

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

November 24, 2025

[REDACTED]

via email: [REDACTED]

**RE: CEAP IR #24 – [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 \$34.1 M.

### **Major Scope of Work Identified:**

- Add one 230 kV line position with associated equipment including two circuit breakers and disconnect switches at BC Hydro's Glennan substation (GLN)
- Expand 230 kV existing 2MB2 main bus to facilitate new 230 kV line position
- Terminate [REDACTED] line with associated disconnect, surge arrester and capacitor voltage transformer

- Upgrade required substation facilities, infrastructures, and bus work to support new station equipment, including expansion of the station footprint
- Supply and install required Protection, Control and Telecommunications equipment

**Exclusions:**

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

**Key Assumptions:**

- Construction by contractor
- 12 months of construction is considered
- No construction during winter season
- Execution of early Engineering and Procurement Agreement
- No expansion of control buildings to accommodate new equipment
- Impact Benefit Agreements with First Nations are not considered

**Key Risks:**

- 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

**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 2031 (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](mailto:ceap2025@bchydro.com).

Sincerely,

[Redacted signature]

[Redacted name]

Manager, Customer Interconnections

BC Hydro

Encl.: CEAP\_2025\_IR24\_[Redacted]\_Feasibility\_Study.pdf



# Interconnection Feasibility Study

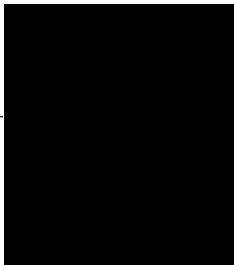
**BC Hydro EGBC Permit to Practice No: 1002449**

**2025 CEAP IR # 24**

Prepared for:

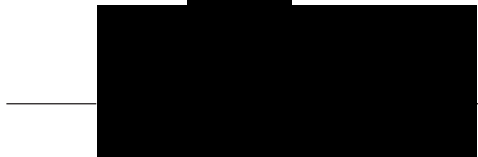


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Accepted by:



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## Report Metadata

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Revision	Date	Description
0	2025 Nov	Initial release

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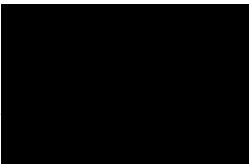
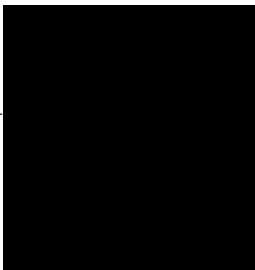
**Section:**

Entire report  
except listed  
below

**Discipline:**

Transmission Planning

Contributed by:

  
Specialist Engineer, Transmission  
Planning 

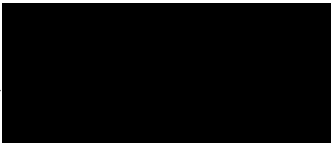
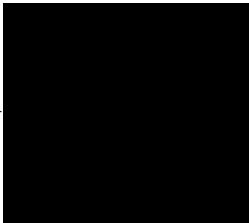
**Section:**

5.2, 5.3

**Discipline:**

Stations Planning

Contributed by:

  
Specialist Engineer, Station Planning 

## Executive Summary

[REDACTED], the interconnection customer (IC), requests to interconnect its [REDACTED] (2025 CEAP IR: # 24) to the BC Hydro (BCH) system. [REDACTED] has thirty-two (32) [REDACTED] type-3 wind turbine generators with a maximum power injection of 176 MW into the BC Hydro system at the Point of Interconnection (POI). The proposed Point of Interconnection (POI) is on BC Hydro's Glenannan substation (GLN). The IC's project will connect to the POI via a 32 km 230 kV interconnection line. The IC's proposed commercial operation date (COD) is Nov. 1, 2029.

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 line position is required at GLN substation to facilitate the interconnection of [REDACTED]. The 230 kV line position shall have an independent switching and protection zone.
2. The connection of [REDACTED] does not cause any performance violation (i.e. thermal overload, voltage performance violation or voltage stability concern) under system normal and N-1 contingency operating conditions.
3. [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.
4. The impact on BC Hydro bulk transmission system is not part of the project scope of the feasibility study. However, it should be noted that [REDACTED] is required to participate in the existing BC Hydro generation shedding RAS to address various performance issues for contingencies in BC Hydro's 500 kV transmission system.
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 BC Hydro's TIR Section 6.4.2.

6. The "STATCOM option" for the proposed 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.
7. Fast Frequency Response, also known as Virtual Inertia Control (VIC) in the proposed 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 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".

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## Appendices

Appendix A	Schematic Diagram of the IC's Project
Appendix B	Power Flow Study Results
Appendix C	One-Line Sketch for GLN Station

## Acronyms

The following are acronyms used in this report.

BCH	BC Hydro
BWM	Black Water Mine
CEAP	Competitive Electricity Acquisition Process
COD	Commercial Operation Date
DTT	Direct Transfer Trip
ERIS	Energy Resource Interconnection Service
FeS	Feasibility Study
FGE	Fort St. James Generating Station
FKR	Forrest Kerr Generating Station
GLN	Glenannan Substation
GTTT	Glenannan to Terrace Transmission Project
IBR	Inverter-Based Resources
IC	Interconnection Customer
IPP	Independent Power Producer
IR	Interconnection Request
ISD	In Service Date
KIT	Kitimat Substation
KMO	Kemano Generating Station
MCY	McLymont Creek Generating Station
MPO	Maximum Power Output
NC	North Coast
NERC	North American Electric Reliability Corporation
	
NRIS	Network Resource Interconnection Service
OATT	Open Access Transmission Tariff
PGGT	Prince George to Glenannan Transmission Project
PGTC	Prince George Capacitor Bank Project
PLG	Palling Station
POI	Point of Interconnection
RAS	Remedial Action Scheme

SNV	Saranovich Station
TAC	Tachick Substation
TIR	BC Hydro “60 kV to 500 kV Technical Interconnection Requirements for Power Generators”
TKW	Telkwa Substation
TVC	Transmission Voltage Customer
VIC	Virtual Inertia Control
VOL	Volcano Creek Generating Station
WECC	Western Electricity Coordinating Council
WSN	Williston Substation
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)	GLN	
IC's Proposed COD	1st November 2029	
Type of Interconnection Service	NRIS <input checked="" type="checkbox"/>	ERIS <input type="checkbox"/>
Maximum Power Injection (MW)	176 MW (Summer)	176 MW (Winter)
Number of Turbines	32 x 5.7 MW WTGs	
Plant Fuel	Wind	

[REDACTED] the interconnection customer (IC), requests to interconnect its [REDACTED] (2025 CEAP IR # 24) to the BC Hydro system. [REDACTED] has thirty-two (32) the proposed [REDACTED] type-3 wind turbine generators with a maximum power injection of 176 MW into the BC Hydro system at the Point of Interconnection (POI). The IC's proposed POI is on BC Hydro's GLN 230 kV. The IC's project will connect to the POI via a 32 km 230 kV interconnection line. The proposed commercial operation date (COD) is Nov. 1, 2029.

Figure 1-1 shows the Glenannan (GLN) Regional transmission system diagram. GLN is a major station approximately 175 km from Williston Substation (WSN) located in BC Hydro's North Coast (NC) region. GLN is connected to WSN via 500 kV line 5L61, and it is connected to Telkwa Substation (TKW) via a 500 kV line 5L62. The Williston-Glenannan-Telkwa-Skeena 500 kV transmission system is a radial system starting from WSN, with various IPP generation and customer loads surrounding the series of 500 kV and 230 kV transmission lines, including major loads at Kitimat (KIT), and key regional generation resources such as Kemano (KMO), Forrest Kerr Generating Station (FKR), Volcano Creek Generating Station (VOL), and McLymont Creek Generating Station (MCY). In Figure 1-1, [REDACTED] (2025 CEAP IR # 24) is highlighted by P24 in red color and an ongoing 500 KV transmission system reinforcement project include series compensation at PLG and SNV are also shown in red color.

GLN is a 500 kV substation in the North Coast region, which includes:

- Two 500/230 kV transformers (GLN T1 & T2)
- Two 230/138 kV transformers (GLN T5 & T11)
- Three 138/66 kV transformers (GLN T3, T4 & T6)

GLN has two existing 230 kV line connections, line 2L353 to Tachick Substation (TAC), which further connects to the 66 kV system including a customer IPP Fort St. James (FGE) generating station, and the other line 2L355 to a TVC load BWM.

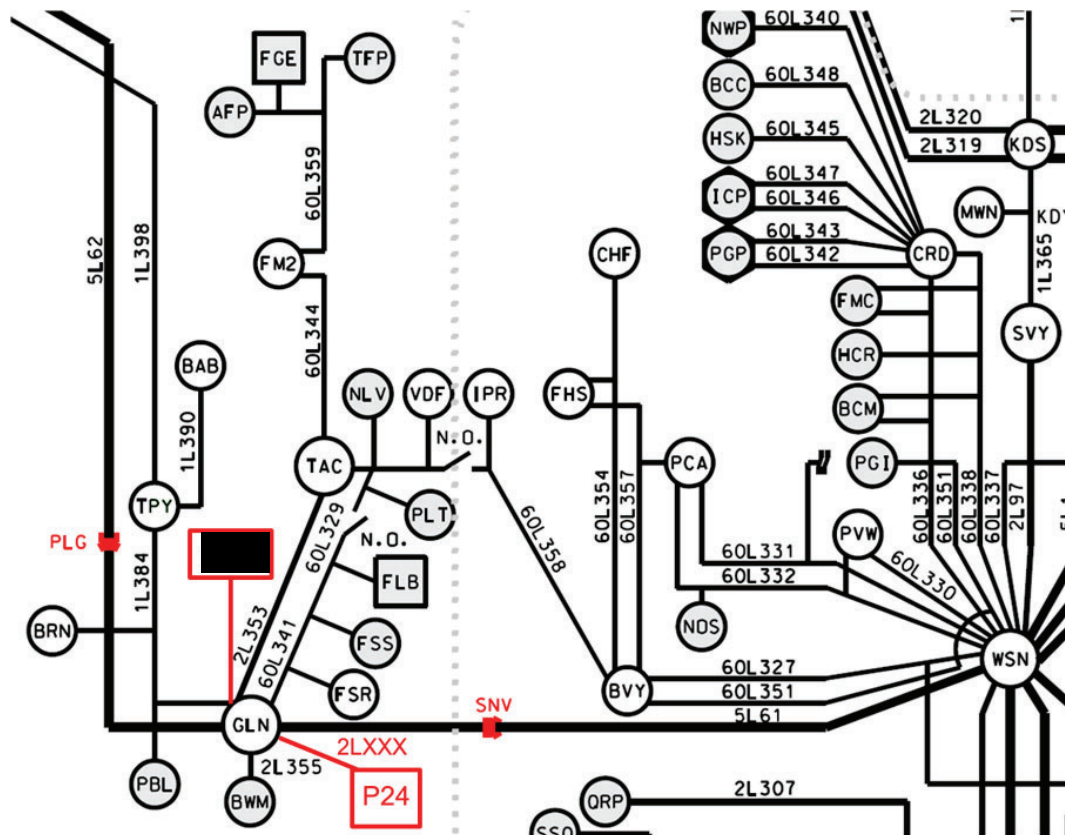


Figure 1-1: [Redacted] and the Surrounding Area

There are few planned capital projects to reinforce bulk transmission system in NC region, and they are presented below for an information purpose.

- Prince George Capacitor Bank Project (PGTC) is the major capital project under construction, which will add series compensation for 5L61, 5L62, and 5L63 and a new 500KV/230KV transformer at SKA. Scheduled ISD is in Oct. 2027.
- Prince George to Glenannan Transmission Project (PGGT) Project will construct 500 kV line - 5L64 from Williston to Glenannan substation. Scheduled ISD is in Oct. 2030.
- Glenannan to Terrace Transmission Project (GTTT) will construct two 500 kV lines - 5L65 and 5L66 from Glenannan to Skeena substation. Scheduled ISD is in Oct. 2031.
- 5L61/62/63 thermal upgrades project. Scheduled ISD is in Oct. 2031.

There is one new wind farm, [REDACTED] project with a capacity of 205.2 MW to be added in the GLN region, which is one of the successful projects from the 2024 power call. The NMW project has a COD in October 2030. It is also shown in Figure 1-1 in red.

## 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 2025 CEAP 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 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) RTA to BCH power transfer is set to 420 MW to achieve higher power transfer from GLN to WSN.
- 3) There is an ongoing 500 KV transmission reinforcement project: PGTC which includes series compensations on 5L61, 5L62, and 5L63, and a new 500KV/230KV transformer SKA T3. This project will be in service by Oct. 2027, and it has been taken into account in this study.
- 4) [REDACTED] Wind project has the POI at GLN 230 kV. The [REDACTED] Wind project is included in power flow cases for this study [REDACTED].

## 5 System Studies and Results

### 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 — 29HW/30LS/30HS system conditions. 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

For all the studied load conditions (29HW, 30LS, 30HS) there is no branch overload identified under system normal condition (P0) and single contingency conditions (P1 and P2). Appendix B shows the details in the branch loading study results.

#### 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 (30LS, 30HS, 29HW). 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] [REDACTED] would be capable of meeting the BC Hydro's reactive



- Add two new 230 kV circuit breakers with associated disconnects to create line position for the [REDACTED] customer.
- Terminate [REDACTED] 230 kV 2LXXX transmission line with associated disconnect, surge arrester and capacitor voltage transformer.
- Expand the control building, if required, to accommodate new P&C panels and other equipment.
- Expand the existing 230kV switchyard within the limits of the current property boundaries.
- Other associated station work.

Refer to one line sketch in Appendix C for details.

## 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 230 kV line position is required at GLN substation to facilitate the interconnection of [REDACTED]. The 230 kV line position shall have an independent switching and protection zone.
2. The connection of [REDACTED] does not cause any performance violation (i.e. thermal overload, voltage performance violation or voltage stability concern) under system normal and N-1 contingency operating conditions.
3. [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.
4. The impact on BC Hydro bulk transmission system is not part of the project scope of the feasibility study. However, it should be noted that [REDACTED] is required to participate in the existing BC Hydro generation shedding RAS to address various performance issues for contingencies in BC Hydro's 500 kV transmission system.
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 BC Hydro's TIR Section 6.4.2.
6. The "STATCOM option" for the proposed 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.
7. Fast Frequency Response, also known as Virtual Inertia Control (VIC) in the proposed 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 interconnection process.

## Appendix A

### Schematic Diagram of the IC's Project

Figure A-1 shows the schematic diagram for the [REDACTED]. Note that the proposed plant configuration includes two (2) 16 MVar mechanically switched capacitor banks at 34.5 kV collector buses.

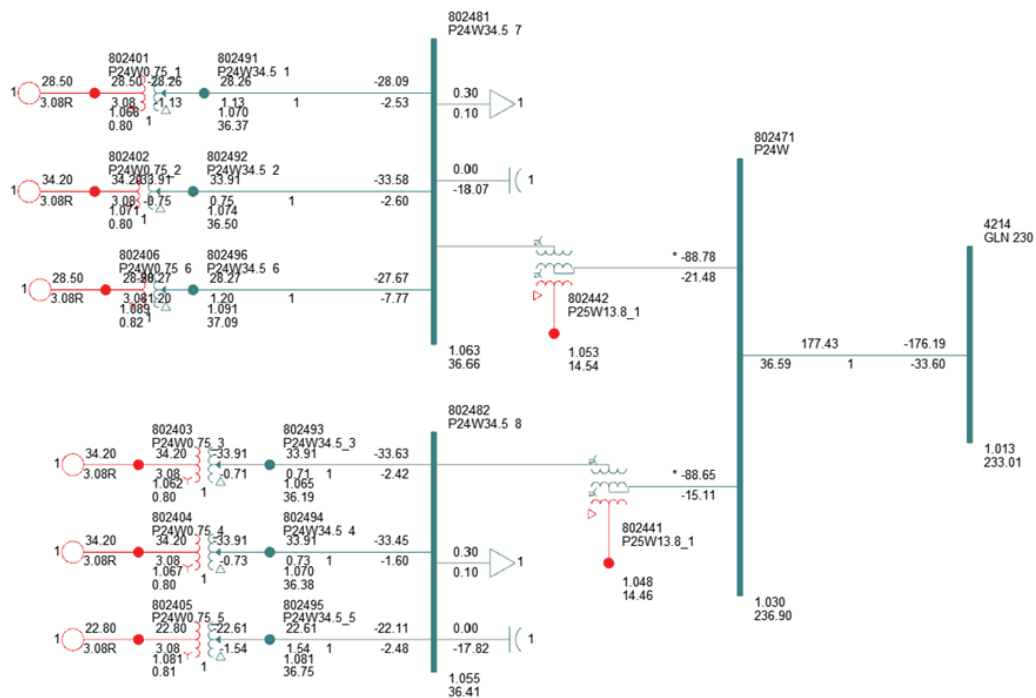


Figure A-1: [REDACTED] Schematic Diagram.

## Appendix B

### Power Flow Study Results

**Table B-1: Thermal Overload Study Results**

Case	IC's Plant Output	Contingency		Branch Loading	
		Category	Description	GLN T1 500/230KV	2L353 GLN-TAC
Winter Rating (MVA)				714	119.5
29HW	0	P0	System Normal	9%	20%
	MAX	P0	System Normal	21%	19%
	MAX	P1.3	GLN T2&T5 (Note 1)	41%	19%
	MAX	P2.3	GLN 1CB2 (Note 2)	45%	19%
Summer Rating (MVA)				600	119.5
30HS	0	P0	System Normal	13%	21%
	MAX	P0	System Normal	27%	22%
	MAX	P1.3	GLN T2&T5	54%	20%
	MAX	P2.3	GLN 1CB2	57%	20%
30LS	0	P0	System Normal	14%	24%
	MAX	P0	System Normal	28%	24%
	MAX	P1.3	GLN T2&T5	56%	25%
	MAX	P2.3	GLN 1CB2	58%	24%

Note 1: GLN T2 and GLN T5 are in the same protection zone.

Note 2: GLN 1CB2 internal fault results in loss of GLN T2, T5 and 1L384.

**Table B-2: Steady-State Voltage Study Results**

Case	IC's Plant Output	Contingency		Bus Voltage (PU)	
		Category	Description	GLN 500 KV	GLN 230 KV
29HW	0	P0	System Normal	1.048	1.031
	MAX	P0	System Normal	1.048	1.027
	MAX	P1.3	GLN T2&T5	1.047	1.027
	MAX	P2.3	GLN 1CB2	1.048	1.027
30HS	0	P0	System Normal	1.042	1.025
	MAX	P0	System Normal	1.042	1.022
	MAX	P1.3	GLN T2&T5	1.041	1.023

	MAX	P2.3	GLN 1CB2	1.041	1.022
30LS	0	P0	System Normal	1.035	1.018
	MAX	P0	System Normal	1.037	1.018
	MAX	P1.3	GLN T2&T5	1.035	1.019
	MAX	P2.3	GLN 1CB2	1.035	1.019

