders in the plant and each turbine generator is connected to one of the feeders through its nacelle-mounted transformer with voltage being stepped up to 34.5 kV. These 34.5 kV feeders are further connected to the BCH's 230 kV transmission system via one main power transformer and an IC-owned 25 km, 230 kV interconnection line. The IC's 230 kV main substation is referred to as "NEC" in this report.

Figure 1-1 illustrates the connection of [redacted] Project to the Central Interior Region transmission system where Williston Substation (WSN) is a major transmission hub that connects to Peace Region and North Coast transmission systems. WSN has three voltage levels (500 kV, 230 kV and 66 kV) and connects to the following circuits:

- Seven 500 kV lines 5L1, 5L2, 5L7, 5L11, 5L12, 5L13 and 5L61.
- Two 230 kV lines 2L96 and 2L97.
- Several 66 kV lines that normally operated as radial networks (not parallelled with 230 kV or 500 kV network).

As shown in the diagram, the south of Williston cut plane (consisting of four circuits 5L11, 5L12, 5L13 and 2L96) is a major transfer path directly associated with the interconnection of the IC's wind generating project.

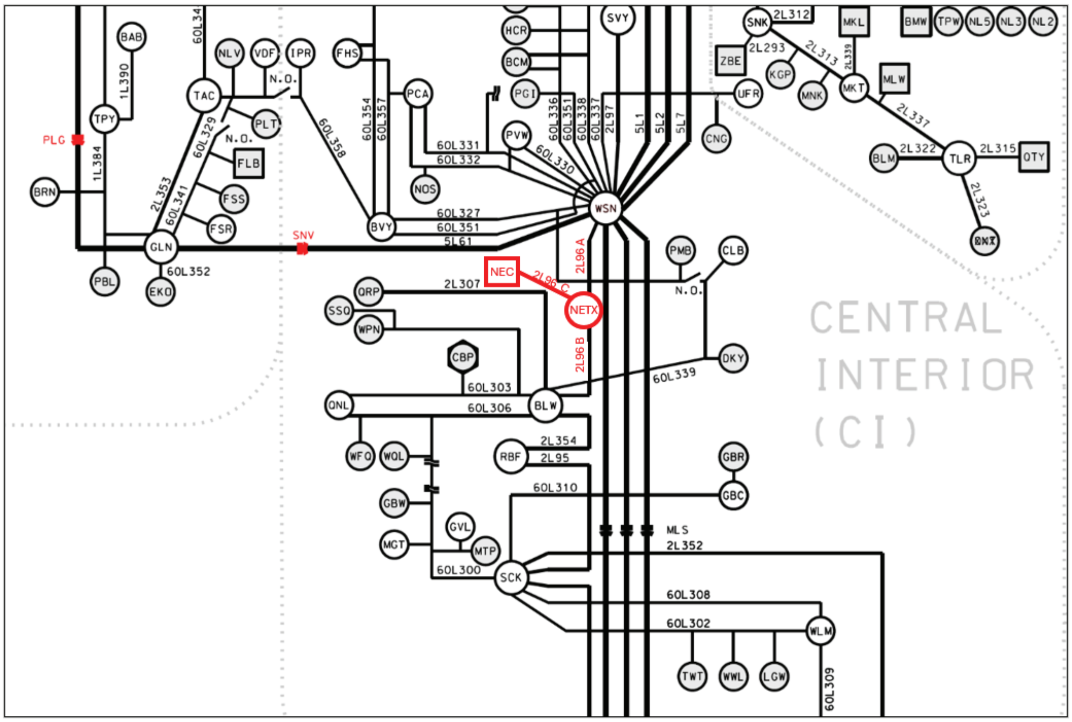

Figure 1-1: Central Interior Region Transmission System with [redacted] Project Addition

Appendix A shows the plant-level 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 11, 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 2024 power call projects relevant to the proposed interconnection 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.
- The regional generation 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.
- The plant controller model parameters of the [redacted] project are finetuned (i.e. lowering the Ki gain in the REPC_A model) to ensure a stable and acceptable dynamic performance under contingency conditions.

5 System Studies and Results

Based upon the IC's submitted information and the area system conditions, a new three-circuit-breaker-ring switching station (referred to as "NETX") at the proposed POI on 2L96 is required to interconnect the [redacted] 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 project addition.

With the new switching station NETX, 2L96 will be segregated into two new lines, temporarily referred to as 2L96_A (WSN-NETX) and 2L96_B (NETX-BLW). The proposed customer-built 230 kV line (NETX-NEC) for connecting the project will be temporarily designated as 2L96_C. The temporary line designations will be replaced by permanent designations 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 for the study cases based on the assumptions and considerations outlined in Section 4. The selected 2031 HW, 2032 HS and 2032 LS load conditions are studied with higher Peace generation and lower Columbia generation dispatch conditions. Appendix B contains the key results of power flow studies for these scenarios studied in this SIS.

Based on the study results, there is no overload or voltage violation observed in the studied area under system normal conditions. No overload or voltage violation was observed under the studied contingencies due to the connection of [redacted] Project.

BCH TIR requires Inverter Based Resource (IBR) power plant to have the dynamic reactive power capability at a minimum of +/- 33% of its MPO from the plant at the high-voltage side of the switchyard over the full MW operating range. The simulation results for the [redacted] Project indicate that the project meets the reactive capability requirements over the entire MW operating range (from full to lower and zero MW output).

5.2 Transient Stability Study

Transient stability studies have been performed using the 2031 HW and 2031 HS and 2032LS 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.

The IC provided dynamic models showed some oscillations during post-contingency recovery under various contingencies. Therefore, the dynamic simulation was performed with the wind farm model finetuned (i.e. lowering the integral gain Ki value in the power plant model) to obtain a stable output from the [redacted] Project. With the finetuned power plant controller parameters, no transient stability was observed in the area under the study contingencies.

Besides, upon the IC's submission, the WTG at [redacted] Project can provide fast frequency response (FFR) if the turbine's optional Virtual Synchronous Machine Controller is enabled. The FFR function is required at [redacted] Project to limit the system frequency drop during a major frequency event. The FFR settings should be determined in coordination with BC Hydro in the later stage of interconnection studies.

Appendix C shows a summary of the transient stability study results for 2031HW, 2031HS and 2032LS with the addition of [redacted] Project.

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:

- Anti-islanding protection is required for the [redacted] Project. A telecommunication-based Direct Transfer Trip (DTT) scheme is recommended in accordance with IEEE Std 2800-2022. The DTT scheme will initiate a trip to the [redacted] Plant for any protection tripping or manual opening of both lines in the following combinations: 2L96A & 2L96B, 2L96A & 2L354, and 2L96A & 2L95.
- Voltage disturbance resulting from energization of the 230/34.5 kV main

power transformer was studied under system normal and contingency conditions. The voltage sags exceed the limit specified in BC Hydro's TIR. The IC is required to use point-on-wave (POW) controlled closing with independent pole operated (IPO) 230 kV circuit breakers for mitigating the transformer inrush current.

- The risk of temporary overvoltages (TOVs) was assessed under the unintentional islanding condition. Islanding occurs when [redacted] Project 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.
- The harmonic current injection from [redacted] Project shall not exceed the limits specified in TIR, which follows IEEE Std 519-2022. Harmonic studies will be conducted at a later stage when the spectrum of harmonic current injection from the wind farm becomes available.
- Electromagnetic Transient (EMT) model is parameterized with the voltage and frequency ride-through settings that meets TIR requirements. BC Hydro may follow up on this topic during the pre-commissioning stage.
- The EMT responses of [redacted] Project, including the active power control, reactive power control, and dynamic active power support under abnormal frequency conditions, are acceptable in accordance with the facility's electrical and control requirements.
- Power system contingencies were evaluated to identify the lowest credible short circuit ratios (SCRs) of the wind generating plant at the Point of Interconnection (POI). The [redacted] Project demonstrated stable operation under reduced SCR of approximately 5.0.

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 order to secure the transmission system south of WSN under various operating conditions and meet system reliability performance requirements, the [redacted] Project is required to participate in the existing GMS Area Generation Shedding RAS for 500 kV contingencies in south of WSN transmission system.

5.7 Station Upgrade Requirements

The station upgrade requirement for [redacted] Project Terminal switching station (NETX) work are as follows:

- Acquire adequate property for a new [redacted] (NETX) switching station close to the existing transmission line 2L096. The property shall be chosen considering the ultimate stage of NETX switching station.
- Construct a new outdoor 230 kV, 3-circuit breaker ring bus switching station. Three circuit breakers (2CB1, 2CB2 and 2CB3) and associated disconnects shall be 3000A rated.
- Install three 230kV line terminals associated motorized disconnects, Surge Arresters and Capacitor Voltage Transformers for the transmission lines 2L096_A, 2L096_B and 2L096_C (these lines designations shall be finalized at later stage).
- Install two single phase 230kV station service VTs, 2SSVT1 and 2SSVT2.
- Install one set of diesel generator for station service backup.
- Construct a new control building and other required substation facilities.
- Install associated station service, P&C, Telecom, SCADA, and mechanical equipment including fire detection/extinguishing devices.
- Construct station ground system and other necessary equipment and facilities required for new NETX switching station.

The [redacted] Project Terminal switching station (NETX) one-line diagram 230 KV switching station is shown in Appendix E.

5.8 Transmission Line Upgrade Requirements

The transmission line engineering scope of work for this project is identified as below:

- Re-terminate line 2L96 at approximately Structure 218-01 (POI) to the new switching station NETX forming a new section 2L96_A, and at approximately structure 217-07 (POI) to the new switching station NETX, forming a new section 2L96_B. It will require up to three 230kV 3-pole dead-end structures for each portion of the re-termination. The exact circuit numbers will be determined at a later stage.

- Additional right of way may be required to accommodate the ingress and egress of the line.
- Some portion of the existing line may need to be decommissioned which will involve removing some conductor, hardware and existing structure.
- Install a dead-end structure to demarcate the customer-owned 230 kV line from BC Hydro's portion; BC Hydro will design and build the last span into NETX or perform the BCH's review if the customer builds it. If customer would like to design and build the last span from 2L96_C to NETX switching station, BC Hydro will perform the review for this design.
- Assuming the customer will furnish, install, and own a single mode fibre optic cable (minimum 48 F) between NETX and NEC along the 2L96_C transmission structures. BC Hydro will design and built the transition of this fibre cable from the last transmission structure of 2L96_C to a conduit/trench connected to the control building of NETX. If the customer would like to design and build it, BCH will perform the OE review.

5.9 Protection, Control and Telecommunications

5.9.1 Protection

The [redacted] Project will be required to participate in the GMS Area Gen Shed RAS Scheme (via tripping of 2L96_C at NETX). An anti-islanding Direct Transfer Trip (DTT) to the Nihlts'I Ecoener Wind Project is required for protection trips or manual opening of both lines in the following combinations: 2L96_A & 2L96_B, 2L96_A & 2L354, and 2L96_A & 2L95. BC Hydro will provide line protections for 2L96_A, 2L96_B and 2L96_C protections. As part of the line protection replacements for each of the three lines, telecommunication facilities will be required to accommodate the new protection schemes.

Additional work will be required at BLW, RBF, SBK, SCW and WSN substations to implement the anti-islanding requirements as per Section 5.4. GMS Area Gen Shed RAS changes will be required at SBK to implement the RAS requirements as per Section 5.6.

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 two SEL-411L-1 relays (firmware and options specified by BC Hydro) relays at the entrance of the IC’s step-up substation NEC. BC Hydro P&C Planning will provide core settings for these relays.
- 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 line protection relays and Power Parameter Information System (PPIS) equipment by BCH servers.
- Provide anti-islanding protection as per Section 5.4.

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 is responsible for providing an appropriate 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.

NETX switching station shall receive a new control system as part of this project.

Minor work will be required by BC Hydro to recommission telemetry, alarms, and remote access at WSN, BLW for the new protection relays. Additional work is required at RBF, SBK and SCK for remote access, alarm and DFR changes.

5.9.3 Telecommunications

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

Telecom System Upgrade/Extension

- Implement a NETX-RRK microwave radio link. Implement an RRK-TBR microwave radio overbuild. Perform a tower study at RRK and TBR. Reinforce or build a new tower, if required. Build a new tower at NETX.
- Terminate a fibre optic cable (from NEC) at NETX.

IC's Work Required at NEC

- Install a single-mode fibre optic cable (minimum 48 F) between NEC and NETX; install a 48 V DC power supply with 8 hours of reserve; install redundant MPLS nodes and connect to fibre from NETX; integrate the NETX C37.94 digital teleprotection circuits and the SCADA circuit into the MPLS system.

BCH's Work Required at NETX

- Install a tower and antenna facing RRK; Install an 11 GHZ (if possible, otherwise 7 GHz), dual shelf, microwave radio system facing RRK and other telecom equipment. Implement various telecom circuits.

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

- NETX is assumed located at 53° 22’ 58.08” N, 122° 36’ 37.08” W.
- NEC is assumed located at 53° 25’ 21” N, 122° 19’ 60” W.
- The microwave radio communications between NETX-RRK are possible.
- the Revenue Metering / PPIS circuit(s) required at NEC 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 (Measurement Canada or 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. The MC approved revenue class instrument transformers (CTs and VTs units) are supplied by BCH (Stock items w/CAT ID).

- 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 identified the following requirements and conclusions:

1. A new 230 kV switching station (temporarily referred to as “NETX”) on the BCH’s existing circuit 2L96 is required at or close to the proposed POI for interconnecting the IC’s generating project to the BCH system. With the new switching station NETX, 2L96 will be segregated into two new lines, temporarily referred to as 2L96_A (WSN-NETX) and 2L96_B (NETX-BLW). The proposed customer-built 230 kV line (NETX-NEC) for connecting the project will be temporarily designated as 2L96_C and the IC’s step-up substation is referred to as “NEC”.

2. The proposed [redacted] Project can meet the dynamic reactive power capability requirement specified in the BC Hydro’s TIR Section 6.4.2 over the entire MW operating range.

3. The turbines of the [redacted] Project are required to have fault ride-through (FRT) capabilities per BCH’s TIR. Using the default settings provided, the fault ride-through performance of the inverters 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.

4. BCH will provide line protections for 2L96_A, 2L96_B and 2L96_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.

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 Direct Transfer Trip (DTT) scheme is required in accordance with IEEE Std 2800-2022. This DTT scheme will initiate a trip to the [redacted] Plant for any protection tripping or manual opening of both lines in the following combinations: 2L96_A & 2L96_B, 2L96_A & 2L354, and 2L96_A & 2L95.

7. Fast Frequency Response, also known as Virtual Inertia Control (VIC) in wind turbines, 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.

8. [redacted] Project is required to participate in the existing GMS Area Generation Shedding RAS for 500 kV contingencies in south of WSN transmission system to provide operational flexibilities and reduce operational restrictions.

9. The connection of the [redacted] Project in the Central Interior Region does not cause any system performance violations (i.e. thermal overload, voltage violation, voltage instability, etc.) under system normal and contingency conditions.

10. Voltage sags caused by energization of the substation main transformer exceed the limits specified in BC Hydro's TIR. The IC is required to use point-on-wave (POW) controlled closing with independent pole operated (IPO) 230 kV circuit breakers for mitigating the transformer inrush current.

Appendix A

Schematic Diagram of [redacted] Project

Figure A-1 shows the plant schematic diagram for the project based on IC submitted data

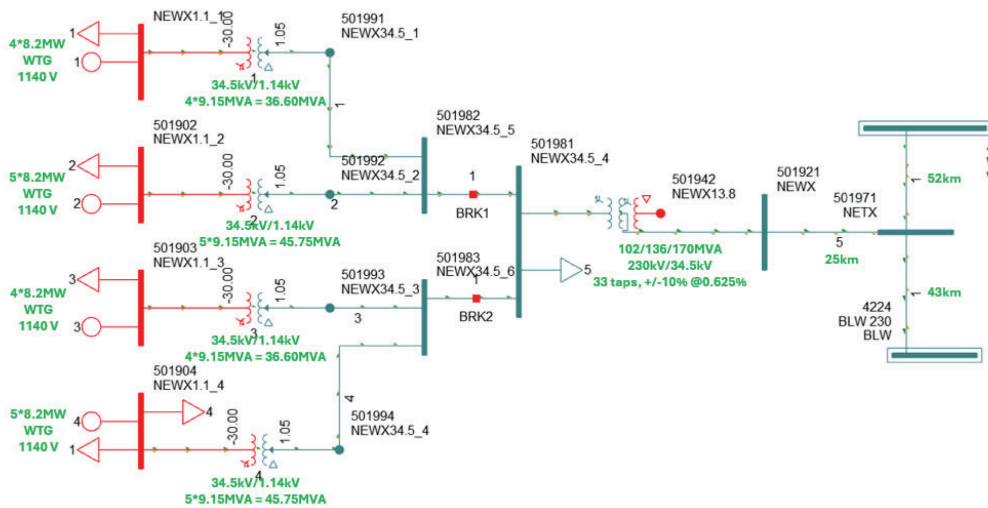

Figure A-1: Schematic Diagram of [redacted] Project

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Appendix B
Power Flow Study Results

There is no thermal overload and voltage violation identified in the SIS. Table B-1 and Table B-2 show the key results of power flow studies for the study scenarios.

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

Case	IC's Plant Output	Contingency		Branch Loading				
		Category	Description	2L96_A	2L96_B	2L354	2L95	WSN T4
31HW	Winter Rating (MVA)			471.7	471.7	318.7	318.7	1425.0
	Max	P0	N/A	19%	50%	47%	36%	12%
	Max	P1.2	2L96_A	-	32%	21%	10%	9%
	Max	P1.2	2L96_B	31%	-	25%	37%	6%
	Max	P1.2	2L94	17%	47%	44%	33%	12%
	Max	P1.2	5L11 (Note 1)	32%	60%	63%	52%	14%
	Max	P2.3	KLY_5CB1 (Note 1)	34%	62%	66%	55%	14%
	Max	P2.3	WSN_2CB7	-	32%	21%	10%	-
	Max	P2.3	BLW_2CB4	31%	-	-	13%	6%
32HS	Summer Rating (MVA)			325.5	325.5	228.7	205.2	1200.0
	Max	P0	N/A	23%	67%	61%	56%	12%
	Max	P1.2	2L96_A	-	45%	30%	21%	8%
	Max	P1.2	2L96_B	45%	-	33%	49%	5%
	Max	P1.2	2L94	18%	61%	53%	47%	11%
	Max	P1.2	5L11 (Note 1)	42%	83%	85%	82%	14%
	Max	P2.3	KLY_5CB1 (Note 1)	45%	86%	88%	86%	14%
	Max	P2.3	WSN_2CB7	-	45%	30%	21%	-
	Max	P2.3	BLW_2CB4	45%	-	-	12%	5%
32LS	Summer Rating (MVA)			325.5	325.5	228.7	205.2	1200.0
	Max	P0	N/A	14%	56%	52%	50%	7%
	Max	P1.2	2L96_A	-	43%	34%	30%	5%
	Max	P1.2	2L96_B	44%	-	27%	37%	3%
	Max	P1.2	2L94	9%	50%	43%	41%	6%
	Max	P1.2	5L11	28%	70%	71%	72%	9%
	Max	P2.3	KLY_5CB1	30%	71%	73%	74%	9%
	Max	P2.3	WSN_2CB7	-	43%	34%	30%	-
	Max	P2.3	BLW_2CB4	44%	-	-	9%	3%

Note 1: The system conditions were adjusted as per System Operating Order 7T-13 Attachment 4.

Table B-2: Selected Bus Voltages for Study Scenarios

Case	IC's Plant Output	Contingency		Bus Voltage (PU)			
		Category	Description	WSN 230 (PU)	BLW 230 (PU)	RBF 230 (PU)	SCK 230 (PU)
31HW	Max	P0	N/A	1.0018	1.0292	1.0311	1.0391
32HS	Max	P0	N/A	1.0095	1.0323	1.0334	1.0475
	0 MW	P0	N/A	1.0123	1.0367	1.0382	1.053
32LS	Max	P0	N/A	1.0155	1.0274	1.0286	1.0394
	Max	P1.2	2L96_A	1.017	1.0334	1.0347	1.0444
	Max	P1.2	2L96_B	1.0101	1.0446	1.0451	1.0471

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 studies for 2031HW, 2031HS and 2032LS conditions is provided in the table below.

Table C-1: Transient Stability Study Results (31HW, 31HS, 32LS)

Category	Contingency	Fault Location	Fault Clearing Time (Cycles)		[redacted] Performance	Other Generators in the study area
			Close End	Far End		
P1.2	5L1	Close to WSN	4	4	Acceptable	Acceptable
P1.2	5L7	Close to WSN	4	4	Acceptable	Acceptable
P1.2	5L11	Close to WSN	4	4	Acceptable	Acceptable
P1.2	5L61	Close to WSN	4	4	Acceptable	Acceptable
P1.2	2L96.1 (WSN-NEC)	Close to WSN	6	7	Acceptable	Acceptable
P1.2	2L96.1 (WSN-NEC)	Close to NEC	6	7	Acceptable	Acceptable
P1.2	2L96.2 (NEC-BLW)	Close to NEC	6	7	Acceptable	Acceptable
P1.2	2L96.2 (NEC-BLW)	Close to BLW	6	7	Acceptable	Acceptable
P1.2	2L354	Close to BLW	6	7	Acceptable	Acceptable
P1.3	WSN_T2	WSN 500kV bus	6	6	Acceptable	Acceptable
P4	5L2_Stuck Breaker WSN_5CB3	Close to WSN	15	4	Acceptable	Acceptable
P4	2L96.1 (WSN-NEC) _Stuck Breaker WSN_2CB7	Close to WSN	15	7	Acceptable	Acceptable
P4	NEC Transmission Line _Stuck Breaker NEC CB	Close to NEC	15	7	Acceptable	Acceptable
P4	2L307_Stuck Breaker BLW_2CB2	Close to BLW	15	7	Acceptable	Acceptable
P4	2L354_Stuck Breaker BLW_2CB4	Close to BLW	15	7	Acceptable	Acceptable

Appendix D

IC Provided Power Flow and Dynamic Models and Data

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

- G1: [redacted]
- G2:
- G3:
- G4:

Table D-1 to Table D-5 shows dynamic model parameters provided by the IC for this SIS.

Table D-1: Renewable Energy Generator Mode Settings

[redacted]

Table D-2: Renewable Electrical Control Mode Settings

Unit	Model	Bus #	PFFLAG	VFLAG	QFLAG	PFLAG	PQFLAG	Vdip	Vup	Trv
[redacted]										

Table D-3: Renewable Plant Control Model Settings

Unit	Model	Bus #	Branch From Bus	Branch To Bus	Branch Circuit ID	VC	RefFlag	Fflag	Tfltr	Kp
[redacted]										

*Parameter setting requires further finetune prior to the project commissioning.

Table D-4: Under/Over Frequency Generator Trip Relay Settings

Unit	Model	Monitor Bus #	Generator Bus#	Generator ID	FL	FU	TP	TB		
[redacted]										

**

Unit	Generator Bus#	Generator ID
[redacted]		

Table D-5: Under/Over Voltage Generator Trip Relay Settings

Unit	Model	Monitor Bus #	Generator Bus#	Generator ID	VL	VU	TP	TB		
[redacted]										

**

Unit	Generator Bus#	Generator ID
[redacted]		

Appendix E

Preliminary One-Line Sketch for Future Proposed Switching Station (NETX)

The preliminary One-Line Sketch for the proposed switching station NETX is provided in Figure E-1.

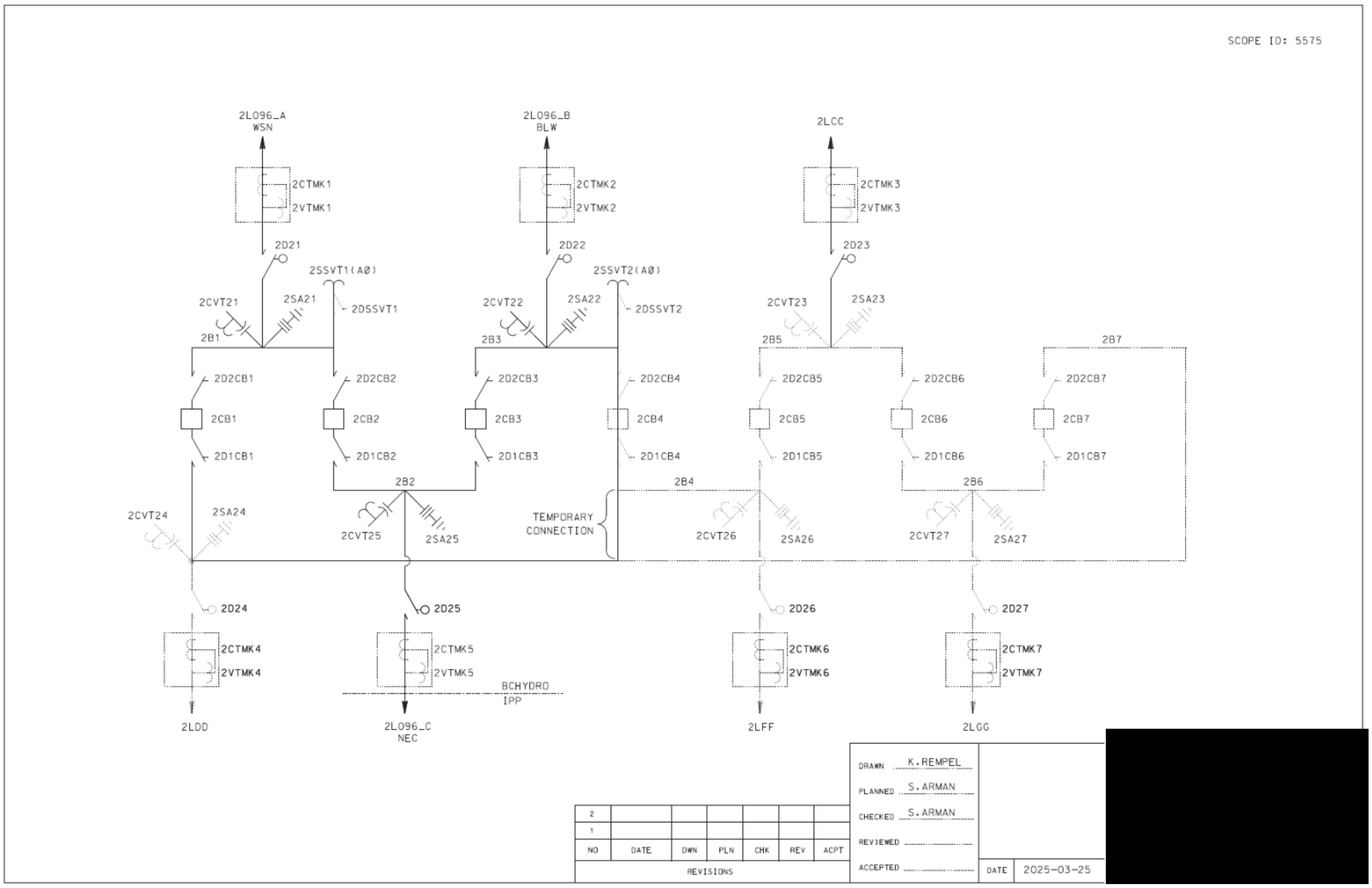

Figure E-1: Preliminary One-Line Sketch for the Proposed Switching Station NETX

Appendix F
Transmission Line Diagrams

The POI location, line 2L96, and the conceptual Ingress and Egress of proposed switching station NETX on 2L96 is provided in this appendix.

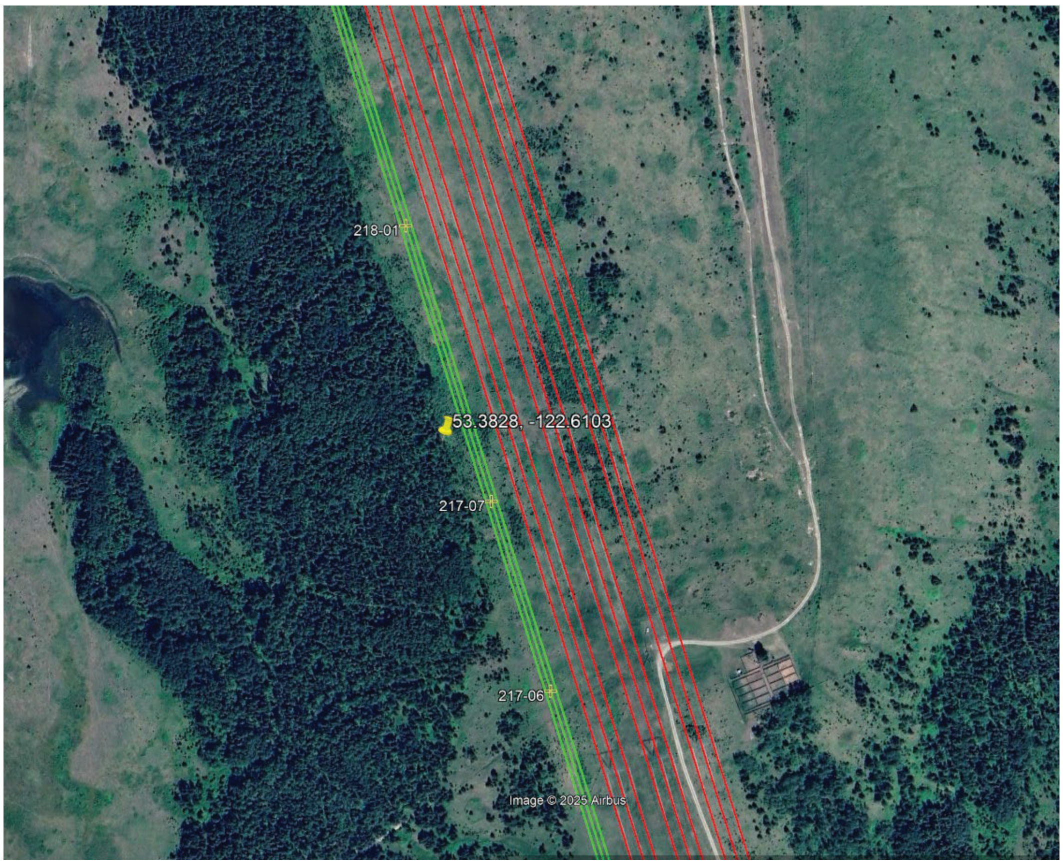

Figure F-1: POI Location Diagram

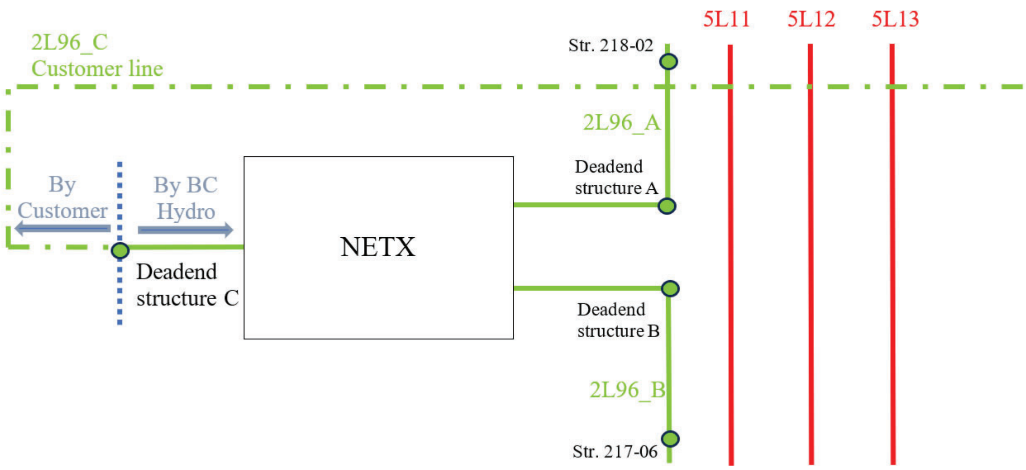

Figure F-2: Conceptual Ingress and Egress of Proposed Switching Station NETX on 2L96

Appendix G

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 WSN and NETX for “WSN-NETX 2L96_A PY/SY Digital Teleprot”.
- Provide WECC Level 3 64 kbps synchronous circuits between NETX and BLW for “NETX-BLW 2L96_B PY/SY Digital Teleprot”.
- Provide WECC Level 3 64 kbps synchronous circuits between NETX and NEC for “NETX-NEC 2L96_C PY/SY Digital Teleprot”.
- Provide WECC Level 1 transfer trip facilities from SBK to NETX for “GMS Area Gen Shed to NEC PY/SY”.
- Provide WECC Level 3 transfer trip facilities from SCK to NETX for “PY/SY SCK 2L95 OTL DTT”.
- Provide WECC Level 3 transfer trip facilities from RBF to NETX for “PY/SY RBF 2L95 OTL DTT”.
- Provide WECC Level 3 transfer trip facilities from RBF to NETX for “PY/SY RBF 2L354 OTL DTT”.
- Provide WECC Level 3 transfer trip facilities from BLW to NETX for “PY/SY BLW 2L354 OTL DTT”.

Telecontrol Requirements for Telecom

- Provide a NEC SCADA channel.
- Provide two IP based SCADA channels and a REMACC channel for NETX.

Other Requirements for Telecom

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

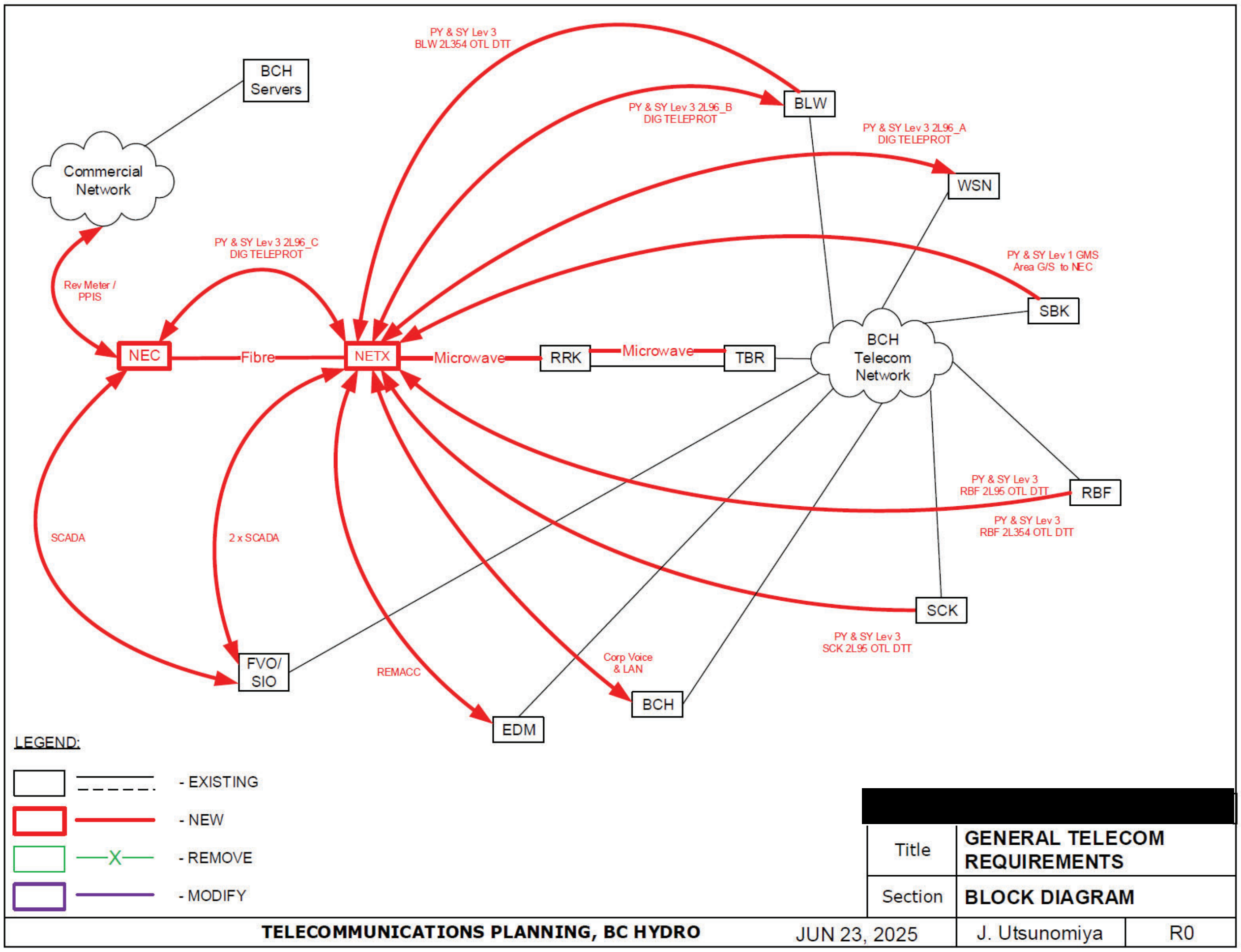

Figure G-1: The telecom block diagram identified for [redacted]

Appendix H
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.