BC Hydro
Power smart

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

November 24, 2025

[redacted]

via email: [redacted]

RE: CEAP IR #63 – [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 $215.5 M.

Major Scope of Work Identified:

- Install a 600 MVA 230 kV phase shifting transformer on 2L312 at the 230 kV Sundance Lakes substation (SLS) with bypass facilities
- At the proposed East Groundbirch switching station (EGB), add three, new 230 kV circuit breakers 2CB1, 2CB2 and 2CB5 with associated disconnects to expand the 230 kV three-circuit breaker ring bus to a six-circuit breaker ring bus to terminate [redacted] line and loop in 2L329

- Add three, 230 kV line terminals with associated disconnect, surge arrester, capacitor voltage transformer
- Terminate 230 kV lines 2L329-A, 2L329-B and 2L329-C to the individual line terminals.
- Complete other associated station works for the above changes
- Expand the control building, if required, to accommodate new P&C panels and other equipment
- Expand the existing 230 kV switchyard within the current property line to accommodate the above additional facilities
- Supply and install required Protection, Control and Telecommunications equipment

Exclusions:

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

Key Assumptions:

- Construction by contractor
- 24 months of construction is considered
- No construction during winter season
- Execution of early Engineering and Procurement Agreement
- EGB in-service
- Ability to expand EGB
- Site expansion of 71 m × 143 m is assumed to accommodate the new line position at EGB
- A site expansion of 50 m × 60 m at SLS is assumed to accommodate the new equipment
- Additional property is required for SLS expansion
- No expansion of existing control buildings to accommodate new equipment
- Impact Benefit Agreements with First Nations are not considered

Key Risks:

- Cost and ability to expand EGB may be higher than estimated which may increase the Network Upgrade cost estimate and schedule
- Potential [redacted] issues limiting the expansion at EGB
- Expansion of the existing control building may be required leading to increased costs and/or a longer project schedule
- Major equipment delivery presents potential project cost and schedule risks, based on variance in equipment lead times
- No defined supply chain strategy; construction costs may increase depending on delivery method
- Project schedule may be longer than expected, leading to increased overhead costs
- Ground improvements may be required leading to increased construction costs
- Contaminated soil may be encountered leading to increased construction costs
- Cost of materials and major equipment may be affected by market conditions and escalation

Study Limitations and Exclusions

Protection, Control, and Telecommunications

The Interconnection Feasibility Study does not include a detailed review of the protection, control, and telecommunications system requirements specific to your Interconnection Request. Based on a high-level review, we have identified proxy costs for protection, control, and telecom Network Upgrades drawn from comparable interconnection projects with similar scope and complexity; these proxy costs have been included solely for indicative budgeting purposes. The relative interconnection cost determined by the Interconnection Feasibility Study includes a telecommunications component based on an assumed solution to deliver teleprotection and telecontrol circuit requirements necessary for the Interconnection Request. Protection, control, and telecommunications system requirements will be reviewed in detail in the System Impact Study if you are a successful participant of the CEAP and meet applicable requirements.

For Interconnection Feasibility Study purposes, it is assumed that any applicant-proposed works that could obstruct or impair the performance of existing BC Hydro microwave systems or new links from the proposed Interconnection Customer Interconnection Facilities (ICIF) to the BC Hydro microwave system would be identified and either relocated or repositioned as determined in a System Impact Study if you are a successful participant of the CEAP and meet applicable requirements. Such works may include, but are not limited to, towers, turbines, dams, support structures, panels, surface materials deposited or redistributed, water surface changes, or vegetation.

Generation Shedding/Curtailment Scheme and Electromagnetic Transient (EMT) Studies

The generation shedding/curtailment scheme reviews (e.g., Remedial Action Scheme (RAS), and a direct transfer trip for anti-islanding scheme) and EMT studies are completed in a System Impact Study. The outcomes of these studies may result in additional requirements, which could include Network Upgrades or ICIF. Any costs associated with completion of these studies, and resulting requirements, are not included in the Interconnection Feasibility Study cost estimate.

Revenue Metering

Please note that revenue metering requirements have not been determined with the Interconnection Feasibility Study. As such, any costs associated with revenue metering and other interconnection components are not included in the cost estimate provided above. Once these requirements are defined, costs that are attributable to the Interconnection Customer are to be paid in cash. For more details on revenue metering requirements and responsibilities, please refer to:

https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/distribution/standards/ds-rmr-complex-revenue-metering.pdf.

Schedule

Based on the Interconnection Feasibility Study, the non-binding good faith estimated in-service date for your Interconnection Request's Network Upgrades is Quarter 3 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

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_IR63_[redacted]_Feasibility_Study.pdf

[redacted]

Interconnection Feasibility Study

BC Hydro EGBC Permit to Practice No: 1002449

2025 CEAP IR #63

Prepared for: [redacted]

Prepared by: [redacted]

[redacted]

Specialist Engineer, Transmission Planning

[redacted]

Reviewed by: [redacted]

[redacted]

Technical Strategic Principle, Transmission Planning

Accepted by: [redacted]

Division Manager, Transmission Planning

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0	2025 Nov	Initial release

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5.2, 5.3	Stations Planning

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Executive Summary

[redacted], the interconnection customer (IC), requests to interconnect its [redacted] (2025 CEAP IR #63) to the BC Hydro (BCH) system. [redacted] has forty-five (45) [redacted] type-3 wind turbine generators (WTG), adding a total installed capacity of 306 MW with a maximum power injection of 298 MW into the BCH system. The IC has proposed to connect their wind project to BCH transmission system at the Point of Interconnection (POI), a tap structure located at approximately 19.5 km from the Shell Groundbirch Substation (SGB) on BC Hydro's 230 kV line 2L329 which runs between SGB and Bear Mountain Terminal Station (BMT).

The IC's wind project will be connected via a new 230 kV, approximately 6.9 km, customer-built transmission line (temporarily designated as 2L329-C) from the POI.

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, a tap structure on the 230 kV line 2L329 with tap connection is not acceptable to interconnect the customer's generating project to the BCH system. Instead, it is recommended that the POI be changed to the 230 kV bus of the planned East Groundbirch (EGB) switching station, which is required to loop in the line 2L329 and is located approximately 5 km from the IC proposed POI. The EGB switching station is being built by looping in the existing line 2L333 to support a TVC interconnection request and is currently in the facility study phase.

   Three new 230 kV line positions at EGB are required to loop in 2L329 and to interconnect the proposed [redacted].

2. Thermal overload on the 230 kV line 2L308 is observed during summer light load period under system normal condition (P0). The proposed solution is to install one 600 MVA, 230 kV phase shifting transformer with bypass facilities on line 2L312 at the 230 kV Sundance Lakes Substation (SLS).

3. With the connection of [redacted], the following thermal overloads have been identified under single contingency conditions:

   - 2L392 thermal overload under the single contingency of loss of 2L308 (P1).
   - 2L308 thermal overloads under the single contingency of loss of 2L392-A or SBK_2CB21 (or 2CB22) breaker internal fault (P2).
   - Gordon M. Shrum G.S. (GMS) 500/230 kV transformers T13 or T14 overloads under single contingencies of loss of GMS 500/230 kV T14 or T13 or internal breaker failure GMS-1CB4 or 1CB5, 1CB7.

     The [redacted] is required to participate in and modify the existing Peace Area Wind Farm Gen Shedding Remedial Action Scheme (RAS).

   - Thermal overloads on 500 kV lines 5L1, 5L2 and 5L3 under single contingencies loss of one of 500 kV line, 5L3, 5L4, or 5L7.

     The [redacted] farm is required to participate in the G.M. Shrum Area Gen Shedding RAS.

   Further details of the RAS will be studied under System impact study (SIS) stage.

4. The [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.

5. 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 existing or future loads.

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. Based on the IC-submitted PSS/E model, the proposed [redacted] project does not meet the reactive capability requirement above. It requires an additional 1.27 MVAr capacitive reactive power.

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. BC Hydro recognizes that Type-3 WTGs with the STATCOM option have an

inherent limitation—providing only partial reactive power capability during turbine standstill.

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

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
BMT	Bear Mountain Terminal
CEAP	Competitive Electricity Acquisition Process
COD	Commercial Operation Date
DTT	Direct Transfer Trip
DAW	Dawson Creek Substation
EGB	East Groundbirch
ERIS	Energy Resource Interconnection Service
IBR	Inverter-Based Resources
IC	Interconnection Customer
IR	Interconnection Request
GMS	Gordon M. Shrum G.S.
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
PRES	Peace Region Electric Supply
RAS	Remedial Action Scheme
SGB	Shell Groundbirch Substation
SBK	South Bank Substation
SLS	Sundance Lakes Substation
TIR	BC Hydro “60 KV to 500 kV Technical Interconnection Requirements for Power Generators”
[redacted]	[redacted]
VIC	Virtual Inertia Control
WECC	Western Electricity Coordinating Council
WTG	Wind Turbine Generator

1 Introduction

Table 1-1 below summarizes the project reviewed in this Feasibility Study.

Table 1-1 Summary of Project Information

Project Name	[redacted]	
Name of Interconnection Customer (IC)	[redacted]	
Point of Interconnection (POI)	On the 230 kV line 2L329	
IC's Proposed COD	October 1, 2029	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	298.0 MW (Summer)	298.0 MW (Winter)
Number of Turbines	45 x 6.8 MW WTGs	
Plant Fuel	Wind	

[redacted] the interconnection customer (IC), requests to interconnect its [redacted] (2025 CEAP IR # 63) to the BC Hydro (BCH) system. [redacted] has forty-five (45) [redacted] type-3 wind turbine generators (WTG), adding a total installed capacity of 306 MW with a maximum power injection of 298.0 MW into the BC Hydro system. The IC has proposed to connect their wind project to BCH transmission system at the Point of Interconnection (POI), a tap structure located at approximately 19.5 km from the Shell Groundbirch substation (SGB) on the BC Hydro's 230 kV line 2L329. The [redacted] will be interconnected with the BCH transmission system at the POI via an approximately 6.9 km customer-built 230 kV line. The IC's proposed commercial operation date (COD) is October 1, 2029.

The proposed POI, a tap structure on the 230 kV line 2L329 is not acceptable to interconnect the customer's generating project to the BCH system. Instead, it is recommended that the POI be changed to the 230 kV bus of the planned East Groundbirch (EGB) switching station, which is required to loop in the line 2L329 and is located approximately 14 km from the SGB and 5 km from the IC proposed POI. The EGB switching station is being built by looping in the existing line 2L333 to support a TVC interconnection request and is currently in the construction phase. With the switching station EGB, the existing line 2L333 and 2L329 will be segregated into four new circuits, referred to as: 2L333 (SGB-EGB), 2L334 (EGB-

Bear Mountain Terminal station (BMT)), 2L329-A (SGB-EGB) and 2L329-B (EGB-BMT).

The Peace Region transmission system consists of 230 kV and 138 kV transmission infrastructures supplied from Gordon M. Shrum G.S.(GMS) and South Bank substation, which are the major sources of supply to the Peace Region transmission system. Figure 1-1 shows the Peace region transmission system diagram.

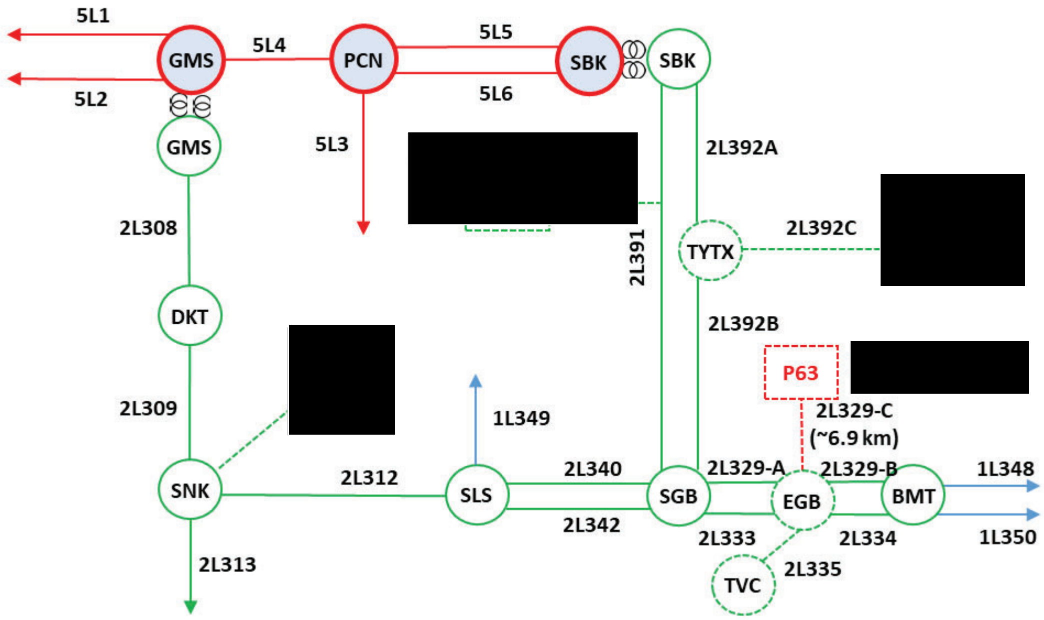


Figure 1-1: Peace Region Transmission System Diagram

2 Purpose and Scopes of Study

This Feasibility Study is a preliminary evaluation of the system impact of interconnecting the proposed project to the BCH 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 BCH 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 (SIS) if the project proceeds further. In addition, any potential impacts to the adjacent external systems to BCH 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 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 BCH 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 used in the study model.

The power flow study cases used in this Feasibility Study are established based upon the BCH 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 Peace region 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 Maximum Power Outputs (MPO) unless otherwise specified.
2) The 2024 Distribution Substation Load Forecast, 2025 Transmission Voltage Customer (TVC) Load Forecast and 2025 System Peak Forecast are used.
3) September 2024 Base Resource Plan.
4) 200 MW [redacted] will be in service on September 30, 2031, and 200 MW [redacted] will be in service on October 1, 2030.
5) A new 56 MW generation interconnection project will be in service on October 31, 2028.
6) 29HW, 30LS, 32HS, and 32LS are used as base case in the study to evaluate system impact after [redacted] project plant interconnection.
7) The Bear Mountain Terminal T4 will be in service by March 2027.
8) 1L377 is normally open between [redacted] Parkland Substation (PLD) and [redacted] Tower 03/07 Substation (ET3).
9) All new TVC load interconnection and associated system reinforcements are modeled in this study.

5 System Studies and Results

Based upon the IC's submitted information and the area system conditions, it is recommended that the proposed POI be changed to the switching station EGB, which is currently under construction, on 230 kV line 2L333. This connection is necessary to ensure system reliability and provide adequate protection performance for the new generation interconnection while continuing to serve existing customers.

Three new 230 kV line positions at EGB are required to loop in 2L329 and to interconnect the proposed [redacted].

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/32LS/32HS system conditions that includes all the higher-queued generating projects ([redacted], [redacted] and a new queue generation project) in the Peace 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 were 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 on the 230 kV line 2L308 between GMS and Dokie Terminal Station (DKT) is observed during light load period under system normal condition (P0). The required system reinforcement to mitigate this thermal overload is to install one 600 MVA 230 kV phase shifting transformer on 2L312 at the 230 kV Sundance Lakes substation (SLS) with bypass facilities. A tap changer controller for the phase shifting transformer is expected to regulate MW flow on the 2L312 and 2L308. The equipment spare strategy for the phase shifting transformer could not result in the lead time to return operation from the potential outages greater than 1 year.

With the connection of [redacted], the following thermal overloads have been identified under single contingencies:

- 2L392 overload under the single contingency of loss of 2L308 (P1).
- 2L308 overloads under the single contingency of loss of 2L392-A (SGB-TYTX) or SBK_2CB21 (or 2CB22) breaker internal fault (P2).
- GMS 500/230 kV transformer T13 or T14 overloads under single contingencies of loss of GMS 500/230 kV T14 or T13 or internal breaker fault GMS-1CB4 (or 1CB5, 1CB7).

  The [redacted] is required to participate in and modify the existing Peace Area Wind Farm Gen Shedding Remedial Action Scheme (RAS).
- Thermal overloads of 500 kV lines 5L1, 5L2 and 5L3 under single contingencies loss of one of 500 kV line, 5L3, 5L4, or 5L7. These existing overloads are currently mitigated by the G.M. Shrum Area Gen Shedding RAS. [redacted] is required to participate in the G.M. Shrum Area Gen Shedding RAS.

The detailed RAS requirements will be confirmed during the SIS stage, if necessary.

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

5.1.2 Steady-State Voltage Analysis

With the connection of the IC’s project, the steady-state voltage performance under system normal and single contingency conditions is acceptable for all the study scenarios (29HW, 30LS, 32LS, and 32HS). 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] cannot meet the BCH's reactive capability requirement at the plant's maximum MW output. It requires additional 1.27 MVAr capacitive reactive power. This 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 -1.9 MVAr reactive capability at the zero MW output if the turbine's "STATCOM" function is enabled. This function needs to be re-confirmed if the IC's project proceeds to next stage of the 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 loads' forms.

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 existing or future 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 wind turbine generators, when equipped with the VIC option, are expected to temporarily boost the MW output to limit the system frequency drop during a major frequency event. The VIC settings should be determined in coordination with BC Hydro in the later stage of the interconnection process.

5.2 Fault Analysis

The short circuit analysis in the Feasibility Study is based upon the latest BCH 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

This study recommends that the POI be changed to the 230 kV bus of the planned EGB switching station, which is required to loop in the line 2L329 and is located approximately 14 km from the SGB.

The scope of work at EGB station includes:

- Add three, new 230 kV circuit breakers 2CB1, 2CB2 and 2CB5 with associated disconnects to expand the 230 kV three-circuit breaker ring bus to a six-circuit breaker ring bus.
- Add three, 230 kV line terminals with associated disconnect, surge arrester, capacitor voltage transformer.
- Terminate 230 kV lines 2L329-A, 2L329-B and 2L329-C to the individual line terminals. Detailed scope will be confirmed during the System Impact Study (SIS) stage, if necessary.
- Complete other associated station works for the above changes.
- Expand the control building, if required, to accommodate new P&C panels and other equipment.
- Expand the existing 230 kV switchyard within the current property line to accommodate the above additional facilities.

The station planning study at EGB is based on the following assumptions:

1. Coordination with the EGB switching station construction project may be needed.
2. The EGB configuration will be confirmed by Design Engineering and the future configuration may be revised to accommodate evolving requirements.

Refer to the sketch in Appendix C for the work scope at EGB.

The scope of work at SLS includes:

This work scope addresses the thermal overload on the 230 kV line 2L308, identified by the section 5.1.1, involves installing a 600 MVA, 230 kV phase-shifting transformer on 2L312 at the Sundance Lakes Substation, along with bypass facilities.

- Install a 600 MVA, 230 kV phase-shifting transformer with its bypass and associated equipment on 2L312.
- Relocate and re-terminate 230 kV line 2L312 and associated equipment to the existing line terminal.
- Complete other associated station works for the above changes.
- Expand the control building, if required, to accommodate new P&C panels and other equipment. Engineering design to confirm.
- Expand the existing station fence to the west to accommodate the above additional facilities. Additional property is required.

The station work at SLS is based on the following assumptions:

1. It is feasible to obtain additional property and expand the SLS station to accommodate a 600 MVA, 230 kV phase-shifting transformer and its bypass on 230 kV line 2L312. Alternatively, the existing property could be used by rearranging the layout, without impacting the station’s future expansion.
2. The configuration of the phase shifting transformer, along with its associated equipment and bypass may change and will be confirmed in the next stage.
3. The control building at SLS is expandable to accommodate the new upgrade if necessary.

Refer to the sketch in Appendix C for the work scope at SLS.

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, a new tap structure on the 230 kV line 2L329 with tap connection is not acceptable to interconnect the customer's generating project to the BCH system. Instead, it is recommended that the POI be changed to the 230 kV bus of the planned East Groundbirch switching station, which is required to loop in the line 2L329 and is located approximately 14 km from the SGB. The EGB switching station is being built by looping in the existing line 2L333 to support a TVC interconnection request and is currently in the construction phase.

   Three new 230 kV line positions at EGB are required to loop in 2L329 and to interconnect the proposed [redacted].

2. Thermal overload on the 230 kV line 2L308 (GMS-DKT) is observed during summer light load period under system normal condition (P0). The required system reinforcement is to install one 600 MVA, 230 kV phase shifting transformer with bypass facilities on 2L312 at the 230 kV Sundance Lakes Substation.

3. With the connection of [redacted], the following thermal overloads have been identified under single contingency conditions:

   - 2L392 overload under the single contingency of loss of 2L308 (P1).
   - 2L308 overloads under the single contingency of loss of 2L392-A (SGB-TYTX) or SBK_2CB21 (or 2CB22) breaker internal fault (P2).
   - GMS 500/230 kV transformers T13 or T14 overloads under single contingencies of loss of GMS 500/230 kV T14 or T13 or internal breaker failure GMS-1CB4 or 1CB5, 1CB7.

   The [redacted] is required to participate in and modify the existing Peace Area Wind Farm Gen Shedding RAS.

   - Thermal overloads on 500 kV lines 5L1, 5L2 and 5L3 under single contingencies loss of one of 500 kV line, 5L3, 5L4, or 5L7. The [redacted] is required to participate in the G.M. Shrum Area Gen Shedding RAS.

Further details of the RASs will be studied under System impact study stage.

4. The [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.

5. A Direct Transfer Trip 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 existing loads.

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. Based on the IC-submitted PSS/E model, the proposed [redacted] does not meet the reactive capability requirement above. It requires an additional 1.27 MVAr capacitive reactive power.

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. BC Hydro recognizes that Type-3 WTGs with the STATCOM option have an inherent limitation—providing only partial reactive power capability during turbine standstill.

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

Appendix A
Schematic Diagram of the IC's Project

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

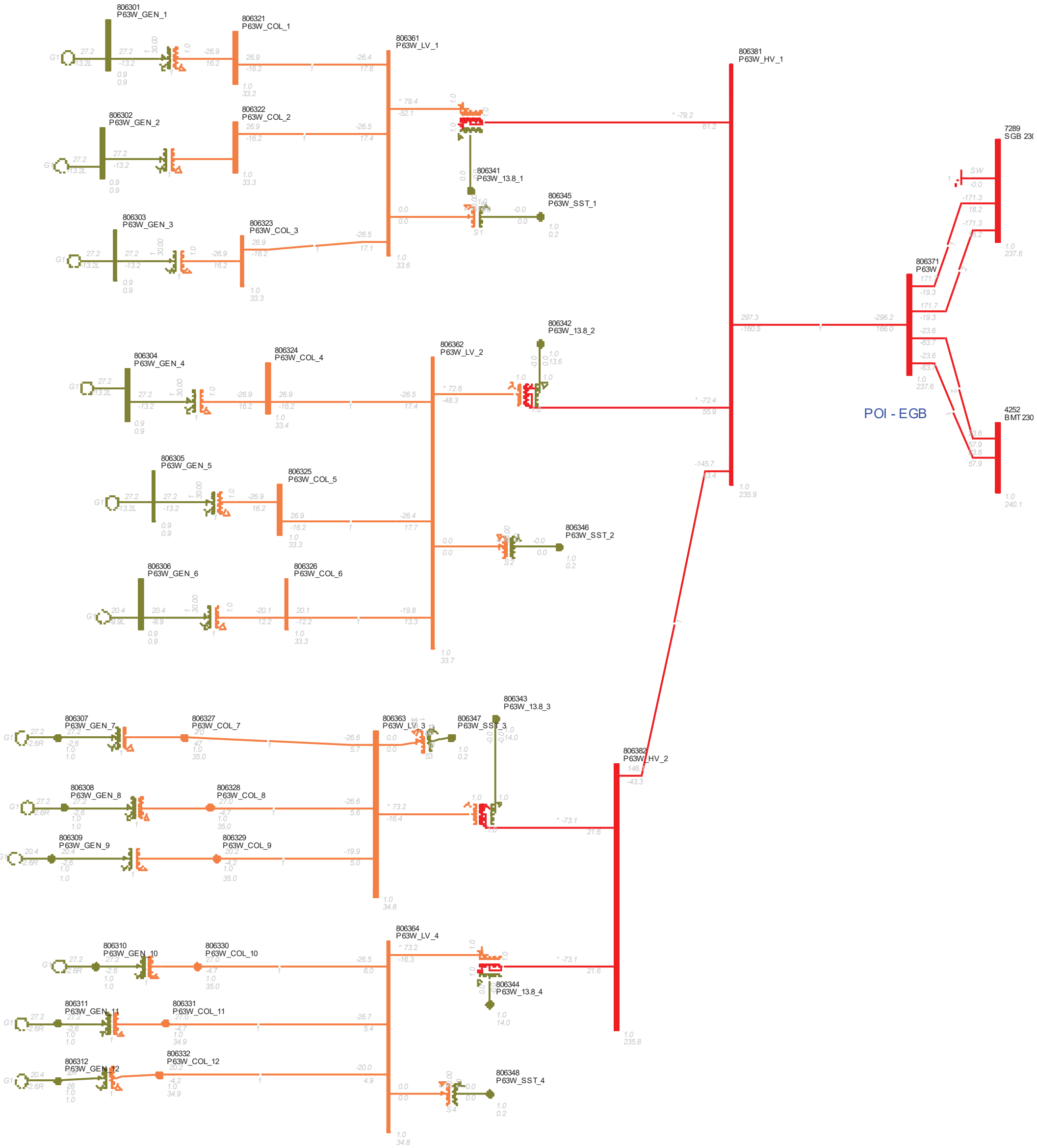


Figure A-1: [redacted] Plant Schematic Diagram.

Appendix B
Power Flow Study Results

Base Scenario (29HW/30LS/32HS/32LS)

Table B-1: Thermal Overload Study Results

Cases	IC's Gen Output (MW)	Contingency		Branch Loading (Amps/MVA)						
				5L1	2L312	2L308	2L329-A	2L333-A	2L392	GMS T14
		Cate.	Description	GMS-KDY	SNK-SLS	GMS-DKT	SGB-EGB	SGB-EGB	SBK-SGB	(MVA)
Winter Rating				3000	1351	1359	2000	2000	1667	356
29HW	Max	P0	System Normal	1702.6 56.8%	533.7 39.5%	742.6 54.6%	161.0 8.0%	161.0 8.0%	215.5 12.9%	137.5 38.6%
		P1	2L308	1692.8 56.4%	1271.1 94.1%	N/A	193.6 9.7%	193.6 9.7%	528.2 31.7%	12.9 3.6%
		P1	2L312	1708.1 56.9%	N/A	1276.2 93.9%	156.6 7.8%	156.6 7.8%	21.9 1.3%	239.1 67.2%
		P1	2L333-A (SGB-EGB)	1702.8 56.8%	532.7 39.4%	742.8 54.7%	317.9 15.9%	N/A	216.6 13.0%	137.5 38.6%
		P1	GMS T13	1702.4 56.7%	601.7 44.5%	672.7 49.5%	162.2 8.1%	162.2 8.1%	244.3 14.7%	248.9 69.9%
		P1	5L3	2649.9 88.3%	501.8 37.1%	795.5 58.5%	173.8 8.7%	173.8 8.7%	190.5 11.4%	145.2 40.8%
		P1	2L329-A (SGB-EGB)	1702.8 56.8%	532.7 39.4%	742.8 54.7%	N/A	317.9 15.9%	216.6 13.0%	137.5 38.6%
		P1	2L329-B (BMT-EGB)	1702.6 56.8%	533.6 39.5%	742.5 54.6%	160.4 8.0%	160.4 8.0%	215.5 12.9%	137.5 38.6%
Summer Rating				2244	1066	1073	1954	1954	1343	300
30LS	Max	P0	System Normal	1774.5 79.1%	474.2 44.5%	835.4 77.9%	264.3 13.5%	264.3 13.5%	322.9 24.0%	152.2 50.7%
		P1	2L308	1762.7 78.6%	1307.4 122.6%	N/A	284.2 14.5%	284.2 14.5%	677.3 50.4%	16.0 5.3%
		P1	2L312	1779.3 79.3%	N/A	1311.5 122.2%	265.2 13.6%	265.2 13.6%	120.7 9.0%	242.7 80.9%
		P1	2L333	1774.5 79.1%	473.4 44.4%	835.5 77.9%	528.6 27.0%	N/A	323.5 24.1%	152.2 50.7%
		P1	GMS T13	1774.0 79.1%	548.1 51.4%	760.6 70.9%	264.8 13.6%	264.8 13.6%	356.7 26.6%	276.1 92.0%
		P1	5L3	2777.1 123.8%	441.9 41.5%	891.6 83.1%	269.6 13.8%	269.6 13.8%	297.0 22.1%	159.6 53.2%
		P1	2L329-A (SGB-EGB)	1774.5 79.1%	473.4 44.4%	835.5 77.9%	N/A	528.6 27.0%	323.5 24.1%	152.2 50.7%
		P1	2L329-B (BMT-EGB)	1774.5 79.1%	474.0 44.5%	835.4 77.9%	264.4 13.5%	264.4 13.5%	323.0 24.1%	152.2 50.7%
32LS	Max	P0	System Normal	1885.5 84.0%	342.7 32.2%	971.9 90.6%	266.2 13.6%	266.2 13.6%	689.0 68.6%	177.0 59.0%
		P0	System Normal (Light Load)	2089.4 93.1%	241.9 22.7%	1142.5 106.5%	419.9 21.5%	419.9 21.5%	840.0 83.7%	220.3 73.4%
		P1	2L308	1870.4 83.4%	1307.6 122.7%	N/A	273.3 14.0%	273.3 14.0%	1011.3 100.7%	17.5 5.8%

Cases	IC's Gen Output (MW)	Contingency		Branch Loading (Amps/MVA)						
				5L1	2L312	2L308	2L329-A	2L333-A	2L392	GMS T14
		Cate.	Description	GMS-KDY	SNK-SLS	GMS-DKT	SGB-EGB	SGB-EGB	SBK-SGB	(MVA)
		P1	2L312	1889.6 84.2%	N/A	1312.5 122.3%	268.1 13.7%	268.1 13.7%	576.5 57.4%	241.2 80.4%
		P1	2L333	1885.4 84.0%	342.3 32.1%	971.8 90.6%	531.9 27.2%	N/A	688.9 68.6%	176.9 59.0%
		P1	GMS T13	1884.8 84.0%	426.8 40.0%	887.6 82.7%	266.0 13.6%	266.0 13.6%	720.4 71.7%	321.5 107.2%
		P1	2L392-A (SBK-TYTX)	1886.4 84.1%	190.0 17.8%	1135.0 105.8%	265.8 13.6%	265.8 13.6%	N/A	208.1 69.4%
		P1	5L3	2962.8 132.0%	316.3 29.7%	1031.1 96.1%	265.6 13.6%	265.6 13.6%	681.6 67.9%	183.8 61.3%
		P1	2L329-A (SGB-EGB)	1885.4 84.0%	342.3 32.1%	971.8 90.6%	N/A	531.9 27.2%	688.9 68.6%	176.9 59.0%
		P1	2L329-B (BMT-EGB)	1885.5 84.0%	342.5 32.1%	971.9 90.6%	266.5 13.6%	266.5 13.6%	689.1 68.6%	177.0 59.0%
		P2	SBK_2CB21	1887.1 84.1%	146.2 13.7%	1186.8 110.6%	265.8 13.6%	265.8 13.6%	N/A	217.9 72.6%
32HS	Max	P0	System Normal	1831.0 81.6%	398.0 37.3%	914.6 85.2%	192.6 9.9%	192.6 9.9%	633.5 63.1%	161.6 53.9%
		P1	2L308	1816.7 81.0%	1307.9 122.7%	N/A	202.6 10.4%	202.6 10.4%	935.3 93.1%	21.5 7.2%
		P1	2L312	1835.6 81.8%	N/A	1312.4 122.3%	193.7 9.9%	193.7 9.9%	501.6 50.0%	237.2 79.1%
		P1	2L333	1831.0 81.6%	397.5 37.3%	914.5 85.2%	385.2 19.7%	N/A	633.5 63.1%	161.6 53.9%
		P1	GMS T13	1830.4 81.6%	476.1 44.7%	836.3 77.9%	192.6 9.9%	192.6 9.9%	661.0 65.8%	293.2 97.7%
		P1	2L392-A (SBK-TYTX)	1832.3 81.7%	253.9 23.8%	1064.2 99.2%	192.7 9.9%	192.7 9.9%	N/A	190.4 63.5%
		P1	5L3	2858.8 127.4%	370.2 34.7%	970.8 90.5%	193.3 9.9%	193.3 9.9%	627.9 62.5%	168.6 56.2%
		P1	2L329-A (SGB-EGB)	1831.0 81.6%	397.5 37.3%	914.5 85.2%	N/A	385.2 19.7%	633.5 63.1%	161.6 53.9%
		P1	2L329-B (BMT-EGB)	1831.0 81.6%	397.9 37.3%	914.5 85.2%	192.6 9.9%	192.6 9.9%	633.5 63.1%	161.6 53.9%
		P2	SBK_2CB21	1832.8 81.7%	213.0 20.0%	1108.5 103.3%	192.7 9.9%	192.7 9.9%	N/A	198.9 66.3%

Table B-2: Steady-State Voltage Study Results

Case	IC's Generator Output (MW)	Contingency		Bus Voltage (PU)		
		Cate.	Description	SGB 230	SNK 230	BMT 230
29HW	Max	P0	System Normal	1.029	1.039	1.032
		P1	2L308	1.022	1.035	1.028
		P1	2L312	1.032	1.040	1.033
		P1	2L333-A (SGB-EGB)	1.028	1.039	1.032
		P1	GMS T13	1.029	1.039	1.032
		P1	5L3	1.026	1.037	1.030

Case	IC's Generator Output (MW)	Contingency		Bus Voltage (PU)		
		Cate.	Description	SGB 230	SNK 230	BMT 230
		P1	2L329-A (SGB-EGB)	1.028	1.039	1.032
		P1	2L329-B (BMT-EGB)	1.029	1.046	1.032
30LS	Max	P0	System Normal	1.030	1.037	1.032
		P1	2L308	1.021	1.032	1.027
		P1	2L312	1.033	1.039	1.033
		P1	2L333	1.029	1.037	1.032
		P1	GMS T13	1.030	1.037	1.032
		P1	5L3	1.026	1.035	1.030
		P1	2L329-A (SGB-EGB)	1.029	1.037	1.032
		P1	2L329-B (BMT-EGB)	1.030	1.042	1.032
32LS	Max	P0	System Normal	1.033	1.038	1.033
		P1	2L308	1.025	1.035	1.029
		P1	2L312	1.035	1.039	1.034
		P1	2L333	1.032	1.038	1.033
		P1	GMS T13	1.032	1.038	1.033
		P1	2L392-A (SBK-TYTX)	1.032	1.038	1.033
		P1	5L3	1.031	1.038	1.032
		P1	2L329-A (SGB-EGB)	1.032	1.038	1.033
		P1	2L329-B (BMT-EGB)	1.033	1.043	1.033
		P2	SBK_2CB21	1.032	1.038	1.033
32HS	Max	P0	System Normal	1.032	1.039	1.033
		P1	2L308	1.026	1.036	1.030
		P1	2L312	1.034	1.040	1.034
		P1	2L333	1.032	1.039	1.033
		P1	GMS T13	1.032	1.039	1.033
		P1	2L392-A (SBK-TYTX)	1.032	1.039	1.033
		P1	5L3	1.031	1.038	1.032
		P1	2L329-A (SGB-EGB)	1.032	1.039	1.033
		P1	2L329-B (BMT-EGB)	1.032	1.044	1.033
		P2	SBK_2CB21	1.031	1.039	1.033

Appendix C

One-Line Sketch for Switching Station

Figure C-1 shows the Stations Planning One-Line Sketch for the Switching Station EGB.

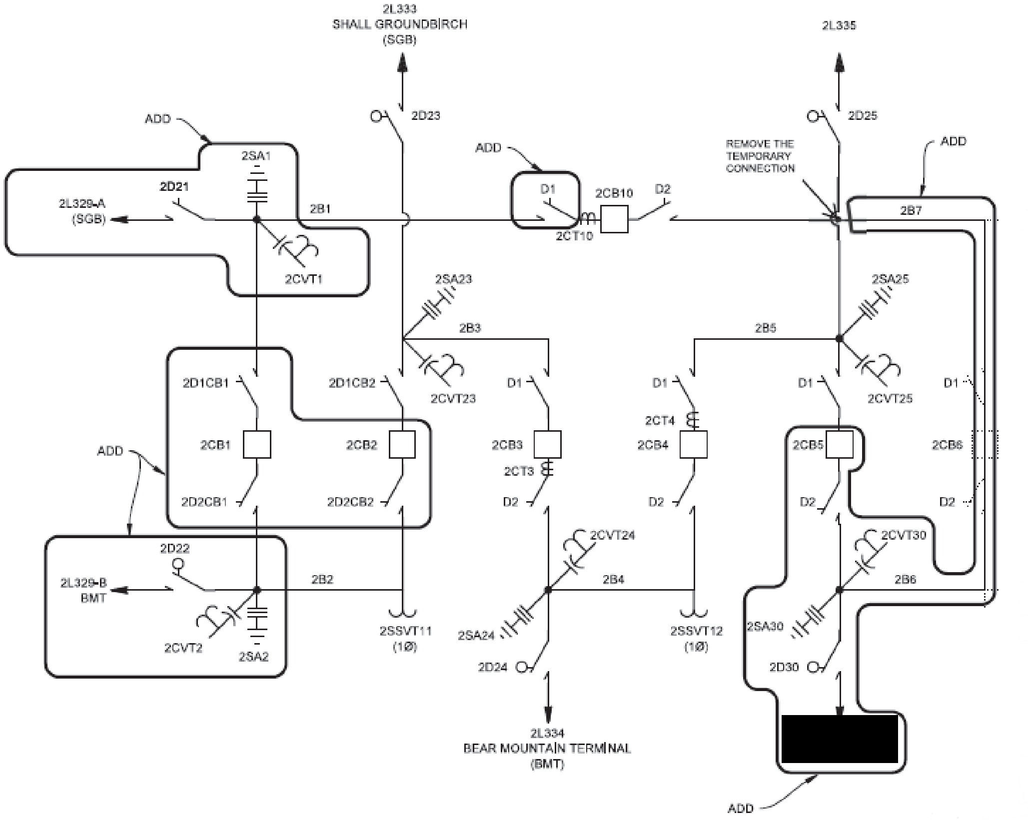
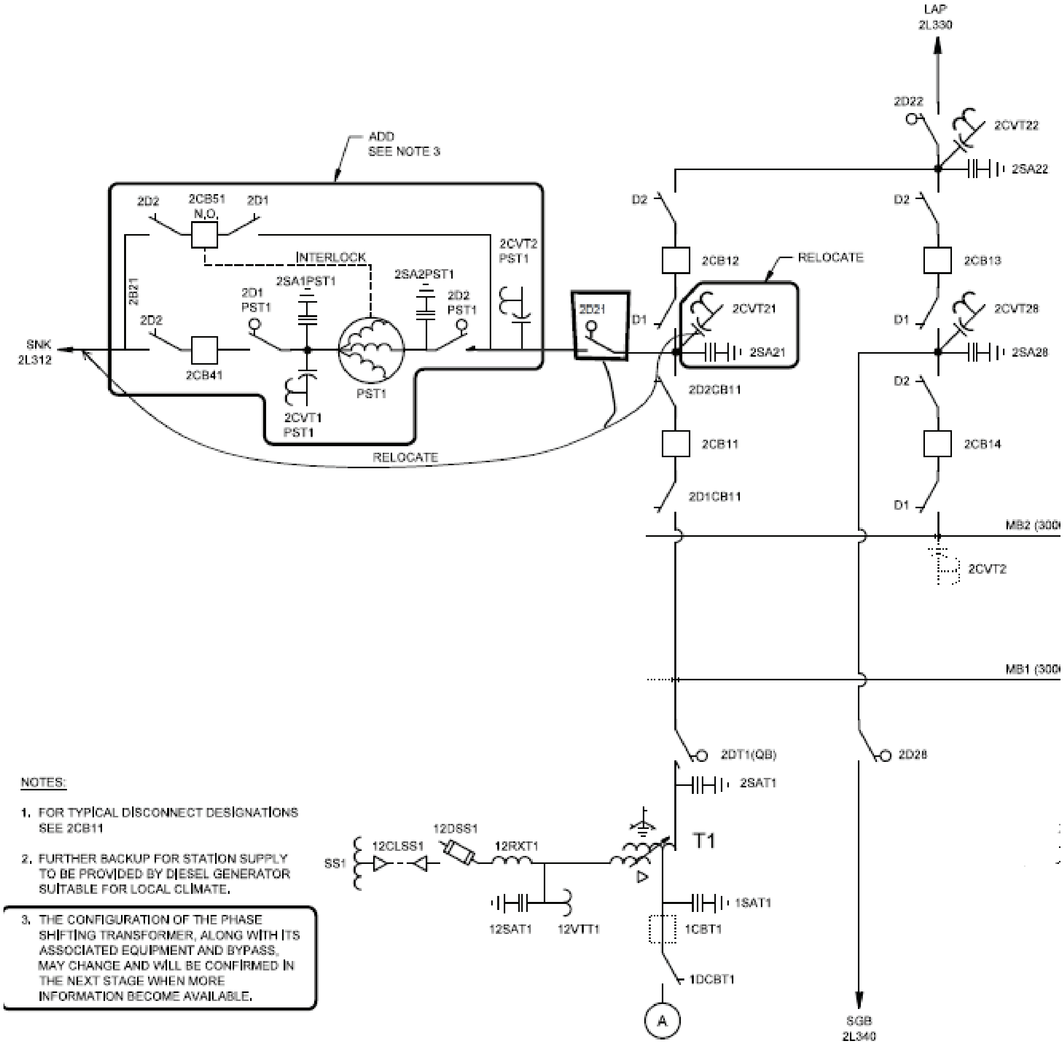


Figure C-1: Stations Planning One-Line Sketch for the Switching Station EGB.



NOTES:

1. FOR TYPICAL DISCONNECT DESIGNATIONS SEE 2CB11
2. FURTHER BACKUP FOR STATION SUPPLY TO BE PROVIDED BY DIESEL GENERATOR SUITABLE FOR LOCAL CLIMATE.
3. THE CONFIGURATION OF THE PHASE SHIFTING TRANSFORMER, ALONG WITH ITS ASSOCIATED EQUIPMENT AND BYPASS, MAY CHANGE AND WILL BE CONFIRMED IN THE NEXT STAGE WHEN MORE INFORMATION BECOME AVAILABLE.

Figure C-2: Stations Planning One-Line Sketch for the Switching Station SLS.