BC Hydro
Power smart

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

November 24, 2025

[redacted]

via email: [redacted]

RE: CEAP IR #102 – [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 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 $922.7 M.

Major Scope of Work Identified:

- Install a new approximately 150 km 230 kV transmission circuit (temporarily designated as 2L15X) from Dunsmuir substation (DMR) to Gold River substation (GLD)
- Secure right of way for new 230 kV transmission circuit 2L15X
- Complete the following at BC Hydro's GLD substation

  - Expand the existing substation to be within BC Hydro property boundary
  - Expand the existing 230 kV switchyard to add new four circuit breaker ring bus configuration
  - Add a new 230 kV line position for new 2L15X line from GLD to DMR
  - Add a new 230 kV line position for the Interconnection Customer's proposed 230 kV transmission line
  - Re-terminate 2L154A (i.e. existing 2L154) circuit with associated equipment in the new 230 kV bus
  - Re-terminate the 230 kV side of GLD T1 and T4 transformers in the new ring bus position
  - Add a new 230 kV mechanically switched shunt reactor and associated equipment
  - Expand the existing control building, if required, to accommodate new P&C panels and other equipment
  - Upgrade required substation facilities, infrastructures, and bus work to support new station equipment
- Complete the following at BC Hydro's DMR substation
  - Add a new 230 kV line position for 2L15X and associated equipment such as circuit breakers and disconnects.
  - Expand the existing substation to be within BC Hydro property boundary, if needed
  - Expand the existing control building, if required, to accommodate new P&C panels and other equipment
  - Upgrade required substation facilities, infrastructures, and bus work to support new station equipment
- Supply and install required Protection, Control and Telecommunications equipment

Exclusions:

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

Key Assumptions:

- Construction by contractor
- 30 months of construction is considered
- Execution of early Engineering and Procurement Agreement
- No expansion of existing other stations or control buildings to accommodate new equipment
- No construction during winter season
- Impact Benefit Agreements with First Nations are not considered
- A certificate of public convenience and necessity (CPCN) requirement will be exempt

Key Risks:

- Expansion of the existing other substations and/or control building may lead 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
- Transmission scope and routing may be different than assumed, including number of structures and types
- Ability to acquire new Right-of-Way
- 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

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]

[redacted]

BC Hydro

Encl.: CEAP_2025_IR102_[redacted]_Feasibility_Study.pdf

[redacted]

Interconnection Feasibility Study

BC Hydro EGBC Permit to Practice No: 1002449

2025 CEAP IR # 102

Prepared for: [redacted]

Prepared by: [redacted] [redacted]

Engineer, Transmission Planning

Reviewed by: [redacted]

Technical Strategic Principle, Transmission Planning

Accepted by: [redacted]

Division Manager, Transmission Planning

BC Hydro
Power smart

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Executive Summary

[redacted] the Interconnection Customer (IC), requests to interconnect its [redacted] - 2025 CEAP IR # 102 - to the BC Hydro (BCH) system. [redacted] has sixty (60) [redacted] type-4 wind turbine generators, adding a total installed capacity of 252 MW with a maximum power injection of 235.5 MW into BC Hydro transmission system at the proposed Point of Interconnection (POI). The proposed POI is on BC Hydro's 230 kV bus at the Gold River Substation (GLD). The IC's project will connect to the POI via a customer-built 230 kV 113 km overhead and a 24 km submarine cable. The IC's proposed commercial operation date (COD) is July 7, 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. The proposed POI at the 230 kV bus of GLD is acceptable to interconnect the IC's generating project to the BCH system.
2. The connection of [redacted] causes performance violations such as thermal overload on 2L154 under system normal conditions. A new 230 kV circuit from Dunsmuir Substation (DMR) to GLD will be required.
3. For single contingency conditions, the study has observed thermal overloads on 1L120, 1L121, or 2L154. The [redacted] will need to participate in and modify the existing north Vancouver Island 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. To mitigate the potential high voltage issue, a 75 MVAr 230 kV mechanically switched shunt reactor with AutoVAr control scheme is required to be installed at GLD 230 kV bus.
5. [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.

6. 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.
7. 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.
8. Fast Frequency Response (FFR), as per BCH TIR Section 6.4.5, is required at the IC's Wind Project. The proposed wind turbine generators, when the FFR function is enabled, are expected to temporarily boost the MW output to limit the system frequency drop during a major frequency event. The FFR settings should be determined in coordination with BC Hydro in the later stage of 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
FeS	Feasibility Study
IBR	Inverter-Based Resources
IC	Interconnection Customer
IR	Interconnection Request
LAPS	Local Area Protection Schemes
MPO	Maximum Power Output
NERC	North American Electric Reliability Corporation
NRIS	Network Resource Interconnection Service
NVI	North Vancouver Island
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)	GLD 230 kV station	
IC's Proposed COD	7th July 2030	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	235.5 MW (Summer)	235.5 MW (Winter)
Number of Turbines	60 x 4.2 MW WTGs	
Plant Fuel	Wind	

[redacted] the Interconnection Customer (IC), requests to interconnect its [redacted] - 2025 CEAP IR # 102 - to the BC Hydro system. [redacted] has sixty (60) [redacted] type-4 wind turbine generators, adding total installed capacity of 252 MW with a maximum power injection of 235.5 MW into BC Hydro transmission system at the proposed Point of Interconnection (POI). The IC's proposed POI is at the 230 kV bus of the Gold River Substation (GLD). The IC's project will connect to the POI via a 113 km 230 kV overhead line and a 24 km 230 kV submarine cable. The proposed commercial operation date (COD) is July 7, 2030.

Figure 1-1 shows the North Vancouver Island (NVI) region transmission system diagram. The NVI 132/230 kV system has existing branch overload concerns under contingency conditions. These constraints are primarily driven by excessive generation in the region. A remedial action scheme (RAS), named the North Vancouver Island Remedial Action Scheme (NVI RAS), is implemented to address the thermal overloads on 1L120 (GLD-Strathcona Generating Station (SCA)) and other 132 kV lines under the contingency of loss current 2L154 (GLD-Dunsmuir Substation (DMR)) during high Cape Scott Wind (CSS) and [redacted]-Kokish River (KKS) generation conditions. This RAS will runback the CSS and KKS generations.

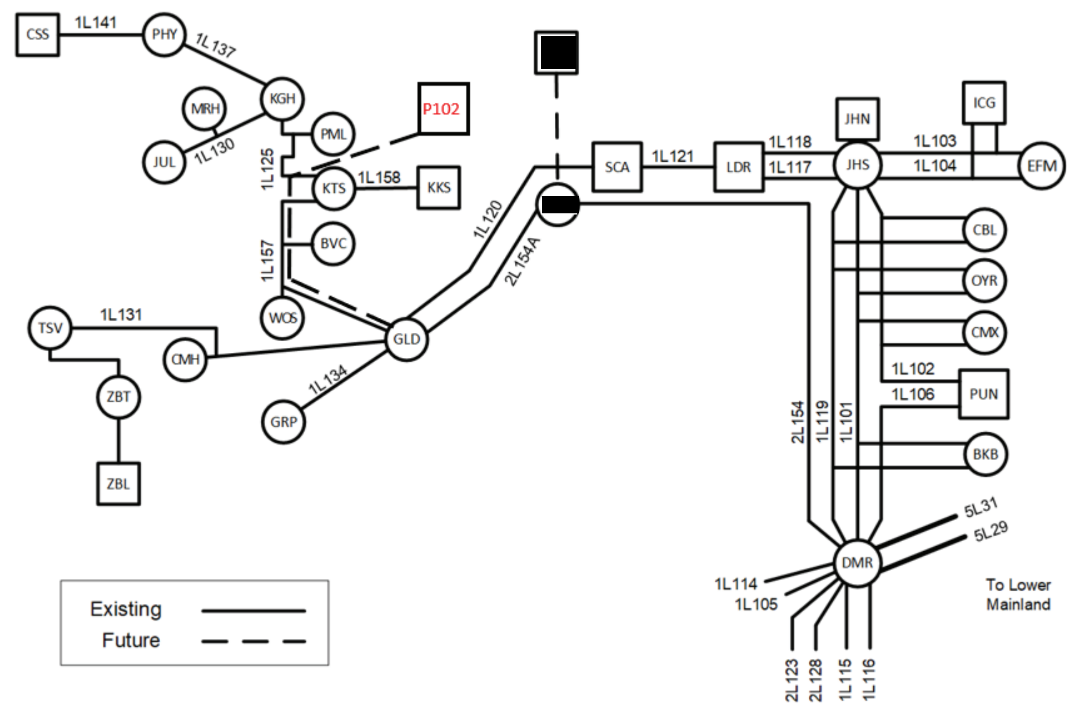

Figure 1-1: North Vancouver Island Region Transmission System Diagram

In addition, a new, higher queued wind generating facility, [redacted] will be added to the NVI region. To interconnect [redacted] to the BC Hydro system, a new switching station ([redacted] will be constructed on transmission line 2L154, near Strathcona Generating Station. The commercial operation date is targeted for December 2028, with maximum injected power of 189.3 MW. [redacted] will also participate in the NVI RAS. The existing 2L154 will be split into two line sections, referred to as 2L154 (BTT-DMR) and 2L154A (GLD-BTT).

There are no other relevant capital projects or confirmed load interconnections in the study area.

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) The [redacted] wind farm is included in the study model. It is expected to be in service on September 30, 2028.

3) For the purpose of performing this study, it is assumed that it is feasible to install new 230 kV line positions at GLD.

4) It is assumed that adequate right-of-way is available for BC Hydro to build a new 230 kV line from GLD to DMR.

5 System Studies and Results

Based upon the IC's submitted information and the area system conditions, a new line position at the proposed POI on GLD 230 kV bus is required to interconnect the IC's generating project to the BCH system.

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 — 31HW/32LS/32HS system conditions that include the higher-queued generating project [redacted] in the region. 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

The study identified significant branch overloads under system normal condition (P0) and contingency conditions (P1 & P2) for all the studied load conditions (31HW, 32LS and 32HS).

Under system normal condition, the study identified thermal overloads on line 1L121 for 31HW, and on lines 1L121 and 2L154 for 32LS and 32HS.

To mitigate the thermal constraints during the system normal operating conditions, a new 230 kV transmission circuit (temporarily designated as 2L15X), approximately 150 km, from DMR to GLD, is required.

Under single contingency conditions, additional overloads were observed on lines 1L120, 1L121, and 2L154. The [redacted] is required to participate in and modify the existing NVI RAS.

Details of the thermal overload analysis are provided in Appendix B.

5.1.2 Steady-State Voltage Analysis

The voltage performance under system normal condition (P0) for the light summer load condition, 32LS, high voltage is observed. Moreover, single contingencies (P1&P2) on the 132 kV system cause voltage instability in the regional transmission system.

There is a system performance concern under a 132 kV internal breaker fault at DMR. The connection of the IC's project exacerbates this existing issue, contributing to potential voltage instability in the NVI region.

Additionally, under single contingency loss of 1L121 (SCA-Ladore Falls Generating Station (LDR)), low voltages have been identified at GLD 230 kV bus.

To mitigate the potential high voltage issue, a 75 MVAr 230 kV mechanically switched shunt reactor with AutoVAr control scheme is required to be installed at GLD 230 kV bus.

The proposed reinforcement plans to address the system normal thermal overloads in the section 5.1.1, along with the modified NVI RAS, will be relied upon to mitigate these low-voltage and voltage instability concerns.

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 interconnection 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 (FFR), as per BCH TIR Section 6.4.5, is required at the [redacted]. The proposed wind turbine generators, when the FFR function is enabled, are expected to temporarily boost the MW output to limit the system frequency drop during a major frequency event. The FFR settings should be determined in coordination with BC Hydro in the later stage of the interconnection process.

5.2 Fault Analysis

The short circuit analysis in the FeS 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 scope of work at GLD substation is summarized below:

- Expand the existing substation to be within BC Hydro property boundary.
- Expand the existing 230 kV switchyard to add new four circuit breaker ring bus configuration.
- Add a new 230 kV line position for new 2L15X line from GLD to DMR.
- Add a new 230 kV line position for [redacted]
- Re-terminate 2L154A (i.e. existing 2L154) circuit with associated equipment in the new 230 kV bus.
- Re-terminate the 230 kV side of GLD T1 and T4 transformers in the new ring bus position.
- Add a new 75 MVAr 230 kV mechanically switched shunt reactor and associated equipment. According to the requirement of Transmission Planning, it is acceptable for the shunt reactor shares the same protection zone with the customer-built transmission line.
- Expand the existing control building, if required, to accommodate new P&C panels and other equipment.
- Other associated station work.

The scope of work at DMR substation is summarized below:

- Add a new 230 kV line position for 2L15X (GLD to DMR) and associated equipment such as circuit breakers and disconnects.
- If needed, expand the existing substation to be within BC Hydro property boundary.
- Expand the existing control building, if required, to accommodate new P&C panels and other equipment.
- Other associated station work.

Refer to the one-line diagrams Appendix C for details.

5.4 Transmission Line Requirements

A new 230 kV transmission circuit, approximately 150 km, from DMR to GLD, is required. New Right-of-Way is required for this new 230kV circuit. The minimum continuous ampacity rating of the new 230 kV circuit is 1009 Amps in Summer (ratings should be equivalent to or exceed existing line 2L154, considering cost-benefit trade-offs across various conductor sizes).

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. The proposed POI at the 230 kV bus of GLD is acceptable to interconnect the IC's generating project to the BCH system.
2. The connection of [redacted] causes performance violations such as thermal overload on 2L154 under system normal conditions. A new 230 kV circuit from DMR to GLD will be required.
3. For single contingency conditions, the study has observed thermal overloads on 1L120, 1L121, or 2L154. The [redacted] will need to participate in and modify the existing north Vancouver Island remedial action scheme to secure the system. The RAS function scope will be specified in the System Impact Study if the need for RAS is determined.
4. To mitigate the potential high voltage issue, a 75 MVAr 230 kV mechanically switched shunt reactor with AutoVAr control scheme is required to be installed at GLD 230 kV bus.
5. [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.
6. 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.
7. 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.
8. Fast Frequency Response (FFR), as per BCH TIR Section 6.4.5, is required at the IC's wind project. The proposed wind turbine generators, when the FFR function is enabled, are expected to temporarily boost the

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

Appendix A
Schematic Diagram of the IC's Project

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

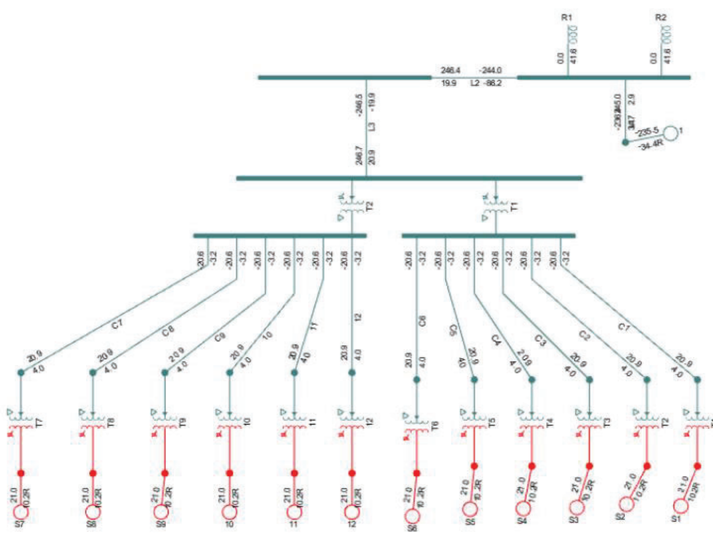

Figure A-1: [redacted] Plant Schematic Diagram.

Appendix B
Power Flow Study Results

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

Table B-1: Thermal Overload Study Results

Cases	IC's Gen Output	Contingency		Branch Loading (Amps)			
				2L154A	2L154	1L120	1L121
		Cate.	Description	GLD-BTT	BTT-DMR	GLD-SCA	SCA-LDR
Winter Ratings				844	1304	768	740
31HW	Max	P0	System Normal	547.4 65 %	986.3 76 %	616.9 81 %	849.2 108 %
		P1	2L154A_GLD-BTT	N/A	473.4 36 %	1075.4 140 %	128.6 164 %
		P1	2L154_BTT-DMR	N/A	N/A	1075.2 140 %	1283.2 164 %
		P1	1L120_GLD-SCA	966.1 114 %	1444.1 111 %	N/A	253.5 32%
		P1	1L121_SCA-LDR	1215.4 144 %	1744.4 134 %	256.6 33 %	N/A
Summer Ratings				844	1009	635	639
32HS	Max	P0	System Normal	644.3 76 %	1078 107 %	561.8 88 %	804.2 126 %
		P1	2L154A_GLD-BTT	N/A	474.1 47%	1085.5 171%	1306.6 204%
		P1	2L154_BTT-DMR	N/A	N/A	1093.7 172 %	1310.9 205 %
		P1	1L120_GLD-SCA	1048.4 124 %	1539.4 153 %	N/A	255 40 %
		P1	1L121_SCA-LDR	1290.4 153 %	1837.1 182 %	257.6 41 %	N/A
32LS	243.7	P0	System Normal	680.1 81 %	1116.4 111 %	534.1 84 %	782.5 122 %
		P1	2L154A_GLD-BTT	N/A	474.9 47 %	1092.5 172 %	1319.9 207 %
		P1	2L154_BTT-DMR	N/A	N/A	1092.3 172 %	1319.9 207 %
		P1	1L120_GLD-SCA	1076.3 128 %	1571.3 156 %	N/A	258.1 40 %
		P1	1L121_SCA-LDR	1324.2 157 %	1880.5 186 %	260.5 41 %	N/A

Table B-2: Steady-State Voltage Study Results

Case	IC's Gen Output	Contingency		Bus Voltage (PU)	
		Cate.	Description	GLD 230	GLD 132
31HW	Max	P0	System Normal	1.01	1.07
		P1	2L154A_GLD-BTT	0.97	1.07
		P1	2L154_BTT-DMR	0.97	1.07
		P1	1L120_GLD-SCA	0.94	1.07
		P1	1L121_SCA-LDR	0.87	1.04
32HS	Max	P0	System Normal	1.00	1.07
		P1	2L154A_GLD-BTT	0.96	1.07
		P1	2L154_BTT-DMR	0.97	1.06
		P1	1L120_GLD-SCA	0.92	1.07
		P1	1L121_SCA-LDR	0.86	1.02
32LS	Max	P0	System Normal	1.00	1.06
	0	P0	System Normal- No Wind	1.09	1.08
	Max	P1	2L154A_GLD-BTT	0.96	1.07
		P1	2L154_BTT-DMR	0.96	1.07
		P1	1L120_GLD-SCA	0.91	1.07
		P1	1L121_SCA-LDR	0.85	1.01

Appendix C
One-Line Sketch GLD and DMR Substations

Figure C-1 shows the Stations Planning One-Line Sketch for the GLD Substation.

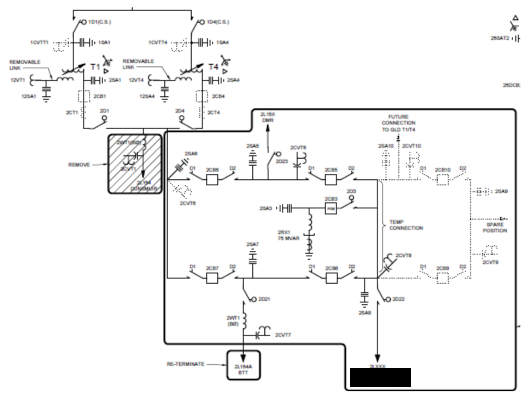

Figure C-1: Stations Planning One-Line Sketch for the GLD Substation.

Figure C-2 shows the Stations Planning One-Line Sketch for the DMR Substation.

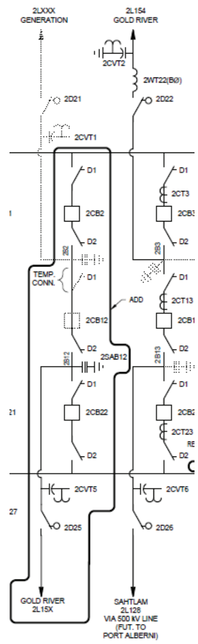

Figure C-2: Stations Planning One-Line Sketch for the DMR Substation.