BC Hydro
Power smart

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

November 24, 2025

[redacted]

via email: [redacted]

RE: CEAP IR #122 – [redacted] – Interconnection Feasibility Study

Dear [redacted]

Enclosed is the Interconnection Feasibility Study for the proposed Interconnection Request (IR), [redacted], submitted under Attachment M-2: Transmission Service and Interconnection Service Procedures for Competitive Electricity Acquisition Process (CEAP) 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 Feasibility 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.

Interconnection Study Costs

The Interconnection Customer is responsible for paying the full cost of all Interconnection Studies in cash. Interconnection Study costs vary depending on the scope, complexity, and other factors such as whether any scope is shared with another Interconnection Customer (not applicable to this Interconnection Feasibility Study). The deposit amounts specified in the OATT are not proxy Interconnection Study costs. If actual Interconnection Study costs exceed the deposit amount, the Interconnection Customer must pay the remaining balance in cash. Please refer to the answer for question no. 53 in the posted Questions & Answers for 2025 Call for Power for typical study cost ranges.

Cost Estimate

Based on the Interconnection Feasibility Study, the non-binding good faith estimated cost (typical accuracy range of +150%/-50%) for Network Upgrades required to interconnect your project is $7.5 M.

Major Scope of Work Identified:

- Supply and install required Protection, Control and Telecommunications equipment

Exclusions:

- GST
- Permits
- Right-of-Way & property costs
- The cost of new switching station on line 2L393 (third-party / customer owned)

Key Assumptions:

- Construction by contractor
- 3 months of construction is considered
- No construction during winter season
- Execution of early Engineering and Procurement Agreement
- Impact Benefit Agreements with First Nations are not considered

Key Risks:

- Major equipment delivery presents potential project cost and schedule risks, based on variance in equipment lead times
- No defined supply chain strategy; construction costs may increase depending on delivery method
- Project schedule may be longer than expected, leading to increased overhead costs
- Ground improvements may be required leading to increased construction costs
- Contaminated soil may be encountered leading to increased construction costs
- Cost of materials and major equipment may be affected by market conditions and escalation

Unique Project Consideration

The Interconnection Feasibility Study report has determined that a new switching station on line 2L393 is required to interconnect your IR to the BC Hydro transmission system. Because this switching station will be located between the Generating Facility and the Point of Change of Ownership, it falls under the Interconnection Customer's Interconnection Facilities (ICIF) scope. These facilities must be owned, designed and constructed by the Interconnection Customer.

Please note that the Network Upgrades scope, cost, and schedule provided in this Interconnection Feasibility Study do not include or account for the ICIF scope of work. If your IR proceeds to the Standard Generator Interconnection Procedures (SGIP), you will be required to provide a revised System Impact Study - Generator Interconnection Data Form and associated data, including details of the new switching station, for the System Impact Study.

Indirect Interconnection

Your IR involves an indirect interconnection to the BC Hydro Transmission System. Under the OATT Attachment M-1: Standard Generator Interconnection Procedures (SGIP) and the Standard Generator Interconnection Agreement (SGIA), the party executing the SGIA must be the owner of the Interconnection Customer Interconnection Facilities up to the POI. Depending on the scope of required Network Upgrades, this execution may occur years before the Commercial Operation Date.

Study Limitations and Exclusions

Protection, Control, and Telecommunications

The Interconnection Feasibility Study does not include a detailed review of the protection, control, and telecommunications system requirements specific to your Interconnection Request. Based on a high-level review, we have identified proxy costs for protection, control, and telecom Network Upgrades drawn from comparable interconnection projects with similar scope and complexity; these proxy costs have been included solely for indicative budgeting purposes. The relative interconnection cost determined by the Interconnection Feasibility Study includes a telecommunications component based on an assumed solution to deliver teleprotection and telecontrol circuit requirements necessary for the Interconnection Request. Protection, control, and telecommunications system requirements will be reviewed in detail in the System Impact Study if you are a successful participant of the CEAP and meet applicable requirements.

For Interconnection Feasibility Study purposes, it is assumed that any applicant-proposed works that could obstruct or impair the performance of existing BC Hydro microwave systems or new links from the proposed Interconnection Customer Interconnection Facilities (ICIF) to the BC Hydro microwave system would be identified and either relocated or repositioned as determined in a System Impact Study if you are a successful participant of the CEAP and meet applicable requirements. Such works may include, but are not limited to, towers, turbines, dams, support structures, panels, surface materials deposited or redistributed, water surface changes, or vegetation.

Generation Shedding/Curtailment Scheme and Electromagnetic Transient (EMT) Studies

The generation shedding/curtailment scheme reviews (e.g., Remedial Action Scheme (RAS), and a direct transfer trip for anti-islanding scheme) and EMT studies are completed in a System Impact Study. The outcomes of these studies may result in additional requirements, which could include Network Upgrades or ICIF. Any costs associated with completion of these studies, and resulting requirements, are not included in the Interconnection Feasibility Study cost estimate.

Revenue Metering

Please note that revenue metering requirements have not been determined with the Interconnection Feasibility Study. As such, any costs associated with revenue metering and other interconnection components are not included in the cost estimate provided above. Once these requirements are defined, 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 Feasibility Study, the non-binding good faith estimated in-service date for your Interconnection Request's Network Upgrades is Quarter 4 2030 (calendar year). To achieve this timeline, we may need to expedite certain activities, including engineering design and procurement of long-lead equipment.

Timely actions required from you to minimize risks to the schedule:

- Submission of additional technical data required for the System Impact Study and Facilities Study
- Submission of any required information or document such as demonstration of Site Control
- Execution of Combined Study Agreement and Standard Generator Interconnection Agreement
- Financial commitments and securities

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

If you have any questions, please contact the BC Hydro CEAP team at ceap2025@bchydro.com.

Sincerely,

[redacted]

[redacted]

Manager, Customer Interconnections

BC Hydro

Encl.: CEAP_2025_IR122_[redacted]_Feasibility_Study.pdf

[redacted]

Interconnection Feasibility Study

BC Hydro EGBC Permit to Practice No: 1002449

2025 CEAP IR #122

Prepared for: [redacted]

Prepared by: [redacted]

Sr. Engineer, Transmission Operations Services

Reviewed by: [redacted]

Principal Engineer, Transmission Operations Services

Accepted by: [redacted]

Manager, Transmission Planning

Report Metadata

Header:	2025 CEAP IR #122
Subheader:	Interconnection Feasibility Study
Title:	[redacted]
Subtitle:	2025 CEAP IR #122
Report Number:	1000-APR-00068
Revision:	0
Confidentiality:	Public
Date:	2025 Nov 21
Volume:	1 of 1
Prepared for:	[redacted]
Prepared by:	[redacted]
Title:	Sr. Engineer, Transmission Operations Services
Checked by:	[redacted]
Title:	Specialist Engineer, Transmission Operations Services
Reviewed by:	[redacted]
Title:	Principal Engineer, Transmission Operations Services
Related Facilities:	2L393
Additional Metadata:	Transmission Planning 2025-128 Filing Subcode 1350

Revisions

Revision	Date	Description
0	2025 Nov	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 accept responsibility for the content in the specified sections. Professionals apply their signature and/or seal as appropriate.

Section:	**Discipline:**
Entire report except listed below	Transmission Planning
Contributed by:	[redacted] [redacted] Sr. Engineer, Transmission Operations Services

Section:	**Discipline:**
5.2, 5.3	Stations Planning
Contributed by:	[redacted] [redacted] Specialist Engineer, Station Planning

Executive Summary

[redacted], the Interconnection Customer (IC), requests to interconnect its [redacted] (2025 CEAP IR #122) to the BC Hydro (BCH) system. [redacted] has ten (10) [redacted] type-4 wind turbine generators (WTG) with total installed capacity of 70 MW. The IC's proposed Point of Interconnection (POI) is on BCH's substation Sukunka (SNK) via the third-party owned 230 kV line 2L393. The IC's project will connect to 1L393 via a 2 km 230 kV interconnection line. The proposed commercial operation date (COD) is Dec 31, 2030.

To interconnect the [redacted] and its facilities to the BCH Transmission System at the proposed POI, this Feasibility Study has made the recommendations and conclusions as follow:

1. A new 230 kV switching station (referred to as "P122T") on 2L393 is required for interconnecting the IC's generating project to the BCH system. The new switching station will be designed, built and owned by the IC.

2. The connection of [redacted]oject does not cause any performance violation (i.e., thermal overload, voltage performance violation or voltage stability concern) under system normal conditions.

3. For critical single contingencies (N-1 conditions), the study has observed thermal overloads on 2L308, 2L312, and 2L309. The [redacted] is required to participate in the existing generation shedding remedial action scheme (RAS) to secure the system. Detailed RAS functional requirement modifications will be specified later if the IC's project proceeds to next stage of the interconnection process.

4. [redacted] is not arranged for islanded operation. In addition, the IC is required to install anti-islanding protection within its facility to disconnect the IC's generating plant from the grid when an inadvertent island with the local load forms. The anti-islanding protection shall be configured in the manner that does not compromise the required ride-through performance.

5. The [redacted] is required to have the dynamic reactive power capability at a minimum of +/- 33% of its MPO at the high

voltage side of the IC's switchyard over the full MW operating range, per BCH's TIR Section 6.4.2.

6. The "STATCOM option" for the proposed type-4 WTGs is required so that each turbine can provide reactive power capability at zero MW output including during turbine standstill.

7. Fast Frequency Response, also known as Inertia Control in the proposed wind turbines, is required at the [redacted]. The proposed WTGs, when equipped with the Inertia Control option, are expected to temporarily boost the MW output to limit the system frequency drop during a major frequency event. The Inertia Control settings should be determined in coordination with BCH in the later stage of the interconnection process.

The above conclusions are made based on the IC's input data and study assumptions listed in Section 4, which represent the best available information on October 14, 2025.

A non-binding good faith cost for required network upgrades and estimated schedule for construction are included in a separate letter to the IC.

Please note that, this Feasibility Study report does not include the descriptions of Protection, Control, and Telecommunications requirements and the associated upgrade scopes; however, as discussed in Section 2 "Purpose and Scopes of Study", the associated cost implications are captured and delivered in the cover letter to the IC.

Contents

Appendices

Acronyms

The following are acronyms used in this report.

BCH	BC Hydro
CEAP	Competitive Electricity Acquisition Process
COD	Commercial Operation Date
DTT	Direct Transfer Trip
ERIS	Energy Resource Interconnection Service
IBR	Inverter-Based Resources
IC	Interconnection Customer
IR	Interconnection Request
IPP	Independent Power Producer
LAPS	Local Area Protection Schemes
MPO	Maximum Power Output
NERC	North American Electric Reliability Corporation
NRIS	Network Resource Interconnection Service
OATT	Open Access Transmission Tariff
POI	Point of Interconnection
RAS	Remedial Action Scheme
TIR	BC Hydro “60 KV to 500 kV Technical Interconnection Requirements for Power Generators”
WECC	Western Electricity Coordinating Council
WTG	Wind Turbine Generator

1 Introduction

Table 1-1 below summarizes the project reviewed in this Feasibility Study.

Table 1-1 Summary of Project Information

Project Name	[redacted]	
Name of Interconnection Customer (IC)	[redacted]	
Point of Interconnection (POI)	SNK 230 kV via 2L393	
IC's Proposed COD	December 31, 2030	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	68.6 MW (Summer)	68.6 MW (Winter)
Number of Turbines	10 x 7.0 MW WTGs	
Plant Fuel	Wind	

[redacted], the interconnection customer (IC), requests to interconnect its [redacted] (2025 CEAP IR #122) to the BC Hydro (BCH) system. [redacted] has ten (10) [redacted] type-4 wind turbine generators (WTG) with total installed capacity of 70 MW. The IC's proposed Point of Interconnection (POI) is on BCH's substation Sukunka (SNK) via the third-party owned 230 kV line 2L393. The IC's project will connect to 2L393 via a 2 km 230 kV interconnection line. The proposed commercial operation date (COD) is Dec 31, 2030.

Figure 1-1 shows the Peace Region transmission system diagram. Sukunka substation (SNC) is a major substation in this area that interconnects three 230 kV transmission lines 2L313 from Meikle Terminal Station (MKT), 2L309 from Dokie Terminal Station (DKT), and 2L312 from Sundance Lakes Substation (SLS). These lines enable the integration of Independent Power Producer (IPP) wind farm generation and transmission-voltage customer loads in the Tumbler Ridge area with BCH's integrated system, through connections to the G.M. Shrum Generating Station (GMS) and the South Bank Substation (SBK).

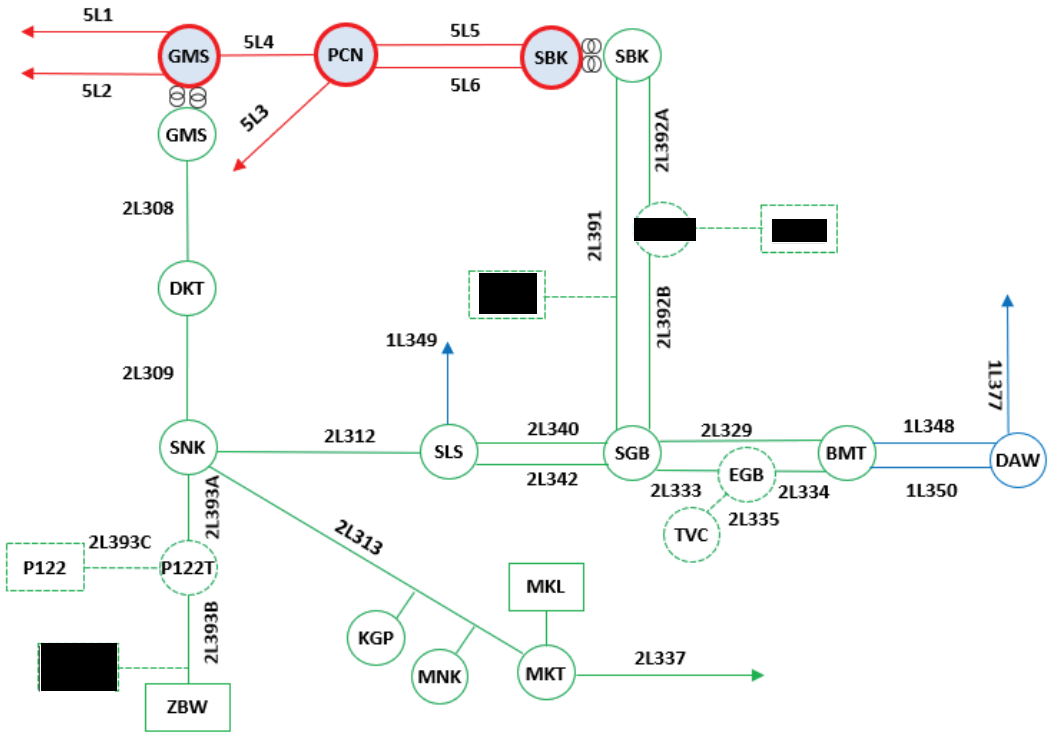

Figure 1-1: Peace Region Transmission System Diagram

The existing line 2L393 is a customer owned radial circuit to ZBW which is an existing wind farm with the capacity of 32 MW. Another planned wind farm, [redacted] with capacity of 56 MW, will tap into the same line. The COD of [redacted] is September 30, 2030.

In addition to ZBW, there are multiple other IPPs in the study region.

- Quality Wind Farm (QTY) has a total capacity of 142.2 MW and is connected to TLR via 2L315.
- Moose Lake Wind Farm (MLW) has a total capacity of 15 MW and is tap connected on the line 2L337.
- Meikle Wind Farm (MKL) has a total capacity of 184.6 MW and is connected to MKT via 2L339.
- Dokie Wind Farm (DKW) has a total capacity of 144 MW and is connected to DKT via 2L314.
- Bear Mountain Wind Farm (BMW) has a total capacity of 105.4 MW and is connected to BMT via 1L354.

In addition, the Peace Region has two future proposed generating projects with higher queue priority — [redacted] and [redacted] with installed capacity of 200 MW each. These are the [redacted]

2 Purpose and Scopes of Study

This Feasibility Study is a preliminary evaluation of the system impact of interconnecting the proposed project to the BCH system based on power flow and short circuit analysis in accordance with BCH's Open Access Transmission Tariff (OATT) and produces the estimated cost of required Network Upgrades and the implementation schedule.

Per OATT, the Feasibility Study is performed individually for each of the participating projects in the CEAP process and focuses specifically on the BCH regional transmission system where the proposed generating project is connected and affects.

This is a "limited scope" study which is restricted to power flow studies of P0, P1 and P2 planning events as defined in TPL-001-4 and short circuit analysis. The study does not address other technical aspects such as transient stability and switching transients and impact of multiple contingencies. These subjects will be addressed in subsequent System Impact Study (SIS) if the project proceeds further. In addition, any potential impacts to the adjacent external systems to BCH would be addressed in subsequent detailed and coordinated studies with the relevant adjacent entities if the proposed generator project proceeds further.

Please note that, due to the compressed study timeline for CEAP 2025 Feasibility Studies, this report does not include the descriptions of the Protection, Control, and Telecommunication requirements and the associated upgrade scopes. Instead, the network upgrades associated with Protections, Controls and Telecommunications are incorporated with cost estimates in a separate cover letter to the IC.

.

3 Standard and Criteria

The Feasibility Study is performed in compliance with the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards, and the BCH interconnection requirements in the TIR, and upon the ratings of the existing BCH transmission facilities described in Operating Orders, specifically:

- NERC standards: TPL-001-4 and FAC-002-3 relevant to the scope of this Feasibility Study.
- WECC criteria TPL-001-WECC-CRT-4 Transmission System Planning Performance, July 1, 2023.
- BC Hydro's 60 kV to 500 kV Technical Interconnection Requirements for Power Generators, Rev 2.1.1, Effective: Sept 22, 2025.
- BC Hydro Operating Order 5T-10, Ratings for All Transmission Circuits 60 kV or Higher, Sept 17, 2025.
- BC Hydro Operating Order 5T-14, Ratings for All Transmission and Distribution Transformer, Sept 22, 2025.
- BC Hydro System Operating Order 7T-22 System Voltage Control, Sept 19, 2023.

4 Assumptions and Conditions

This Feasibility Study is performed based on the IC's submitted data and information available to BCH on October 14, 2025 for the study purpose. Assumptions are made wherever the IC's input is unavailable. Appendix A shows the schematic diagram of the IC's Project IC's project used in the study model.

The power flow study cases used in this Feasibility Study are established based upon the BCH base resource plan and load forecasts available at the time of performing the study, which includes existing and future generators, transmission facilities, and loads in addition to the subject interconnection project in this study. Applicable seasonal conditions and the appropriate study years for the study planning horizon are also incorporated. Additional assumptions are listed as follows.

1) The generation in the study area are dispatched to the patterns that stress the transmission system in the study area. In these patterns, the associated generators are typically set to their Maximum Power Outputs (MPO) unless otherwise specified.

2) A new 230 kV/138 kV transformer at BMT (i.e., BMT T4) is planned to be installed in June 2026 to accommodate load addition.

3) The [redacted] is included in all study scenarios since it's a successful project selected in the 2024 Call for Power. SKD will add 199.9 MW of generating capacity to the region.

4) The [redacted] is included in all study scenarios since it's a successful project selected in the 2024 Call for Power. TAW will add 200 MW of generating capacity to the region.

5) The [redacted] is included in all study scenarios since it's a [redacted] project [redacted] will add 56 MW of generating capacity to the region.

5 System Studies and Results

Based upon the IC's submitted information and the area system conditions, a new customer built switching station (temporarily referred to as "P122T") on 2L393 is required to interconnect the IC's generating project to the BCH system. There are multiple terminals and multiple sources on the existing line 2L393. The addition of the new switching station is required to maintain reliability and adequate protection performance to accommodate the new interconnection and serve the existing customers.

With the new switching station P122T, the existing line 2L393 will be segregated into two new circuits, referred to as: 2L393_A (SNK-P122T) and 2L393_B (P122T-ZBW). The interconnection line, to be built by the IC, is temporarily referred to as 2L393_C (P122-P122T). These temporary line designations will be replaced by permanent ones at a later stage of interconnection study.

5.1 Power Flow Study Results

Power flow studies were performed to evaluate whether the IC's generating project would cause any unacceptable system performance (e.g. equipment overloads, steady-state voltage violation and voltage instability) and to determine the system reinforcement requirement based on steady state performance analysis.

The study focuses on the base scenario — 30HW/31LS/31HS system conditions that include all the higher-queued generating projects ([redacted]) in the region and the future proposed WBK-REC tie line. These base cases were prepared based on factors such as load conditions, seasonal variation in ambient temperatures, and generation patterns that stress the transmission system.

The studies are performed for system normal conditions and under critical system contingencies specified in the P1 and P2 events by NERC TPL-001-4. Study results are summarized below.

5.1.1 Thermal Overload Analysis

Table 5-1 summarizes the thermal overload concerns identified in the study and the proposed solutions. Appendix B contains the details of thermal overload analysis results.

Table 5-1: Thermal Overload Concerns and Proposed Solutions

Equipment subject to overloads	Conditions observed	Contingencies that result in overloads	Solution Proposed
Under contingencies			
2L308	LS, HS, HW	P1.2: 2L312 P2.3: SLS 2CB14 fault	[redacted] participate in the Peace Region generator shedding RAS.
2L312	LS, HS, HW	P1.2: 2L308, 2L309	[redacted] participate in the Peace Region generator shedding RAS.
2L309	LS, HS	P1.2: 2L312	[redacted] participate in the Peace Region generator shedding RAS.

The study shows that the addition of [redacted] Project would not cause any thermal overloads under system normal condition.

For N-1 contingency conditions, the study observed several pre-existing overloads on 2L308 and 2L312 under single contingencies (i.e., 2L308, 2L309, 2L312, and SLS 2CB14). The connection of [redacted] Project will aggravate these pre-existing overloads, which is currently addressed by Peace Region generator shedding RAS. In 31LS and 31HS scenarios, [redacted] Project causes new overload on 2L309 under single contingencies (i.e. 2L312) but the bottleneck is still the 2L308. [redacted] Project must participate in the existing Peace Region generator shedding RAS.

In addition, the generators at this IC are also required to participate in GMS Area Gen Shed RAS scheme for Peace 500 kV transmission line contingencies.

Detailed Peace Region Local Gen Shed RAS and GMS Area Gen Shed RAS functional requirement modifications will be specified later if the IC's project proceeds to next stage of the interconnection process.

5.1.2 Steady-State Voltage Analysis

With the connection of the IC's project, the stead-state voltage performance under system normal and single contingency conditions is acceptable for all the three load conditions (31LS, 31HS, 30HW). Appendix B shows the details in the steady-state voltage study results.

5.1.3 Reactive Power Capability Evaluation

The BCH TIR requires IBR power plant to have the dynamic reactive power capability at a minimum of +/- 33% of its MPO at the high voltage side of the IC's switchyard over the full MW operating range.

Based on the power flow model data submitted by the IC, the proposed [redacted] Project would be capable of meeting the BCH reactive capability requirement at the plant's maximum MW output, which is subjected to further verification in the next stage of the interconnection process.

In addition, according to the IC-provided reactive capability data, the proposed WTG would provide +4.4 Mvar to -4.4 Mvar reactive capability at the zero MW output if the turbine's "STATCOM" function is enabled. This function needs to be re-confirmed if the IC's project proceeds to next stage of the interconnection process.

5.1.4 Anti-Islanding Requirements

[redacted] Project is not arranged for islanded operation. In addition, the IC is required to install anti-islanding protection within its facility to disconnect the IC's wind farm from the grid when an inadvertent island with the local loads forms.

5.1.5 Other Performance Requirements

Fast Frequency Response, also known as Inertia Control in the proposed wind turbines, is required at the [redacted] Project. The proposed WTGs, when equipped with the Inertia Control option, are expected to temporarily boost the MW output to limit the system frequency drop during a major frequency event. The Inertia Control settings should be determined in coordination with BC Hydro in the later stage of the interconnection process.

5.2 Fault Analysis

The short circuit analysis in the Feasibility Study is based upon the latest BC Hydro system model, which includes the generating facility information and associated impedance data provided by the IC. A more detailed study will be performed at the System Impact Study stage if needed.

5.3 Stations Requirements

The Point of Interconnection (POI) is on BC Hydro's substation Sukunka (SNK) via 230 kV line 2L393. A new 230 kV switching station (referred to as "P122T") on 2L393 is required for interconnecting the IC's generating project to the BCH system. The new switching station will be designed, built and owned by the IC.

No station work is required for this interconnection project.

6 Cost Estimate and Schedule

The non-binding good faith estimated cost and time to construct the Network Upgrades required to interconnect the proposed project will be provided in a separate letter to the IC.

7 Conclusions

To interconnect the [redacted] Project and its facilities to the BCH Transmission System at the POI, this Feasibility Study has identified the following conclusions and requirements:

1. A new 230 kV switching station (referred to as “P122T”) on 2L393 is required at the proposed POI for interconnecting the IC’s generating project to the BCH system. The new switching station will be owned and designed by the IC. The key factor for making this decision is that the [redacted] project has already approved as a tap connection on line 2L393.

2. The connection of [redacted] Project does not cause any performance violation (i.e. thermal overload, voltage performance violation or voltage stability concern) under system normal conditions.

3. For N-1 conditions, the study has observed thermal overloads on 2L308, 2L312, and 2L309. The [redacted] Project may need to participate in the generation runback or shedding Remedial Action Scheme (RAS) to secure the system. The RAS function scope will be specified in the System Impact Study (SIS) if the need for RAS is determined.

4. [redacted] Project is required to install anti-islanding protection within its facility to disconnect the IC’s generating plant from the grid when an inadvertent island with the local load forms. The anti-islanding protection shall be configured in the manner that does not compromise the required ride-through performance.

5. The [redacted] Project is required to have the dynamic reactive power capability at a minimum of +/- 33% of its MPO at the high voltage side of the IC’s switchyard over the full MW operating range, per BC Hydro’s TIR Section 6.4.2.

6. The “STATCOM option” for the proposed type-4 WTGs is required so that each turbine can provide reactive power capability at zero MW output including during turbine standstill.

7. Fast Frequency Response, also known as Inertia Control in the proposed wind turbines is required at the [redacted] Project. The proposed WTGs, when equipped with the Inertia Control option, are

expected to temporarily boost the MW output to limit the system frequency drop during a major frequency event. The Inertia Control settings should be determined in coordination with BC Hydro in the later stage of the interconnection process.

Appendix A
Schematic Diagram of the IC's Project

Figure A-1 shows the schematic diagram for the [redacted] Project.

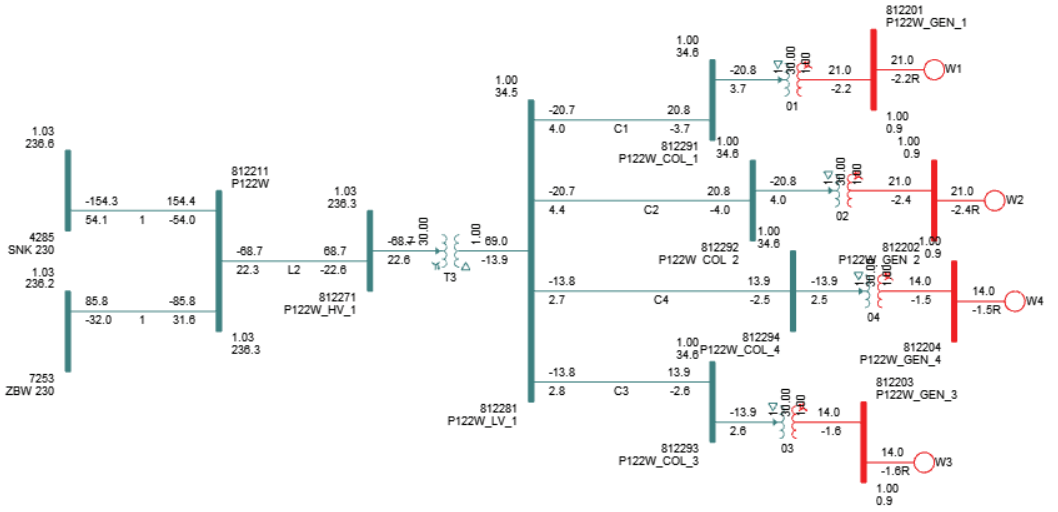

Figure A-1: [redacted] Project Plant Schematic Diagram.

Appendix B
Power Flow Study Results

Base Scenario (30HW/31HS/31LS)

Table B-1: Thermal Overload Study Results

Case	North Coast Regional Generation	Contingency		Branch Loading (% of its seasonal normal rating)		
				2L308	2L312	2L309
		Cat.	Description	DKT-GMS	SNK-SLS	SNK-DKT
Winter Rating in MVA				541.4	538.2	539.4
30HW	Max	P1.2	2L312 OOS	106.8 %	-	82.1 %
	Max	P1.2	2L308 OOS	-	106.8 %	25.5 %
	Max	P2.3	SLS 2CB14 fault	86.6 %	19.9 %	61.9 %
Summer Rating in MVA				427.5	424.7	427.5
31HS	Max	P1.2	2L312 OOS	138.8 %	-	107.2 %
	Max	P1.2	2L308 OOS	-	138.8 %	32.1 %
	Max	P1.2	2L309 OOS	32.6 %	106.7 %	-
	Max	P2.3	SLS 2CB14 fault	113.7 %	24.7 %	82.2 %
Summer Rating in MVA				427.5	424.7	427.5
31LS	Max	P1.2	2L312 OOS	138.6 %	-	107.1 %
	Max	P1.2	2L308 OOS	-	138.8 %	32.1 %
	Max	P1.2	2L309 OOS	32.4 %	106.6 %	-
	Max	P2.3	SLS 2CB14 fault	113.9 %	24.5 %	82.4 %
Note: SLS 2CB14 internal fault result in loss of 2L340 and 2L342.						

Table B-2: Steady-State Voltage Study Results

Case	IC's Plant Output	Contingency		Bus Voltage (PU)		
		Cat.	Description	SNK 230	DKT 230	SLS 230
30HW	Max	P0	System Normal	1.029	1.026	1.032
31HS	Max	P0	System Normal	1.028	1.025	1.033
31LS	Max	P0	System Normal	1.029	1.023	1.035
	Max	P1.2	2L312 OOS	1.009	0.994	1.036
	Max	P1.2	2L308 OOS	1.022	1.026	1.024