BC Hydro
Power smart

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

November 24, 2025

[redacted]

via email: [redacted]

<u>RE: CEAP IR #8 – [redacted] – Interconnection Feasibility Study</u>

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 $151.6 M.

Major Scope of Work Identified:

- Expand the substation and extend the existing 287kV bus structure, and add one 287 kV line position with associated substation equipment at BC Hydro Tatogga substation (TAT)
- Terminate the Interconnection Customer's transmission line at TAT
- Upgrade series capacitors at BC Hydro Bob Quinn (BQN) substation
- Upgrade required substation facilities, infrastructures, and bus work to support new station(s) equipment
- Supply and install required Protection, Control and Telecommunications equipment

Exclusions:

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

Key Assumptions:

- Construction by contractor
- 24 months of construction is considered
- No construction during winter season
- Execution of early Engineering and Procurement Agreement
- No expansion of existing stations or 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 4 2032 (calendar year). To achieve this timeline, we may need to expedite certain activities, including engineering design and procurement of long-lead equipment.

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

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

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

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

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

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

Sincerely,

[redacted]

[redacted]

Manager, Customer Interconnections

BC Hydro

Encl.: CEAP_2025_IR8_[redacted]Feasibility_Study.pdf

BC Hydro
Power smart

[redacted]

Interconnection Feasibility Study

BC Hydro EGBC Permit to Practice No: 1002449

2025 CEAP IR # 8

Prepared for: [redacted]

Prepared by: [redacted]

[redacted]
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Reviewed by: [redacted]

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Engineering Team Lead, Planning Coordinator & Bulk Planning

Accepted by: [redacted]

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Manager, Transmission Planning

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Prepared for:	[redacted]
Prepared by:	[redacted]
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Reviewed by:	[redacted]
Title:	Engineering Team Lead, Planning Coordinator & Bulk Planning
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	Manager, Transmission Planning
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Revision	Date	Description
0	2025 Nov	Initial release

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Planning Coordinator & Bulk Planning

Section: **5.2, 5.3**

Discipline: Stations Planning

Contributed by:

[redacted] [redacted]

[redacted]

Sr. Engineer, Substations Growth & Sustainment

Executive Summary

[redacted], the interconnection customer (IC), requests to interconnect its [redacted] Project to the BC Hydro system. [redacted] has sixty (60) [redacted] type-3 wind turbine generators, adding a total capacity of 420 MW into the BC Hydro system. The Point of Interconnection (POI) is on BC Hydro's 287 kV bus in Tatogga (TAT) Substation. The IC's project will connect to the POI via a 33.3 km 287 kV interconnection line. The IC's proposed commercial operation date (COD) is December 31st, 2032.

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

1. Feasibility study indicates that connecting the plant to a 287kV bus at TAT is acceptable after system reinforcement requirements as shown below.
2. Facility rating upgrade of Bob Quinn substation (BQN) series capacitors to 1,300 Amps is required to mitigate the overload during normal operation after the connection of [redacted] plant. Series capacitor protection devices, for example, Metal Oxide Varistors (MOV) may need to be upgraded due to rating change.
3. The study did not find any voltage performance violation or voltage stability concern under system normal, caused by connection of [redacted]
4. Voltage stability issue on the BC Hydro lines 2L102 and the future 2L377 appear under single contingencies (BQN Series Capacitor Bypass) after the connection of [redacted]. In addition, Skeena 500kV/287kV transformers will overload during circuit breaker failures or stuck breaker conditions. The new wind generators at [redacted] are required to participate in the existing North Coast generator shedding RAS to address those voltage stability concerns.
5. Anti-islanding protection is required for the [redacted] and shall be configured in the manner that does not compromise the required ride-through performance.

6. The proposed [redacted] is required to have the dynamic reactive power capability at a minimum of +/- 33% of its MPO from the plants at the high-voltage side of the 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 [redacted] meets the reactive capability requirement above.

7. The "reactive power at zero output" mode, such as "STATCOM option", is required so that each turbine invertor can provide reactive power capability at zero MW output.

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

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
BQN	Bob Quinn Switching Station
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
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
TAT	Tattoga Switching Station
TIR	BC Hydro “60 KV to 500 kV Technical Interconnection Requirements for Power Generators”
WECC	Western Electricity Coordinating Council
WTG	Wind Turbine Generator
EDM	Edmonds Office
FVO	Fraser Valley Office
SIC	South Interior Control
SIO	South Interior Office

1 Introduction

The project reviewed in this feasibility study is as described in Table 1 below.

Table 1-1: Summary Project Information

Project Name	[redacted]	
Proponent Name	[redacted]	
Point of Interconnection	Tatogga Substation 287kV	
Applicant Proposed COD	31 December 2032	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum injection at POI (MW)	394 (Summer)	394 (Winter)
Total installed capacity (MW)	420 (Summer)	420 (Winter)
Number of Generator Units	60 x 7 MW	
Plant Fuel	Wind	

[redacted], the interconnection customer (IC), requests to interconnect its [redacted] to the BC Hydro system. [redacted] Wind Project has sixty (60) [redacted] type-3 wind turbine generators, adding a total capacity of 420 MW into the BC Hydro system. The Point of Interconnection (POI) is on BC Hydro's 287 kV bus in Tatogga Substation. The proposed commercial operation date (COD) is December 31st, 2032.

Figure 1-1 shows the Bob Quinn region 287/138 kV transmission system diagram. The interconnection point of TAT 287 kV is fed from Bob Quinn (BQN) substation which is connected to Skeena (SKA) substation through Treaty Creek (TCT) substation. SKA substation is connected to the 500kV system. Customer's system topology behind the Point of Interconnection is provided in the Appendix, Figure 1-1.

The line between BQN and TCT has a series capacitor installed at BQN to increase transfer capability. The continuous facility rating of the BQN series capacitor 5CX1 is 323 MVA (650A).

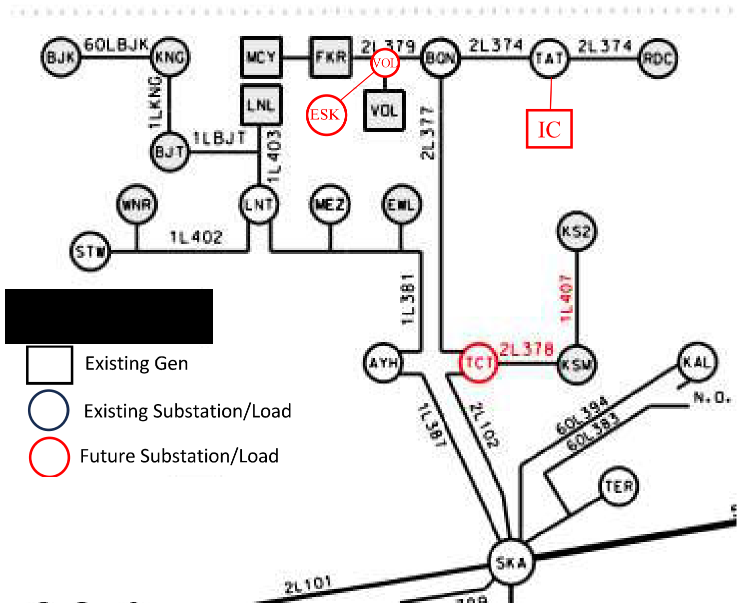

Figure 1-1: Bob Quinn region 287/138 kV Transmission System Diagram

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 Categories P0, P1, and P2 planning events as defined in TPL-001-4 Table 1 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 would 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 be addressed in subsequent detailed and coordinated studies with the relevant adjacent entities if the proposed interconnection proceeds further.

Please note that, due to the compressed study timeline for 2025 CEAP 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.
- 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, October 7, 2025.

4 Assumptions and Conditions

The study is performed based on the customer's study data form submitted on or before the CEAP IR submission date, which is Oct 14, 2025. Assumptions are made wherever the customer's input is not available. Appendix A shows the plant single line diagram for the 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 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 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. Use of the latest August 2025 distribution load forecast, reference system coincident forecast and reference TVC.
3. Planned transmission reinforcement projects in the study area.
    - Prince George to Terrace series Capacitor project to be installed in existing lines 5L61, 5L62 and 5L63.
    - New 500kV lines PGGT: 5L64, GTTT: 5L65& 5L66 (WSN to SKA).
    - Other system reinforcements in the regional system triggered by future customers are also included in the study model.

5 System Studies and Results

Based upon the IC's submitted information and the area system conditions, expansion of the existing substation Tatogga (TAT) within the limits of the current property boundaries, as the proposed POI and reinforcement at Bob Quinn substation are required to interconnect the IC's generating project to the BCH system. Details of the study results and reinforcement scopes are provided in the subsections below.

5.1 Power Flow Study Results

Steady-state power flow studies have been conducted with the focus on the 33LS system condition, taking into considerations the COD of this Wind Project and factors such as load conditions, seasonal variation in ambient temperatures, and generation patterns that stress the transmission system. The 32HW and 33HS cases are also checked to capture any performance violations over other seasons following the ISD.

The studies are performed under system normal conditions and after critical system contingencies in this area as 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 (32HW, 33HS, 33LS), there is an overload identified under system normal condition (P0) on the BQN series capacitor. Facility rating upgrade of BQN series capacitors is required to integrate the [redacted] plant.

The study found potential thermal overload in 2033 heavy and low summer on 500/287 kV SKA transformers under SKA 5CB3 or 5CB23 internal breaker fault or stuck breaker events. A Remedial Action Scheme (RAS) to curtail [redacted] plant is required upon its COD to mitigate this overload. BC Hydro will develop the details of the RAS to address system constraints due to the multiple contingencies at the next study stage.

Table 5-1 provides summary of branch overloads observed in the study. Detail power flow study results are provided in Appendix B, Table B-1.

Table 5-1: Summary of Branch Loading Analysis Results

Case	Contingency Identified		Branch Loading		
	Cate-gory	Description	Branch	Load MVA	Loading%
32HW	P0	System Normal	BQN SC	534.5	165.4
33HS	P0	System Normal	BQN SC	559.6	173.2
	P2/P4	Fault at SKA 5CB3 or (fault at SKA T1 or T2 w stuck 5CB3), tripping SKA T1, T2 & 5CX1	SKA T3	673.1	100.2
33LS	P0	System Normal	BQN SC	620.2	191.9
	P2/P4	Fault at SKA 5CB3 or (fault at SKA T1 or T2 w stuck breaker), tripping SKA T1, T2 & 5CX1	SKA T3	760.3	113.1
		Fault at SKA 5CB23 or (Fault at SKA T2 or T3 w stuck 5CB23), tripping SKA T2, T3 & 5CX2	SKA T1	744.0	111

5.1.2 Steady-State Voltage Analysis

For all the studied load conditions (32HW, 33HS, 33LS), the voltage performance under system normal condition (P0) is acceptable.

The study finds [redacted] causes voltage stability issues when series capacitor BQN bypass occurs. Table 5-2 provides summary of voltage performance violations observed in the study. Detail steady-state voltage performance results are provided in Appendix B, Table B-2.

A RAS is required to shed generation in the event of a bypass of BQN series capacitor and address instantaneous voltage collapse between SKA and BQN on that event. Detailed dynamic simulation will be performed in next phase of the project to further investigate this issue and develop the RAS specifications.

Table 5-2: Summary of Steady-State Voltage Performance Violations

Case	IPP's Gen Output (MW)	Contingency		Bus Voltage (PU)			
		Cat.	Description	TAT 287	BQN 287	TCT 287	MIN 287
		P1	Bypass on BQN Series Capacitor	0.99	0.92	0.88	0.99
		P1	Bypass on BQN Series Capacitor	*	*	*	*

*Voltage collapse, no meaningful voltage values available for these buses.

5.1.3 Reactive Power Capability Evaluation

The BCH TIR requires IBR generators have the dynamic reactive power capability at a minimum of +/- 33% of its Maximum Power Output (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 for this project, the study finds that the proposed generating project can meet the BC Hydro's reactive capability requirement.

In addition, according to the IC-provided reactive capability data, the proposed WTG would provide +/- 3 MVAr reactive capability at the zero MW output and 1.0 p.u. terminal voltage if the turbine's "STATCOM" function is enabled. This function needs to be re-confirmed if the IC's project proceeds to next stage of the call process.

5.1.4 Anti-Islanding Requirements

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

5.1.5 Other Performance Requirements

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

5.2 Fault Analysis

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

5.3 Stations Requirements

The Point of Interconnection (POI) is at the 287 kV bus of BC Hydro 287 kV Tatogga Substation (TAT) via a customer built 287 kV line.

To interconnect the IC, the following is the station work required at TAT and BQN substations, respectively.

TAT Substation:

- Expand the substation and extend the existing 287 kV bus structure within the limits of the current property boundaries.
- Add one 287kV line position with the associated substation equipment. Refer to the one-line diagram in the Appendix C, Figure C-1 for further details.
- Terminate the [redacted] ustomer line.
- Other associated station work, e.g. civil work, cable running, grounding, connections, etc.

BQN Substation

- Replace the existing 2CX1 series capacitor bank with a new unit rated for a minimum current capacity of 1,300 A.
- Equipment engineers will assess the feasibility of upgrading the 2CX1 series capacitor bank in the next stage of the project.
- An online diagram will not be provided at this stage of the study.

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. Feasibility study indicates that connecting the plant to a 287kV bus at TAT is acceptable after system reinforcement requirements as shown below.
2. Thermal upgrade of BQN series capacitors to 1,267 Amps is required to mitigate the overload during normal operation after the connection of [redacted] plant. Series capacitor protection devices, for example, Metal Oxide Varistors (MOV) may need to be upgraded due to rating change.
3. No voltage performance violations or voltage stability concerns were identified under normal system conditions due to the [redacted]. However, voltage stability issues were observed on BC Hydro lines 2L102 and the future 2L377 under single contingency scenarios (e.g., Bob Quinn Series Capacitor Bypass). Additionally, the Skeena 500kV/287kV transformers are expected to overload during circuit breaker failure or stuck breaker conditions.
4. The new wind generators at [redacted] are required to participate in the existing North Coast generator shedding RAS to address voltage stability concerns and facility overloads during contingencies.
5. Anti-islanding protection is required for the [redacted] and shall be configured in the manner that does not compromise the required ride-through performance.
6. The proposed [redacted] is required to have the dynamic reactive power capability at a minimum of +/- 33% of its MPO from the plants at the high-voltage side of the 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 [redacted] meets the reactive capability requirement above.

7. The “reactive power at zero output” mode, such as “STATCOM option”, is required so that each turbine or solar invertor can provide reactive power capability at zero MW output.
8. Station work at the Tatogga Substation include expansion of the 287 kV bus to add a new line position and associated equipment for terminating the [redacted] customer line.
9. Station work at the Bob Quinn Substation include replacing the series capacitor bank 2CX1 with a new unit rated for at least 1,300 A. Equipment engineers will evaluate upgrade feasibility in the next project phase.

Appendix A

Schematic Diagram of the IC’s Project

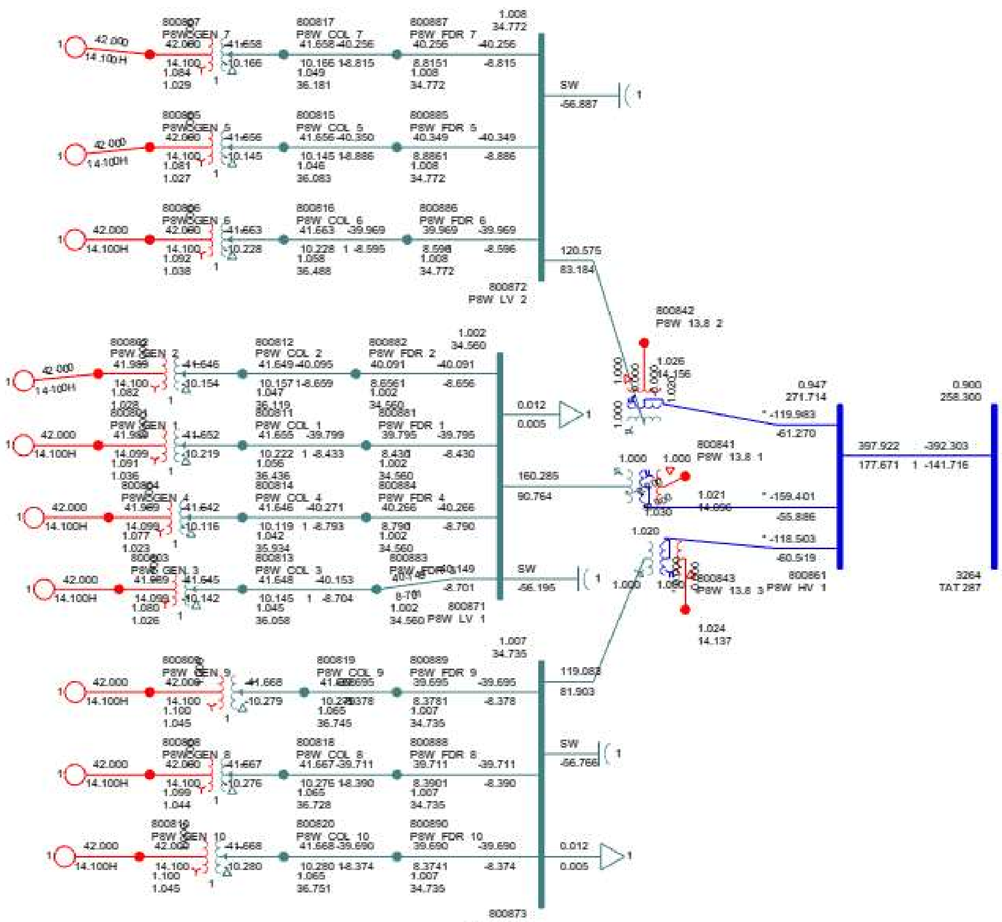

Figure A-1: [redacted] Plant Single Line Diagram

Appendix B
Power Flow Study Results

Power flow study results for study years 32HW, 33HS and 33LS are provided below.

Table B-1: Branch Loading Study Results

Case	Contingency Identified		Branch Loading		
	Cate-gory	Description	Branch	Load MVA	Loading%
32HW	P0	System Normal	BQN SC	552.2	170.9
			2L377	552.2	75.2
			2L102	530.4	72.2
			2L374	284.7	47.7
33HS	P0	System Normal	BQN SC	580.5	179.7
			2L377	580.5	79.07
			2L102	559.6	76.2
			2L374	308.0	51.6
	P2/P4	Fault at SKA 5CB3 or (fault at SKA T1 or T2 w stuck 5CB3), tripping SKA T1, T2 & 5CX1	SKA T3	673.1	100.2
		Fault at SKA 5CB23 or (Fault at SKA T2 or T3 w stuck 5CB23), tripping SKA T2, T3 & 5CX2	SKA T1	654.5	97.4
33LS	P0	System Normal	BQN SC	650.7	201.4
			2L377	650.7	88.6
			2L102	622.8	84.8
			2L374	360.3	60.4
	P2/P4	Fault at SKA 5CB3 or (fault at SKA T1 or T2 w stuck breaker), tripping SKA T1, T2 & 5CX1	SKA T3	760.3	113.1
		Fault at SKA 5CB23 or (Fault at SKA T2 or T3 w stuck 5CB23), tripping SKA T2, T3 & 5CX2	SKA T1	744.0	111

Table B-2: Steady-State Voltage Study Results

Case	IPP's Gen Output (MW)	Contingency		Bus Voltage (PU)					
		Cat.	Description	TAT 287	BQN 287	TCT 287	MIN 287	SKA 287	SKA 500
32HW	420	P0	System Normal	1.01	1.00	1.00	0.99	1.01	1.04
		P1	Bypass on BQN Series Capacitor	0.99	0.95	0.92	0.99	1.00	1.03
			2L103 OOS	1.01	1.00	1.00	0.99	1.01	1.05
			RDC OOS	1.01	0.99	0.99	0.99	1.00	1.04
		P2/P4	Fault at SKA 5CB3 or (fault at SKA T1 or T2 w stuck breaker), tripping SKA T1, T2 & 5CX1	1.01	1.00	1.00	0.99	1.01	1.04
33HS	420	P0	System Normal	1.01	1.00	1.00	0.99	1.00	1.05
		P1	Bypass on BQN Series Capacitor	0.99	0.92	0.88	0.99	1.00	1.04
			2L103 OOS	1.01	1.00	1.00	0.99	1.01	1.04
			RDC OOS	1,01	1.00	0.99	0.99	1.00	1.05
		P2/P4	Fault at SKA 5CB3 or (fault at SKA T1 or T2 w stuck breaker), tripping SKA T1, T2 & 5CX1	1.01	1.00	1.00	0.99	1.00	1.05
33LS	420	P0	System Normal	1.01	0.99	0.99	0.99	1.00	1.04
		P1	Bypass on BQN Series Capacitor	*	*	*	*	*	*
			2L103 OOS	1.01	0.99	0.99	0.99	1.00	1.04
			RDC OOS	1.01	0.99	0.99	0.99	1.00	1.04
		P2/P4	Fault at SKA 5CB3 or (fault at SKA T1 or T2 w stuck breaker), tripping SKA T1, T2 & 5CX1	1.01	0.99	0.99	0.99	1.00	1.04

Appendix C
One-Line Sketch for Tatogga Substation Expansion

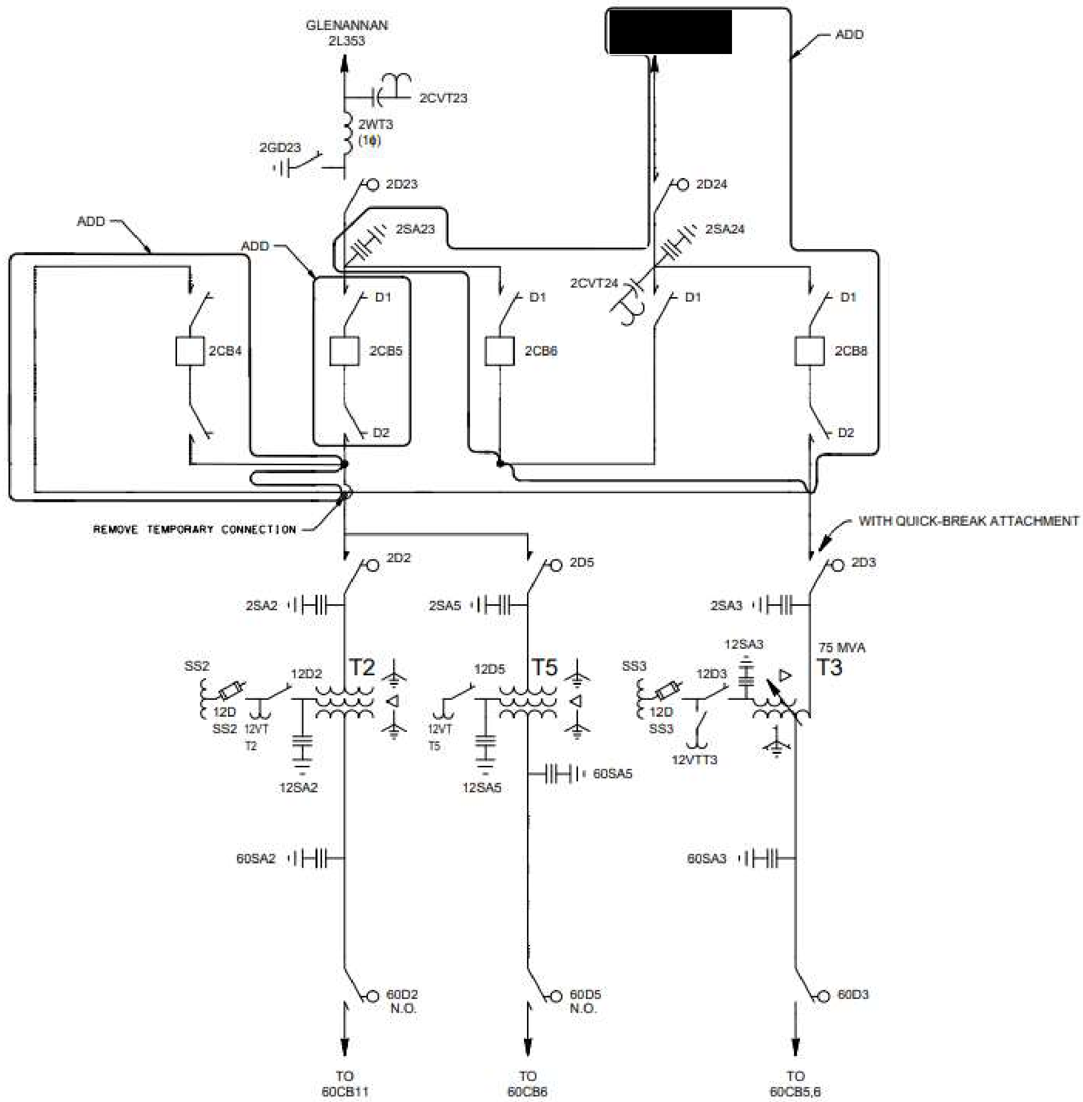

Figure C-1: Stations Planning One-Line Sketch for the Expansion of Tatogga Switching Station.