BC Hydro
Power smart

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

November 24, 2025

[redacted]

via email: [redacted]

RE: CEAP IR #44 – [redacted] – Interconnection Feasibility Study

Dear [redacted]

Enclosed is the Interconnection Feasibility Study for the proposed Interconnection Request (IR), [redacted] [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 $524.1 M.

Major Scope of Work Identified:

- Thermally upgrade the overhead circuit 1L384 with Mica ACSR conductor between the POI and Glenannan substation (GLN)

- Upgrade overhead circuits to install telecom fibre:
    - 1L384B from POI to Palling capacitor station (PLG)
    - 1L396 from Houston substation (HUS) to Telkwa substation (TKW)
    - 1L384A Burns Lake substation (BRN) to new switching substation
- Acquire property near line 1L384 and construct a new 138 kV, 3-circuit breaker ring bus switching substation
- Construct a new control building and other required substation facilities and infrastructures
- Cut the existing 1L384 and loop into the new station
- Terminate the customer's 138 kV line at the new station
- Supply and install required Protection, Control and Telecommunications equipment at all required locations

Exclusions:

- GST
- Permits
- Right-of-Way & property costs

Key Assumptions:

- Construction by contractor
- 36 months of construction is considered
- No construction during winter season
- Execution of early Engineering and Procurement Agreement
- Ability to acquire adequate property for a new switching station close to the existing transmission line 1L384
- Ability to acquire sufficient Right-Of-Way for thermal upgrades to 1L384
- No expansion of existing stations or control buildings to accommodate new equipment
- A certificate of public convenience and necessity (CPCN) requirement will be exempt
- Impact Benefit Agreements with First Nations are not considered
- Full line replacement including reconductoring and structure replacements (58km) are assumed
- Original 138kV line to be demolished and removed

Key Risks:

- Cost and ability of obtaining new property for the new switching station may be higher than estimated which may increase the Network Upgrade cost estimate and schedule.
- Expansion of the existing control building may be required leading to increased costs and/or a longer project schedule
- 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
- If a CPCN is required for the project, it may impact project cost and schedule risks

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 3 2033 (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

Since your proposed POI is located within the North Coast Transmission Line Region, the interconnection of your IR has been determined, at this time, to be dependent upon the completion of the North Coast Transmission Line (NCTL) project.

Accordingly, please note the 2025 Call for Power Addendum 5 and revised Specimen EPA specify that the Guaranteed Commercial Operation Date for a project which is dependent upon the completion of NCTL will be October 1, 2033, notwithstanding that the Interconnection Feasibility Study report may indicate an earlier date.

Please note that changes to your IR or delays in data submission or financial commitments may also impact the target in-service date. 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_IR44_[redacted]_Feasibility_Study.pdf

[redacted]

2025 CEAP IR # 44
Interconnection Feasibility Study

BC Hydro EGBC Permit to Practice No: 1002449

2025 CEAP IR # 44

Prepared for: [redacted]

Prepared by: [redacted]

[redacted]

[redacted]

Specialist Engineer, Transmission Operations Services

Reviewed by: [redacted]

[redacted]

Principal Engineer, Transmission Operations Services

Accepted by: [redacted]

[redacted]

Manager, Transmission Planning

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Prepared for:	[redacted]
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Revision	Date	Description
0	2025 Nov	Initial release

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Sr. Engineer, Transmission Lines Engineering

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Executive Summary

[redacted], the interconnection customer (IC), requests to interconnect its [redacted] (2025 CEAP IR # 44) to the BC Hydro system. [redacted] has thirty-four (34) [redacted] type-3 wind turbine generators, adding a total capacity of 200.6 MW with a maximum power injection of 182.9 MW into the BC Hydro system at the Point of Interconnection (POI). The POI is on BC Hydro's 138 kV line 1L384, approximately 45 km from Topley substation (TPY). The IC's proposed commercial operation date (COD) is Oct 31st, 2032.

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 138 kV switching station (referred to as "P44T") on 1L384 is required at the proposed POI for interconnecting the IC's generating project to the BCH system. With the new switching station P44T, the existing line 1L384 will be segregated into two new circuits, temporarily referred to as: 1L384_A (GLN-P44T) and 1L384_B (P44T-TPY). The interconnection line, to be built by the IC, is temporarily referred to as 1L384_C (P44-P44T). These temporary line designations will be replaced by permanent ones at a later stage of interconnection study.

2. The study identified new thermal overload on 1L384_A line sections from POI to Glenannan substation (GLN) under system normal condition in heavy summer, light summer, and heavy winter loading scenarios. These line sections require higher ampacity of 860 amperes or greater at 35°C ambient temperature to accommodate [redacted] interconnection.

3. Rebuild of 1L384_A line sections from the POI to GLN with "Mica" ACSR conductor is required to meet the rating requirement. Additional Right of Way (ROW) may also be needed. In addition, fiber optic cables are required to be installed to meet protection, control, and telecommunication requirement from the POI to Palling capacitor station (PLG) along 1L384_B line structures, Houston substation (HUS) to Telkwa (TKW) substation

along 1L396 line structures, from Burns Lake substation (BRN) to P44T along 1L384_A line structures.

4. GLN T5 is overloaded under single contingency (GLN T1, GLN T11, GLN 2CB2, GLN 1CB6). Likewise, GLN T11 is overloaded under single Contingency (GLN T2, GLN T5, GLN 2CB8, GLN 1CB7). The overload could be mitigated by a Remedial Action Scheme (RAS) which will shed or run back the IC's project in response to the contingencies. The exact RAS requirements will be determined in subsequent studies if the project proceeds.
5. 1L384_B, 1L396, 1L398, TKW T4 and T5 are overloaded when 1L384_A is scheduled out of service and Houston substation (HUS) 1D26 is closed to connect HUS and TPY. IC's generating plant needs to be limited to the appropriate level before closing 1D26. Further operational restrictions or RAS may be required for another regional contingency under this operating condition. The exact requirement will be determined in subsequent studies if the project proceeds.
6. In addition, [redacted] will be required to be integrated in the existing BC Hydro RAS to maintain system reliability for 500 kV contingencies. The exact RAS requirements will be determined in subsequent studies if the project proceeds.
7. [redacted] 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.
8. [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 BC Hydro's TIR Section 6.4.2.
9. The "STATCOM option" for [redacted] type-3 WTGs is required so that each turbine can provide reactive power capability at zero MW output. BC Hydro recognizes that Type-3 WTGs with the STATCOM option have an inherent limitation—providing only partial reactive power capability during turbine standstill.

10. Fast Frequency Response, also known as Virtual Inertia Control (VIC) in [redacted] wind turbines is required at the [redacted] [redacted]. 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 the call 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
FeS	Feasibility Study
IBR	Inverter-Based Resources
IC	Interconnection Customer
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)	on 1L384 at 45 km from TPY	
IC's Proposed COD	31st October 2032	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	182.9 MW (Summer)	182.9 MW (Winter)
Number of Turbines	34 x 5.9 MW WTGs	
Plant Fuel	Wind	

[redacted]., the interconnection customer (IC), requests to interconnect its [redacted] (2025 CEAP IR # 44) to the BC Hydro system. [redacted] has thirty-four (34) [redacted] type-3 wind turbine generators, adding a total capacity of 200.6 MW with a maximum power injection of 182.9 MW into the BC Hydro system at the Point of Interconnection (POI). The POI is on BC Hydro's 138 kV line 1L384, approximately 45 km from Topley substation (TPY). The IC's proposed commercial operation date (COD) is Oct 31st, 2032.

Figure 1-1 shows the Glenannan region transmission system diagram. Glenannan substation (GLN) is a major substation in this area connecting to Williston substation (WSN) via 500 kV line 5L61, and Telkwa substation (TKW) via 500 kV line 5L62. GLN has two existing 500/230 kV transformers (GLN T1 & T2), two 230/138 kV transformers (GLN T5 & T11), and three 138/69 kV transformers (GLN T3, T4 & T6). GLN presently supplies two 230 kV transmission lines — 2L353 to the Tachick substation (TAC), 2L355 to Blackwater Mine substation (BWM); one 138 kV lines — 1L384 to Burns Lake substation (BRN); two 69 kV lines — 60L341 to Fraser Lake substation (FSR) and 60L352 to Endako [redacted] owned by [redacted] (EKO).

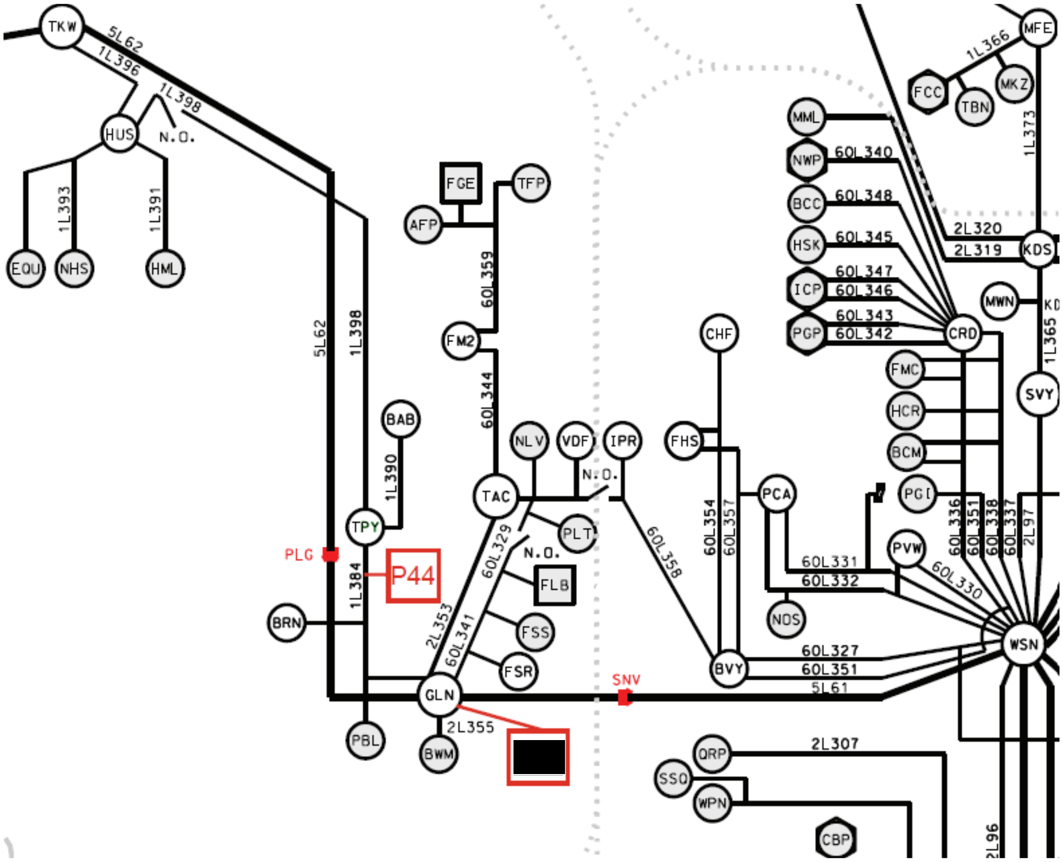

Figure 1-1: Glenannan region Transmission System Diagram

The existing line 1L384 is a radial circuit from GLN that mainly supplies Pinnacle Burns Lake substation (PBL), Burns Lake substation (BRN), and Topley substation (TPY). PBL and BRN are two existing facilities tap-connected on the line and PBL is a customer owned substation by [redacted].

1L398 between Houston substation (HUS) and Topley substation (TPY) is normally open ended at HUS with 1D26 open to avoid 138 kV tie between Glenannan substation (GLN) and Telkwa substation (TKW) and excessive power flow upon loss of 500 kV lines. For certain line section outages of 1L384, HUS 1D26 can be closed to supply TPY, Babine Lake substation (BAB), or BRN.

There are two existing customers' owned power plants in the study region.

- Fort St. James Green Energy Generating Station (FGE) has a total capacity of 40 MW and is connected to TAC substation via the line 60L344.

- Fraser Lake Biomass Generating Station (FLB) has a total capacity of 7.2 MW and is connected to GLN substation via 60L329.

In addition to the existing generators, the North Coast region has three (3) future proposed generating projects with higher queue priority: [redacted] project and [redacted] project with installed capacity of 15 MW and 266.7 MW respectively, and [redacted] project with installed capacity of 205.2 MW. Together, these three projects represent nearly 486.9 MW of generating capacity addition to the North Coast region.

2 Purpose and Scopes of Study

This Feasibility Study is a preliminary evaluation of the system impact of interconnecting the proposed project to the BC Hydro 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 BC Hydro 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 if the project proceeds further. In addition, any potential impacts to the adjacent external systems to BC Hydro 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 Study, 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 BC Hydro on Oct 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 BC Hydro's 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) BC Hydro Prince George Capacitor Bank Project (PGTC) project, Prince George to Glenannan Transmission Project (PGGT), and Glenannan to Terrace Transmission Project (GTTT) are included in the study. PGTC project will add series compensation for 5L61, 5L62, and 5L63, and a new 500KV/230KV transformer SKA T3. PGGT Project will construct 500 kV line - 5L64 from Williston to Glenannan substation. GTTT project will construct two 500 kV lines - 5L65 and 5L66 from Glenannan to Skeena substation. Based on the schedule available at the time of study, the PGTC project will be completed by October 2027, PGGT project will be completed by October 2030, and GTTT project will be completed by May 2032.

3) Two high-queued generation interconnection projects in the North Coast including [redacted] project and [redacted] project with installed capacity of 15 MW and 266.7 MW are going to be connected near Skeena and Telkwa area. These projects are included in the study. The commercial operation dates are January 2028 and August 2030 respectively.

4) [redacted] project, [redacted], with installed capacity of 205.2 MW will also be added in the Glenannan region and is included in the study. Its commercial operation date is November 2029.

5 System Studies and Results

Based upon the IC's submitted information and the area system conditions, a new switching station (referred to as "P44T") at the proposed POI on 1L384 is required to interconnect the IC's generating project to the BCH system. There are multiple terminals on the existing line 1L384. 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 P44T, the existing line 1L384 will be segregated into two new circuits, temporarily referred to as: 1L384_A (GLN-P44T) and 1L384_B (P44T-TPY). The interconnection line, to be built by the IC, is temporarily referred to as 1L384_C (P44-P44T). 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 — 32HW/33LS/33HS system conditions that include all the higher-queued generating projects ([redacted] project, [redacted] project, and [redacted] project in the region and the future proposed North Coast 500 kV transmission lines. 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 system normal conditions			
1L384_A	LS, HS, HW	P0: system normal	Rebuild line 1L384_A from POI to GLN to achieve a continuous rating of 860 A or greater at 35°C ambient.
Under contingencies			
GLN T5	LS, HS, HW	P1.3: GLN T1, T11 P2.3: GLN 2CB2, GLN 1CB6	Generation Shed or Runback RAS at [redacted]
GLN T11	LS, HS, HW	P1.3: GLN T2, T5, P2.3: GLN 2CB8, GLN 1CB7	Generation Shed or Runback RAS at [redacted]
1L384_B, 1L398, 1L396,	LS, HS, HW	P1.2 1L384_A scheduled out of service	Generation Curtailment at [redacted]
TKW T4 and T5	LS, HS	P1.2 1L384_A scheduled out of service	Generation Curtailment at [redacted]

The study identified new thermal overload on three sections of 1L384_A (POI to BRN Tap, BRN Tap to PBL Tap, and PBL Tap to GLN) under system normal condition in all heavy summer, light summer, and heavy winter loading scenarios. These line sections require higher ampacity of 860 amperes or greater at 35°C to accommodate [redacted] interconnection.

GLN T5 is overloaded under single contingency (GLN T1, GLN T11, GLN 2CB2, GLN 1CB6). Likewise, GLN T11 is overloaded under single Contingency (GLN T2, GLN T5, GLN 2CB8, GLN 1CB7). The overload could be mitigated by shedding or running back the IC's project in response to the contingencies. The exact RAS requirements will be determined in subsequent studies if the project proceeds.

1L384_B, 1L396, 1L398, TKW T4 and T5 are overloaded when 1L384_A is scheduled out of service and Houston Substation (HUS) 1D26 is closed to connect HUS and TPY. IC's generating plant needs to be limited to the appropriate level before closing 1D26. Further operation restrictions or RAS may be required for another regional contingency under this operating condition. The exact requirement will be determined in subsequent studies if the project proceeds.

5.1.2 Steady-State Voltage Analysis

With the connection of the IC's project, the steady-state voltage performance under system normal and single contingency conditions is acceptable for all the three load conditions (33LS, 33HS, 32HW). Appendix B shows the details in the steady-state voltage study results.

5.1.3 Reactive Power Capability Evaluation

The BC Hydro 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] would be capable of meeting the BC Hydro's reactive capability requirement at the plant's maximum MW output, which is subjected to further verification in the next stage of the call process.

In addition, according to the IC-provided reactive capability data, the proposed WTG would provide +1.7 Mvar to -1.9 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 call process.

5.1.4 Anti-Islanding Requirements

[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 wind farm from the grid when an inadvertent island with the local load forms.

5.1.5 Other Performance Requirements

Fast Frequency Response, also known as Virtual Inertia Control (VIC) in [redacted] wind turbines, is required at the [redacted]. 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 the call 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

A new outdoor 138 kV, 3-circuit breaker ring bus switching substation (P44T temporarily) will be built at the proposed POI, close to the existing 138 kV transmission line 1L384. The existing transmission line 1L384 will be cut and looped in to, and 138 kV line of [redacted] (1L384_C) will be terminated at the new substation.

The substation upgrade scope at the new switching substation P44T is as follows.

- Acquire adequate property for a new switching substation close to the existing transmission line 1L384.
- Construct a new outdoor 138 kV, three-circuit breaker ring bus switching substation. Refer to the one-line diagram Appendix C for details. The designations of the new switching substation and the new line connecting to the customer, as well as two new lines derived from 1L384 are temporarily assigned as P44T, 1L384_C, 1L384_A and 1L384_B. These designations are subject to revision in the next project stage.
- Construct a new control building for the switching substation and other required substation facilities and infrastructures.
- Cut the existing 1L384 and loop into the substation.
- Terminate 138kV line of [redacted] at the substation.

5.4 Transmission Line Requirements

It is required to rebuild the overhead circuit 1L384_A (from POI to GLN) to meet the required 860 Amps (35°C ambient summer Temperature) by utilizing “Mica” ACSR (at 90°C conductor temperature, 35°C ambient summer Temperature), with structure replacements. Additional right of way may also be needed.

In addition, fiber optic cables are required to be installed to meet protection, control, and telecommunication requirement from the POI to PLG along 1L384_B line structures, HUS to TKW along 1L396 line structures, from BRN to P44T along 1L384_A line structures.

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

1. A new 138 kV switching station (referred to as “P44T”) on 1L384 is required at the proposed POI for interconnecting the IC’s generating project to the BCH system. With the new switching station P44T, the existing line 1L384 will be segregated into two new circuits, temporarily referred to as: 1L384_A (GLN-P44T) and 1L384_B (P44T-TPY). The interconnection line, to be built by the IC, is temporarily referred to as 1L384_C (P44-P44T). These temporary line designations will be replaced by permanent ones at a later stage of interconnection study.
2. The study identified new thermal overload on 1L384_A line sections from POI to Glenannan substation (GLN) under system normal condition in heavy summer, light summer, and heavy winter loading scenarios. These line sections require higher ampacity of 860 amperes or greater at 35°C ambient temperature to accommodate [redacted] interconnection.
3. Rebuild of 1L384_A line sections from the POI to GLN with “Mica” ACSR conductor is required to meet the rating requirement. Additional Right of Way (ROW) may also be needed. In addition, fiber optic cables are required to be installed to meet protection, control, and telecommunication requirement from the POI to Palling capacitor station (PLG) along 1L384_B line structures, Houston substation (HUS) to Telkwa (TKW) substation along 1L396 line structures, from Burns Lake substation (BRN) to P44T along 1L384_A line structures.
4. GLN T5 is overloaded under single contingency (GLN T1, GLN T11, GLN 2CB2, GLN 1CB6). Likewise, GLN T11 is overloaded under single Contingency (GLN T2, GLN T5, GLN 2CB8, GLN 1CB7). The overload could be mitigated by a Remedial Action Scheme (RAS) which will shed or run back the IC’s project in response to the contingencies. The exact RAS requirements will be determined in subsequent studies if the project proceeds.

5. 1L384_B, 1L396, 1L398, TKW T4 and T5 are overloaded when 1L384_A is scheduled out of service and Houston substation (HUS) 1D26 is closed to connect HUS and TPY. IC's generating plant needs to be limited to the appropriate level before closing 1D26. Further operational restrictions or RAS may be required for another regional contingency under this operating condition. The exact requirement will be determined in subsequent studies if the project proceeds.
6. In addition, [redacted] will be required to be integrated in the existing BC Hydro RAS to maintain system reliability for 500 kV contingencies. The exact RAS requirements will be determined in subsequent studies if the project proceeds.
7. [redacted] 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.
8. [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 BC Hydro's TIR Section 6.4.2.
9. The "STATCOM option" for [redacted] type-3 WTGs is required so that each turbine can provide reactive power capability at zero MW output. BC Hydro recognizes that Type-3 WTGs with the STATCOM option have an inherent limitation—providing only partial reactive power capability during turbine standstill.
10. Fast Frequency Response, also known as Virtual Inertia Control (VIC) in [redacted] wind turbines is required at the [redacted]. 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 the call process.

Appendix A

Schematic Diagram of the IC's Project

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

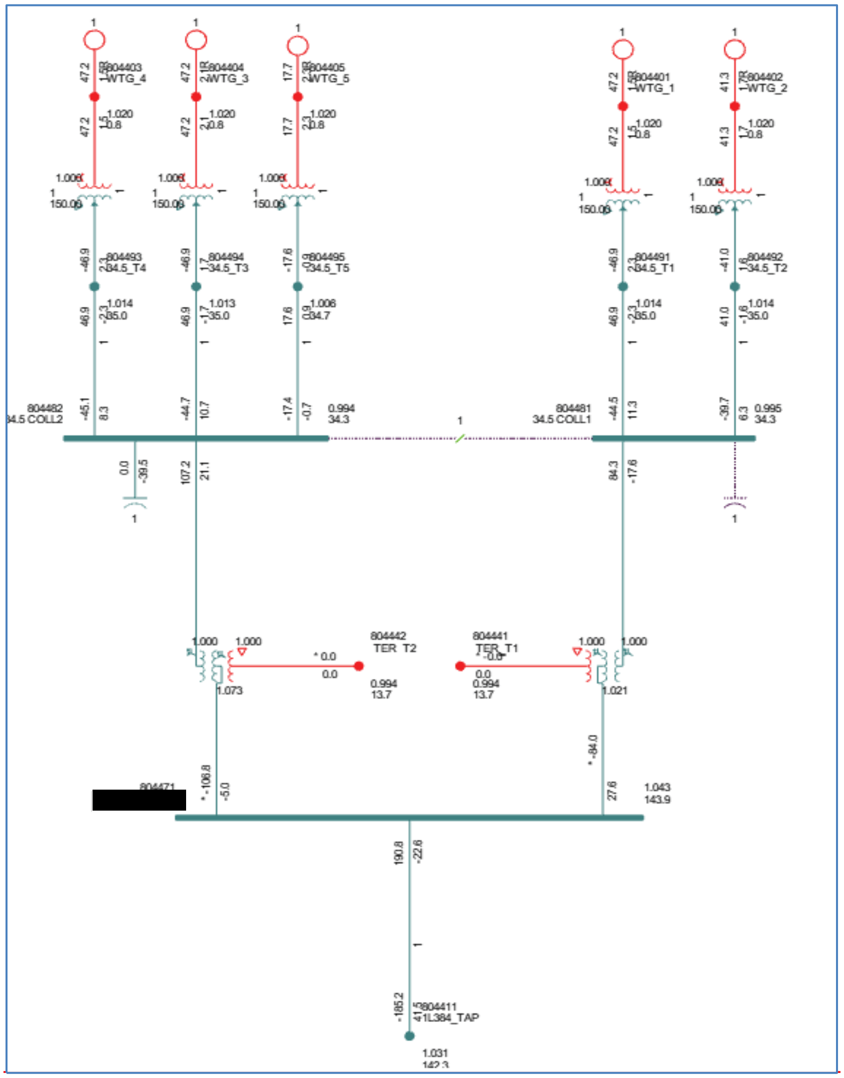

Figure A-1: [redacted] Plant Schematic Diagram.

Appendix B

Power Flow Study Results

Base Scenario (32HW/33HS/33LS)

Table B-1: Thermal Overload Study Results

Case	NC Regional Generation	Contingency		Branch Loading (% of its seasonal normal rating)								
				1L384_A	1L384_A	1L384_A	1L384_B	1L398	1L396	GLN T5	GLN T11	TKW T4/T5
		Cat.	Description	POI-BRN	BRN-PBL	PBL-GLN	POI-TPY	TPY-HUS	HUS-TKW	GLN	GLN	TKW
Winter Rating in MVA				107.6	107.6	107.6	107.6	71.7	147.7	200	178	200
32HW	Max	P0	System Normal	169 %	155%	151%	-	-	-	50%	40%	-
	Max	P1.3	GLN T1/T11[1]	-	-	-	-	-	-	87%	-	-
	Max	P1.3	GLN T2/T5[1]	-	-	-	-	-	-	-	101%	-
	Max	P1.2	1L384_A OOS	-	-	-	178%	261%	116%	-	-	98%
	Max	P2.3	GLN 2CB2	-	-	-	-	-	-	87%	-	-
	Max	P2.3	GLN 2CB8	-	-	-	-	-	-	-	101%	-
	Max	P2.3	GLN 1CB6	-	-	-	-	-	-	87%	-	-
	Max	P2.3	GLN 1CB7	-	-	-	-	-	-	-	97%	-
Summer Rating in MVA				66.9	66.9	66.9	66.9	61	120.2	168	150	168
33HS	Max	P0	System Normal	272%	265%	260%	-	-	-	64%	51%	-
	Max	P1.3	GLN T1/T11[1]	-	-	-	-	-	-	113%	-	-
	Max	P1.3	GLN T2/T5[1]	-	-	-	-	-	-	-	129%	-
	Max	P1.2	1L384_A OOS	-	-	-	283%	306%	147%	-	-	125%
	Max	P2.3	GLN 2CB2	-	-	-	-	-	-	112%	-	-
	Max	P2.3	GLN 2CB8	-	-	-	-	-	-	-	130%	-
	Max	P2.3	GLN 1CB6	-	-	-	-	-	-	113%	-	-
	Max	P2.3	GLN 1CB7	-	-	-	-	-	-	-	123%	-
Summer Rating in MVA				66.9	66.9	66.9	66.9	61	120.2	168	150	168
33LS	Max	P0	System Normal	275%	267%	255%	-	-	-	63%	50%	-
	Max	P1.3	GLN T1/T11[1]	-	-	-	-	-	-	110%	-	-
	Max	P1.3	GLN T2/T5[1]	-	-	-	-	-	-	-	127%	-
	Max	P1.2	1L384_A OOS	-	-	-	283%	306%	147%	-	-	129%
	Max	P2.3	GLN 2CB2	-	-	-	-	-	-	110%	-	-
	Max	P2.3	GLN 2CB8	-	-	-	-	-	-		127%	-
	Max	P2.3	GLN 1CB6	-	-	-	-	-	-	110%	-	-

Case	NC Regional Generation	Contingency		Branch Loading (% of its seasonal normal rating)								
				1L384_A	1L384_A	1L384_A	1L384_B	1L398	1L396	GLN T5	GLN T11	TKW T4/T5
		Cat.	Description	POI-BRN	BRN-PBL	PBL-GLN	POI-TPY	TPY-HUS	HUS-TKW	GLN	GLN	TKW
	Max	P2.3	GLN 1CB7	-	-	-	-	-	-	-	121%	-
Note 1: T1 and T11 share the same tripping zone, T2 and T5 share the same tripping zone.												

Table B-2: Steady-State Voltage Study Results

Case	IC's Plant Output	Contingency		Bus Voltage (PU)		
		Cat.	Description	GLN 230	GLN 138	PBL 138
32HW	Max	P0	System Normal	1.04	1.017	0.996
	Max	P1.3	GLN T2/T5[1]	1.05	1.001	0.990
33HS	Max	P0	System Normal	1.05	1.020	0.999
	Max	P1.3	GLN T2/T5[1]	1.05	1.004	0.994
33LS	Max	P0	System Normal	1.05	1.020	0.999
	Max	P1.3	GLN T2/T5[1]	1.05	1.006	0.996

Note 1: T1 and T11 share the same tripping zone, T2 and T5 share the same tripping zone

Appendix C

One-Line Sketch for New Switching Substation

Figure C-1 shows the Stations Planning One-Line Sketch for the New Switching Substation P44T.

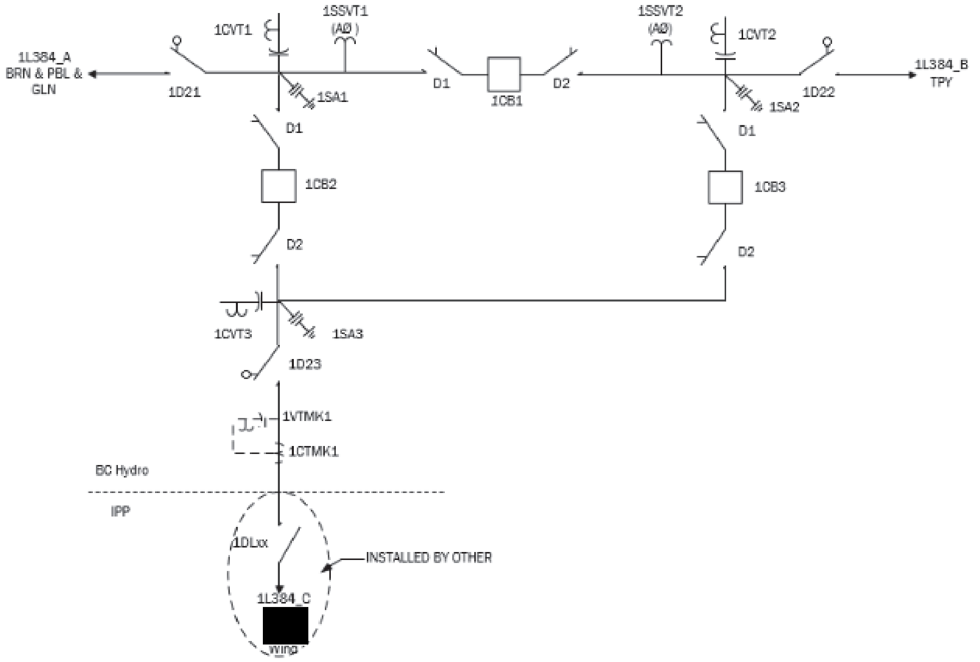

Figure C-1: Stations Planning One-Line Sketch for the New Switching Substation P44T.