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

November 24, 2025

[redacted]

via email: [redacted]

RE: CEAP IR #65 – [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 $69.0 M.

Major Scope of Work Identified:

- Thermal upgrade of 1L363 line section from Gordon M. Shrum G. S. (GMS) to P65 POI, approximately 7 km with a higher ampacity of 850 amperes minimum summer continuous rating
- 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
- Full line thermal upgrade including reconductoring and structure replacements (7km) are assumed
- Impact Benefit Agreements with First Nations are not considered
- The customer will connect to a future third party-built transmission line, and it will be in-service and operated to 138kV before the in-service date of this project

Key Risks:

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

Unique Project Considerations

BC Hydro's current understanding is that the transmission line owned by a third-party and connected to BC Hydro's 1L363 is planned for conversion to 230 kV prior to your project's requested Commercial Operation Date (COD) of October 1, 2029. This Interconnection Feasibility Study assumes that the third-party line will remain at its initial 138 kV configuration and will not operate at 230 kV before October 1, 2029, and that your project's line will permanently operate at 138 kV from 1L363 and the third-party line. If this assumption changes, the results of this Interconnection Feasibility Study will no longer be valid.

BC Hydro was unable to assess the impact of your project converting from 138 kV to 230 kV because the Interconnection Request did not include sufficient information. Such impacts can only be evaluated during the System Impact Study, once additional details and accurate information regarding the third-party system and the timing of the 230 kV conversion are provided. This Interconnection Feasibility Study does not confirm the feasibility or identify Network Upgrades for your IR connecting to the BC Hydro system at 230 kV via third-party interconnection facilities.

Since the feasibility of 230 kV conversion was not studied and the transmission line connected to BC Hydro system is owned by a third party, BC Hydro cannot confirm the feasibility of your project connecting to a third-party-owned 230 kV line via a tap connection. It is possible that a three-breaker ring switching station may be required. If so, the costs associated with a new switching station would be considered Interconnection Customer Interconnection Facilities (ICIF) as long as it is located between the Generating Facility and the Point of Change of Ownership, and therefore your responsibility.

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Power smart

Indirect Interconnection

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

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]

Manager, Customer Interconnections

BC Hydro

Encl.: CEAP_2025_IR65_[redacted]Feasibility_Study.pdf

[redacted]

Interconnection Feasibility Study

BC Hydro EGBC Permit to Practice No: 1002449

2025 CEAP IR #65

Prepared for: [redacted]

Prepared by: [redacted]

[redacted]

[redacted]
Specialist Engineer, Transmission

Reviewed by: [redacted]

[redacted].
Technical Strategic Principle, Transmission Planning

Accepted by: [redacted]

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Division Manager, Transmission Planning

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Revision	Date	Description
0	2025 Nov	Initial release

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Section: **5.2, 5.3**

Discipline: Stations Planning

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Specialist Engineer, Station Planning

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Section: **5.4**

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Contributed by:

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Sr. Engineer, Transmission Lines Engineering

[redacted]

Executive Summary

[redacted], the Interconnection Customer (IC), requests to interconnect its [redacted] (2025 CEAP IR #65) to the BC Hydro (BCH) system. [redacted] has thirty (30) [redacted] type-3 wind turbine generators (WTG), adding a total capacity of 204 MW with a maximum power injection of 190.3 MW into the BC Hydro system. The Point of Interconnection (POI) is a 138 kV tap structure on BC Hydro's transmission line 1L363 near BCH's Portage Pass Substation (PPS), approximately 7.0 km to GMS. The [redacted] will be indirectly connected with the BC Hydro transmission system via a future third party-built radial 138 kV line from the POI to a new switching station and the future third party substation (temporarily designated as CNTX and TVC-C), where the wind project will be tapped on the third-party private line next to the CNTX via a new customer-built 45.7 km long 138 kV transmission connection line. The IC's proposed commercial operation date (COD) is October 1, 2029.

This Feasibility Study has identified the following conclusions and requirements to connect [redacted] and its facilities to BCH transmission system at the proposed POI:

1. The proposed indirect interconnection with a POI, a new tap structure on the 138 kV line 1L363 is acceptable to connect [redacted] to the BCH transmission system. The future third party-built line must be in-service and operated to 138 kV before the COD of the [redacted]

   This study assumes that the third-party built line will remain at its initial 138 kV configuration and will not operate at 230 kV before October 1, 2029 and in future. The IC's connection line will be permanently operated at 138 kV from 1L363 and the third-party owned line. If this study assumption changes, the results of this feasibility study will no longer be valid.

2. The connection of the [redacted] causes thermal overload on the 138 kV line 1L363 (Gordon M. Shrum G. S. (GMS) – P65 POI) under system normal conditions. Thermal upgrade of 1L363 line section from GMS to P65 POI, approximately 7 km with a higher ampacity of 850 amperes minimum summer continuous rating is required.

3. Thermal overloads have been identified on the 500 kV lines 5L1, 5L2 and 5L3 under single contingencies involving the of loss of one of the 500 kV lines 5L3, 5L4, or 5L7. These overloads are currently mitigated by the G.M. Shrum Area Gen Shedding remedial action scheme (RAS). The [redacted] is required to participate in the existing Gen Shedding RAS. Further RAS details will be studied under the System Impact Study (SIS) stage.

4. Anti-islanding protection is required for the [redacted] and shall be configured in the manner that does not compromise the required ride-through performance.

5. [redacted] is not allowed for islanded operation with BCH loads. A Direct Transfer Trip (DTT) protection scheme is required to isolate the [redacted] at the IC's entrance circuit breaker to avoid potential islanding operations with the existing and future loads.

6. 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, per BC Hydro's TIR Section 6.4.2. Based on the IC-submitted PSS/E model, the proposed IC's wind project meets the reactive capability requirement above.

7. The "STATCOM option" for the proposed type-3 WTGs is required so that each turbine can provide reactive power capability at zero MW output. It is understood that, due to inherent limitation, type-3 WTGs with "STATCOM option" enabled can provide only partial reactive capability when the turbine is at standstill.

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

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
GMS	Gordan M. Shrum
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
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

Error! Reference source not found. 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)	A tap structure on 1L363	
IC's Proposed COD	October 1, 2029	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	190.3 MW (Summer)	190.3 MW (Winter)
Number of Generator Units	30 x 6.8 MW WTGs	
Plant Fuel	Wind	

[redacted] the Interconnection Customer (IC), requests to interconnect its [redacted] (2025 CEAP IR #65) to the BC Hydro (BCH) system. [redacted] has thirty (30) [redacted] type-3 wind turbine generators (WTG), adding a total capacity of 204 MW with a maximum power injection of 190.3 MW into the BC Hydro system. The Point of Interconnection (POI) is a 138 kV tap structure on BC Hydro's transmission line 1L363 near BCH's Portage Pass Substation (PPS). The [redacted] will be indirectly connected with the BC Hydro transmission system via a future third party-built radial 138 kV line from the POI to a new switching station and the future third party substation (temporarily designated as CNTX and TVC-C), where the wind project will be tapped on the third-party private line next to the CNTX via a new customer-built 45.7 km long 138 kV transmission connection line. The IC's proposed commercial operation date (COD) is October 1, 2029.

Figure 1-1 shows the Peace Region transmission system diagram including IC's wind project (P65) interconnection. The Peace Region transmission system consists of 230 kV and 138 kV transmission infrastructures supplied from Gordon M. Shrum Generating Station (GMS) and South Bank (SBK) substation, which are the major sources of supply to the Peace Region transmission system. Wind power projects such as Bear Mountain Wind, Dokie Wind, Quality Wind, Meikle Wind, Moose Lake Wind, Quality Wind, and Zonnebeke Wind, have been successfully integrated into the Peace Region transmission system.

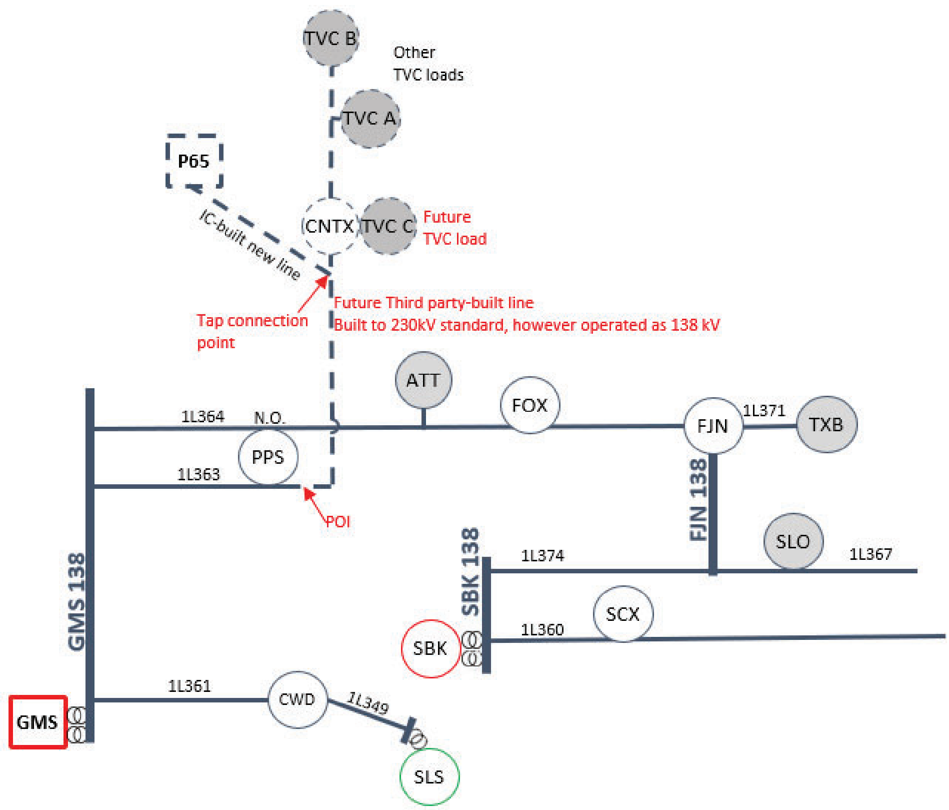

Figure 1-1: Peace Region Transmission System Single Line Diagram.

In addition to the existing generators, there are three future generating projects with higher queue priority in the Peace Region. Two of them — [redacted] and [redacted], with installed capacity of 200 MW each — are [redacted] projects from the 2024 CEAP. Moreover, one wind farm with 56 MW installed capacity will also be added in the Peace 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 the subsequent System Impact Study (SIS) 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 October 14, 2025, for the study purpose. Assumptions are made wherever the IC's input is unavailable. Appendix A shows the schematic diagram of the IC's Project IC's project used in the study model.

The power flow study cases used in this Feasibility Study are established based upon the BC Hydro base resource plan and load forecasts available at the time of performing the study, which includes existing and future generations, 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 2024 Distribution Substation Load Forecast, 2025 Transmission Voltage Customer (TVC) Load Forecast and 2025 System Peak Forecast are used.

2) September 2024 Base Resource Plan.

3) Two successful projects from the [redacted] with installed capacity of 200 MW each, are considered in this study. [redacted] will be in service on September 30, 2031, and [redacted] will be in service on October 1, 2030.

4) A future 56 MW wind generation interconnection in the Peach Region will be in service on October 31, 2028.

5) Fort St. John Transmission Reinforcement project will be in-service in October 2029. This project builds a new 138 kV transmission line from SBK to Taylor substation (TAY).

6) All BCH new TVC loads, and associated system reinforcements are modeled in this study.

7) This study assumes that the third-party owned line will remain at its initial 138 kV configuration and will not operate at 230 kV before October 1, 2029. The IC's connection line will be permanently operated at 138 kV from 1L363 and the third-party owned line. The study will exclude the impacts and the reinforcement needs resulting from the potential 230 kV conversion

of the third-party line. However, BC Hydro's understanding is that the transmission line built and owned by a third party connected to BC Hydro's 1L363, is planned for conversion to 230 kV prior to the proponent's requested COD of October 1, 2029, but this is out of the interconnection study scope.

8) Based on the information provided by IC, the third-party owned transmission line is assumed to have a minimum load of 0 MW.

9) The third-party owned line will have sufficient capacity to accommodate the IC's wind project.

5 System Studies and Results

The [redacted] will be indirectly connected with the BC Hydro transmission system via a future third party-built radial 138 kV line from the POI to CNTX, where the wind project will be tapped on the third-party built line next to the CNTX via a new customer-built 138 kV connection line.

BC Hydro's understanding is that the future transmission line built and owned by a third party connected to BC Hydro's 1L363, is planned for conversion to 230 kV prior to the IC's requested COD of October 1, 2029. This study assumes that the third-party owned line will remain at its initial 138 kV configuration and will not operate at 230 kV before October 1, 2029 and in the future. The IC's connection line will be permanently operated at 138 kV from 1L363 and the third-party owned line. If this assumption changes, the results of this feasibility study will no longer be valid.

BC Hydro was unable to evaluate the impact of the IC's project converting from 138 kV to 230 kV because the interconnection request did not include sufficient information. Such impacts can only be assessed during the SIS stage once additional details and accurate information regarding the third-party system and the timing of the 230 kV conversion are provided.

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 scenarios — 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

Thermal overload on the 138 kV line 1L363 (GMS – P65 POI) is observed under system normal condition (P0). Thermal upgrade of 1L363 line section from GMS to P65 POI, approximately 7 km with a higher ampacity of 850 amperes minimum summer continuous rating is required.

In addition, the interconnection of [redacted] exacerbates the thermal overloads on the 500 kV lines 5L1, 5L2 and 5L3 under single contingencies of loss of one of the 500 kV lines 5L3, 5L4, or 5L7. These overloads are currently mitigated by the G.M. Shrum Area Gen Shedding Remedial Action Scheme (RAS). The [redacted] is required to participate in the existing GMS Area Gen Shedding RAS. Further details of RAS will be studied under the SIS stage. Appendix B shows the summary of the branch loading study results.

5.1.2 Steady-State Voltage Analysis

With the connection of the IC's project, the stead-state voltage performance under system normal condition is acceptable for all the three scenarios (30LS, 30HS, 29HW). Appendix B shows the summary of 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 PSS/E power flow 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.

In addition, according to the IC-provided reactive capability data, the proposed WTG would provide +1.7 MVAr to -1.7 MVAr reactive capability at the zero MW output if the turbine's "STATCOM" function is enabled. This function needs to be re-confirmed if the IC's project proceeds to next stage of the interconnection process.

5.1.4 Anti-Islanding Requirements

[redacted] 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.

[redacted] would be islanded with the TVC loads in the event of no-fault opening 1L363 at GMS, or a 1L363 fault, or a GMS 1CB2 internal breaker fault, or a CNTX internal breaker fault. A Direct Transfer Trip (DTT) protection scheme is required to isolate the IC's wind project at the IC's entrance circuit breaker to avoid potential islanding operations with the planned TVC and existing BCH loads.

5.1.5 Other Performance Requirements

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

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 SIS stage if needed.

5.3 Stations Requirements

The Point of Interconnection (POI) is on BC Hydro's transmission line 1L363 near BCH's Portage Pass Substation (PPS).

No station work is required.

5.4 Transmission Line Requirements

Thermal upgrade of 138 kV line 1L363 (GMS – P65 POI), approximately 7 km, with a higher ampacity of 850 amperes minimum summer rating with conductor change from Merlin" ACSR conductor to "Mica" ACSR. Structure replacements may be required.

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

This Feasibility Study has identified the following conclusions and requirements to connect [redacted] and its facilities to BCH Transmission System at the proposed POI:

1. The proposed indirect interconnection with a POI, a new tap structure on the 138 kV line 1L363 is acceptable to connect [redacted] to the BCH transmission system. The future third party-built line must be in-service and operated to 138 kV before the COD of the [redacted].

   This study assumes that the third-party built line will remain at its initial 138 kV configuration and will not operate at 230 kV before October 1, 2029 and in future. The IC's connection line will be permanently operated at 138 kV from 1L363 and the third-party owned line. If this study assumption changes, the results of this feasibility study will no longer be valid.

2. The connection of the [redacted] causes thermal overload on the 138 kV line 1L363 (Gordon M. Shrum G. S. (GMS) – P65 POI) under system normal conditions. Thermal upgrade of 1L363 line section from GMS to P65 POI, approximately 7 km with a higher ampacity of 850 amperes minimum summer continuous rating is required.

3. Thermal overloads have been identified on the 500 kV lines 5L1, 5L2 and 5L3 under single contingencies involving the of loss of one of the 500 kV lines 5L3, 5L4, or 5L7. These overloads are currently mitigated by the G.M. Shrum Area Gen Shedding remedial action scheme (RAS). The [redacted] is required to participate in the existing Gen Shedding RAS. Further RAS details will be studied under the SIS stage.

4. Anti-islanding protection is required for the [redacted] and shall be configured in the manner that does not compromise the required ride-through performance.

5. [redacted] is not allowed for islanded operation with BCH loads. A Direct Transfer Trip (DTT) protection scheme is required to isolate the [redacted] at the IC's entrance circuit breaker to avoid potential islanding operations with the existing and future loads.

6. 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, per BC Hydro's TIR Section 6.4.2. Based on the IC-submitted PSS/E model, the proposed IC's wind project meets the reactive capability requirement above.

7. The "STATCOM option" for the proposed type-3 WTGs is required so that each turbine can provide reactive power capability at zero MW output. It is understood that, due to inherent limitation, type-3 WTGs with "STATCOM option" enabled can provide only partial reactive capability when the turbine is at standstill.

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

Appendix A
Schematic Diagram of the IC's Project

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

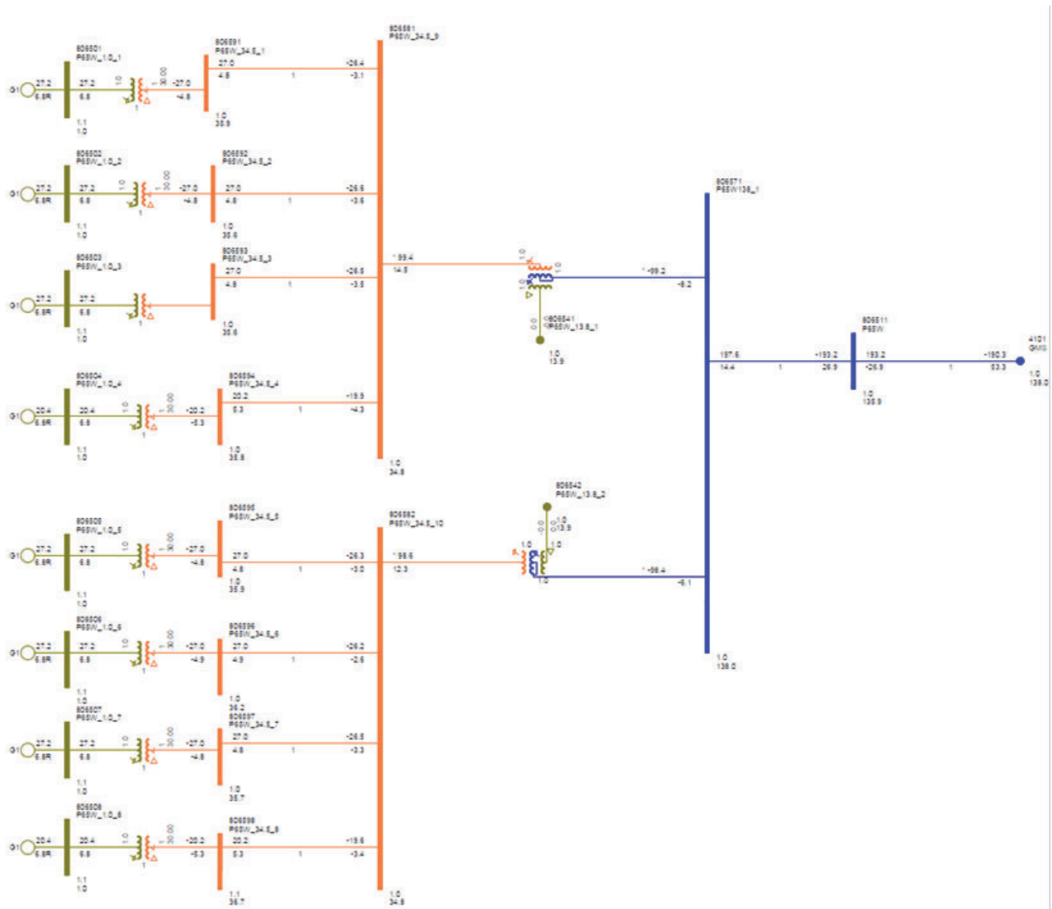

Figure A-1: [redacted] Plant Schematic Diagram.

Appendix B
Power Flow Study Results

Base Scenario (29HW/30HS/30LS)

Table B-1: Thermal Overload Study Results

Case	IC's Generator Output	Contingency		Branch Loading (Amps/MVA)		
				GMS T11 or T12	1L363	1L361
		Cate,	Description	500/138kV (MVA)	GMS-PPS (Amps)	CWD-GMS (Amps)
Winter ratings				287	600	600
29hw	Max	P0	System Normal	74.4 25.9%	814.9 135.8%	57.8 9.6%
		P1	1L361	74.0 25.8%	814.8 135.8%	N/A
		P1	1L364	96.3 33.6%	815.0 135.8%	59.5 9.9%
		P1	GMS T11 or T12	134.0 46.7%	814.9 135.8%	66.3 11.1%
Summer ratings				285	560	588
30hs	Max	P0	System Normal	89.3 31.3%	820.4 146.5%	57.4 9.8%
		P1	1L361	85.8 30.1%	820.2 146.5%	N/A
		P1	1L364	102.0 35.8%	820.4 146.5%	50.1 8.5%
		P1	GMS T11 or T12	158.3 55.5%	820.3 146.5%	48.3 8.2%
30ls	Max	P0	System Normal	96.6 33.9%	821.4 146.7%	75.5 12.8%
		P1	1L361	90.2 31.6%	821.2 146.6%	N/A
		P1	1L364	106.0 37.2%	821.4 146.7%	68.1 11.6%
		P1	GMS T11 or T12	170.7 59.9%	821.3 146.7%	49.4 8.4%

Table B-2: Steady-State Voltage Study Results

Case	IC's Generator Output	Contingency		Bus Voltage (PU)		
		Cate.	Description	PPS 364P 138	GMS 138	CWD 1B1 138
29hw	Max	P0	System Normal	1.018	1.021	1.001
		P1	1L364	N/A	1.020	1.000
		P1	GMS T11 or T12	1.019	1.023	1.000
30hs	Max	P0	System Normal	1.018	1.020	1.006
		P1	1L364	N/A	1.020	1.005
		P1	GMS T11 or T12	1.020	1.022	1.005
30ls	Max	P0	System Normal	1.019	1.021	1.009
		P1	1L364	N/A	1.020	1.009
		P1	GMS T11 or T12	1.019	1.021	1.007