BC Hydro
Power smart

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

November 24, 2025

[redacted]

*via email:* [redacted]

**RE: CEAP IR #25 – [redacted] – Interconnection Feasibility Study**

Dear [redacted]

Enclosed is the Interconnection Feasibility Study for the proposed Interconnection Request (IR), [redacted] [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 $25.2 M.

**Major Scope of Work Identified:**

- Add one 60 kV line position with associated equipment including two circuit breakers with disconnects at BC Hydro's Rupert substation (RUP)
- Terminate [redacted] project wind line with associated disconnect, surge arresters and capacitor voltage transformers
- Expand the duct back for the underground 60CL1 cable installation

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

**Exclusions:**

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

**Key Assumptions:**

- Construction by contractor
- 12 months of construction is considered
- No construction during winter season
- Execution of early Engineering and Procurement Agreement
- No expansion of control buildings to accommodate new equipment
- Impact Benefit Agreements with First Nations are not considered
- Site expansion is required, assumed area is 25m x 5m

**Key Risks:**

- Expansion of the existing control building may be required leading to increased costs and/or a longer project schedule
- Major equipment delivery presents potential project cost and schedule risks, based on variance in equipment lead times
- No defined supply chain strategy; construction costs may increase depending on delivery method
- Project schedule may be longer than expected, leading to increased overhead costs
- Ground improvements may be required leading to increased construction costs
- Contaminated soil may be encountered leading to increased construction costs
- Cost of materials and major equipment may be affected by market conditions and escalation

## Study Limitations and Exclusions

### *Protection, Control, and Telecommunications*

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

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

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

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

### *Revenue Metering*

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

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

## Schedule

Based on the Interconnection Feasibility Study, the non-binding good faith estimated in-service date for your Interconnection Request's Network Upgrades is Quarter 3 2031 (calendar year). To achieve this timeline, we may need to expedite certain activities, including engineering design and procurement of long-lead equipment.

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

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

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

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

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

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

Sincerely,

[redacted]

[redacted]

Manager, Customer Interconnections

BC Hydro

Encl.: CEAP_2025_IR25_[redacted]Feasibility_Study.pdf

[redacted]

# Interconnection Feasibility Study

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

**2025 CEAP IR # 25**

Prepared for: [redacted]

Prepared by: [redacted]

Specialist Engineer, Planning Coordinator
& Bulk Planning

[redacted]

Reviewed by: [redacted]

Team Lead, Planning Coordinator & Bulk

Accepted by: [redacted]

Manager, Transmission Planning

# Report Metadata

| | |
|---|---|
| Header: | 2025 CEAP IR# 25 |
| Subheader: | Interconnection Feasibility Study |
| Title: | [redacted] |
| Subtitle: | 2025 CEAP IR # 25 |
| Report Number: | 900-APR-00029 |
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| Confidentiality: | Public |
| Date: | 2025 Nov 21 |
| Volume: | 1 of 1 |
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| Prepared for: | [redacted] |
| Prepared by: | [redacted] |
| Title: | Specialist Engineer, Planning Coordinator & Bulk Planning |
| Checked by: | [redacted] |
| Title: | Sr. Engineer, Planning Coordinator & Bulk Planning |
| Reviewed by: | [redacted] |
| Title: | Team Lead, Planning Coordinator & Bulk Planning |
| Accepted by: | [redacted] |
| Title: | Manager, Transmission Planning |
| Related Facilities: | RUP |
| Additional Metadata: | Transmission Planning 2025-064<br>Filing Subcode 1350 |

# Revisions

| Revision | Date | Description |
|---|---|---|
| 0 | 2025 Nov | Initial release |

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# Contributors

The following accept responsibility for the content in the specified sections. Professionals apply their signature and/or seal as appropriate.

**Section:** Entire report except listed below

**Discipline:** Transmission Planning

Contributed by:

[redacted]

Specialist Engineer, Planning Coordinator & Bulk Planning

[redacted]

**Section:** **5.2, 5.3**

**Discipline:** Stations Planning

Contributed by:

[redacted]

Specialist Engineer, Station Planning

[redacted]

# Executive Summary

[redacted] the interconnection customer (IC), requests to interconnect its [redacted] to the BC Hydro system. [redacted] has seven (7) [redacted] type-3 wind turbine generators, adding a total max installed capacity of 41.3 MW. The Point of Interconnection (POI) is on BC Hydro's 66 kV line bus on Rupert substation (RUP). The IC's proposed commercial operation date (COD) is Nov 1, 2029.

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

1. A new 66 kV line position is required at RUP substation to facilitate the interconnection of [redacted] Station work at RUP will involve installing two new 60 kV circuit breakers with associated disconnect switches to create a line position for the [redacted] customer, terminating the [redacted] transmission line (60LXXX) with its disconnect and a capacitor voltage transformer, and expanding the control building if necessary to accommodate new Protection & Control panels and related equipment.

2. The connection of [redacted] [redacted] [redacted] does not cause any performance violation (i.e. thermal overload, voltage performance violation or voltage stability concern) under system normal conditions or P1/P2 Contingencies.

3. [redacted] is required to install anti-islanding protection within its facility to disconnect the IC's generating plant from the grid when an inadvertent island with the local load forms. The anti-islanding protection shall be configured in the manner that does not compromise the required ride-through performance.

4. The [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.

5. 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.

6. 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 |
| CEAP | Competitive Electricity Acquisition Process |
| COD | Commercial Operation Date |
| DTT | Direct Transfer Trip |
| ERIS | Energy Resource Interconnection Service |
| FeS | Feasibility Study |
| IBR | Inverter-Based Resources |
| IC | Interconnection Customer |
| IR | Interconnection Request |
| LAPS | Local Area Protection Schemes |
| MPO | Maximum Power Output |
| NERC | North American Electric Reliability Corporation |
| NRIS | Network Resource Interconnection Service |
| OATT | Open Access Transmission Tariff |
| POI | Point of Interconnection |
| RAS | Remedial Action Scheme |
| TIR | BC Hydro “60 KV to 500 kV Technical Interconnection Requirements for Power Generators” |
| WECC | Western Electricity Coordinating Council |
| WTG | Wind Turbine Generator |

# 1 Introduction

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

Table 1-1 Summary of Project Information

| | | |
|---|---|---|
| Project Name | [redacted] | |
| Name of Interconnection Customer (IC) | [redacted] | |
| Point of Interconnection (POI) | on 66 KV bus at RUP | |
| IC's Proposed COD | 1st November 2029 | |
| Type of Interconnection Service | NRIS ☒ | ERIS ☐ |
| Maximum Power Installed Capacity (MW) | 41.3 MW (Summer) | 41.3 MW (Winter) |
| Maximum Power Injection (MW) | 39.7 MW (Summer) | 39.7 MW (Winter) |
| Number of Turbines | 7 x 5.9 MW WTGs | |
| Plant Fuel | Wind | |

[redacted] the interconnection customer (IC), requests to interconnect its [redacted] to the BC Hydro system. [redacted] has seven (7) [redacted] type-3 wind turbine generators, adding a total max installed capacity of 41.3MW into the BC Hydro system. The Point of Interconnection (POI) is on BC Hydro's 66 kV bus in Rupert substation (RUP). The IC will construct a 66 kV transmission line, about 4.5 km in length, connecting the proposed POI and customer substation [redacted] (customer substation name is subject to change). The proposed commercial operation date (COD) is Nov 1, 2029.

Figure 1-1 shows the Prince Rupert region transmission system diagram. RUP is a 287/66 kV substation with two 287/66 kV transformers and supplies power to BC Hydro customers in the region via four 66 kV transmission lines. The interconnection point of RUP 66 is fed from SKA substation. SKA substation is connected to the BC Hydro 500kV system. Customer's system topology behind the Point of Interconnection is provided in the Appendix, Figure A-1.

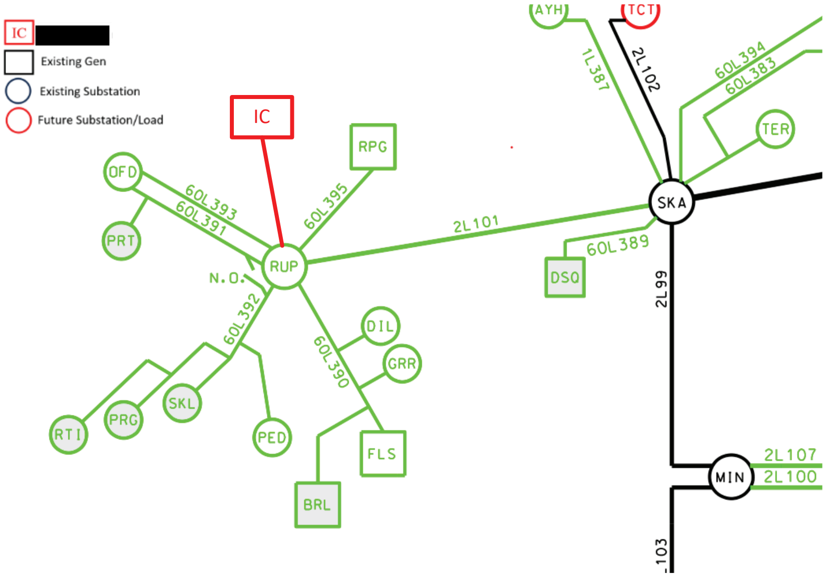

Figure 1-1: RUP Region 287/66 kV Transmission System Diagram

# 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 P0, P1 and P2 planning events as defined in TPL-001-4 and short circuit analysis. The study does not address other technical aspects such as transient stability and switching transients and impact of multiple contingencies. These subjects will be addressed in subsequent System Impact Study if the project proceeds further. In addition, any potential impacts to the adjacent external systems to BC Hydro would be addressed in subsequent detailed and coordinated studies with the relevant adjacent entities if the proposed generator project proceeds further.

Please note that, due to the compressed study timeline for 2025 CEAP Feasibility Study, this report does not include the descriptions of the Protection, Control, and Telecommunication requirements and the associated upgrade scopes. Instead, the network upgrades associated with Protections, Controls and Telecommunications are incorporated with cost estimates in a separate cover letter to the IC.

# 3 Standard and Criteria

The Feasibility Study is performed in compliance with the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards, and the BCH interconnection requirements in the TIR, and upon the ratings of the existing BCH transmission facilities described in Operating Orders, specifically:

- NERC standards: TPL-001-4 and FAC-002-3 relevant to the scope of this Feasibility Study.
- WECC criteria TPL-001-WECC-CRT-4 Transmission System Planning Performance, July 1, 2023.
- BC Hydro's 60 kV to 500 kV Technical Interconnection Requirements for Power Generators, Rev 2.1.1, Effective: Sept 22, 2025.
- BC Hydro Operating Order 5T-10, Ratings for All Transmission Circuits 60 kV or Higher, Sept 17, 2025.
- BC Hydro Operating Order 5T-14, Ratings for All Transmission and Distribution Transformer, Sept 22, 2025.
- BC Hydro System Operating Order 7T-22 System Voltage Control, October 7, 2025.

# 4 Assumptions and Conditions

This Feasibility Study is performed based on the IC's submitted data and information available to BC Hydro on Oct 14, 2025, for the study purpose. Assumptions are made wherever the IC's input is unavailable. Appendix A shows the schematic diagram of the IC's Project used in the study model.

The power flow study cases used in this Feasibility Study are established based upon the BC Hydro's base resource plan and load forecasts available at the time of performing the study, which includes existing and future generators, transmission facilities, and loads in addition to the subject interconnection project in this study. Applicable seasonal conditions and the appropriate study years for the study planning horizon are also incorporated. Additional assumptions are listed as follows.

1) The generation in the study area are dispatched to the patterns that stress the transmission system in the study area. In these patterns, the associated generators are typically set to their Maximum Power Outputs (MPO) unless otherwise specified.

2) 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.
    a. Prince George to Terrace series Capacitor project to be installed in existing lines 5L61, 5L62 and 5L63.
    b. New 500kV lines: 5L64 in PGGT and 5L65& 5L66 (WSN to SKA) in GTTT.
    c. Other system reinforcements in the regional system triggered by future load customer interconnections are also included in the study model.

# 5 System Studies and Results

Based upon the IC's submitted information and the area system conditions, new line positions and associated station work will be needed to accommodate the integration of IC's requested project [redacted] Details of the study results and reinforcement scopes required to integrate the IC is provided in this section.

## 5.1 Power Flow Study Results

Steady-state power flow studies were performed to evaluate whether the IC's generating project would cause any unacceptable system performance (e.g. equipment overloads, steady-state voltage violation and voltage instability) and to determine the system reinforcement requirement based on steady state performance analysis.

The study focuses on the base scenario — 29HW/30LS/30HS system conditions that include all the higher-queued load projects in the region and the future proposed reinforcements. These base cases were prepared based on factors such as load conditions, seasonal variation in ambient temperatures, and generation patterns that stress the transmission system.

The studies are performed for system normal conditions and under critical system contingencies specified in the P1 and P2 events by NERC TPL-001-4. Study results are summarized below.

### 5.1.1 Thermal Overload Analysis

The study shows that the addition of [redacted] would not cause any new thermal overloads under system normal condition or contingency conditions.

The study shows that the addition of [redacted] would not cause any new thermal overloads under P1/P2 contingency conditions.

The existing North coast Region Gen shedding RAS addresses the system performance issues related to the multiple contingencies in the North Coast transmission system. [redacted] is required to participate in the existing North Coast Region generator shedding RAS. The detailed RAS studies will be covered in detail the next phase of the study.

Appendix B, Table B-1 provides the details of thermal loading analysis results.

### 5.1.2 Steady-State Voltage Analysis

With the connection of the IC's project, the stead-state voltage performance under system normal and single contingency conditions is acceptable for all the three load conditions (30LS, 30HS, 29HW). Appendix B, Table B-2 provides 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 power flow model data submitted by the IC, the proposed [redacted] would be capable of meeting the BC Hydro's reactive capability requirement at the plant's maximum MW output. Further verification will be conducted in the next stage of the interconnection study.

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. 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.

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

## 5.3 Stations Requirements

The POI of the [redacted] facility will be 66 kV switchyard of the existing Rupert substation (RUP).

Following is the scope of station work in RUP:

- Add two new 60 kV circuit breaker with associated disconnects to create line position for the [redacted] wind customer.
- Terminate [redacted] wind 60 kV 60LXXX transmission line with associated disconnect, and capacitor voltage transformer.
- Design to confirm the feasibility of the underground transmission line egress.
- Expand the control building, if required, to accommodate new P&C panels and other equipment.
- The underground 60CL1 cable installation may require extension of the duct bank which may trigger substation expansion; this will be confirmed in next phase of the project after consultation with Engineering design.
- Other associated station work.

## 5.4 Transmission Line Engineering Requirements

No transmission line engineering scope of work is identified for BC Hydro for this project.

# 6 Cost Estimate and Schedule

The non-binding good faith estimated cost and time to construct the Network Upgrades required to interconnect the proposed project will be provided in a separate letter to the IC.

# 7 Conclusions

To interconnect the [redacted] and its facilities to the BCH Transmission System at the POI, this Feasibility Study has identified the following conclusions and requirements:

1. A new 66 kV line position is required at RUP substation to facilitate the interconnection of [redacted] Station work at RUP will involve installing two new 60 kV circuit breakers with associated disconnect switches to create a line position for the [redacted] customer, terminating the [redacted] 60 kV transmission line (60LXXX) with its disconnect and a capacitor voltage transformer, and expanding the control building if necessary to accommodate new Protection & Control panels and related equipment.
2. The connection of [redacted] [redacted] [redacted] does not cause any performance violation (i.e. thermal overload, voltage performance violation or voltage stability concern) under system normal conditions or P1/P2 Contingencies.
3. [redacted] is required to install anti-islanding protection within its facility to disconnect the IC's generating plant from the grid when an inadvertent island with the local load forms. The anti-islanding protection shall be configured in the manner that does not compromise the required ride-through performance.
4. The [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.
5. 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.
6. Fast Frequency Response, also known as Virtual Inertia Control (VIC) in the proposed wind turbines, is required at the [redacted]

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

# Appendix A

# Schematic Diagram of the IC's Project

Figure A-1 shows the schematic diagram for the [redacted] Note that the proposed plant configuration includes a total of 12 Mvar shunt capacitors.

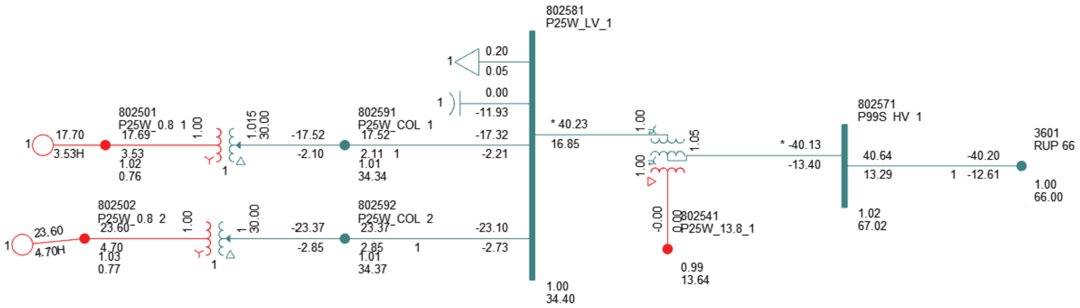

Figure A-1: [redacted] Schematic Diagram.

# Appendix B

# Power Flow Study Results

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

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

| Case | NC+NW Regional Generation/ Load | Contingency Identified | | Branch Loading | | | |
|---|---|---|---|---|---|---|---|
| | | | | 2L102 | 2L101 | SKA T1 | SKA T3 |
| | | Category | Description | TCT-SKA | SKA-RUP | Winding1/Winding2 | Winding1/Winding2 |
| Winter Rating | | | | 734.2 MVA | 198.8 MVA | 798MVA/798 MVA | 806MVA/806 MVA |
| 29HW | 389.9 MW / 584.7MW | P0 | System Normal | 18.5% | 25.0% | 11.8%/12.0% | 17.7%/17.4% |
| | | P1 | 2L374 OOS | 33.3% | 24.7% | 16.1%/16.2% | 21.3%/20.9% |
| | | | 2L101 OOS | 18.5% | OOS | 10.1%/10.2% | 16.7%/16.4% |
| | | | 2L103 OOS | 18% | 25% | 8%/8% | 14%/14% |
| | | | 2L99 OOS | 19.2% | 26.4% | 8.1%/8.4% | 13.6%/13.4% |
| | | | 60L392 OOS | 18.5% | 34.1% | 12.6%/12.8% | 18.3%/17.9% |
| | | P2/P4 | Fault at SKA 5CB3 tripping SKA T1& T2 or, Fault at SKA T1 or T2 with stuck breaker 5CB3 | 19% | 25% | OOS | 34%/34% |
| Summer Rating | | | | 734.2 MVA | 198.8 MVA | 672MVA/672 MVA | 672 MVA/672 MVA |
| 30HS | 389.9MW / 503.3 MW | P0 | System Normal | 21.5% | 32.8% | 18.0%/18.3% | 23.6%/23.2% |
| | | P1 | 2L374 OOS | 32.6% | 33.1% | 21.7/21.9% | 28.9%/28.2% |
| | | | 2L101 OOS | 21.4% | OOS | 14.9%/15.1% | 21.6%/21.2% |
| | | | 2L103 OOS | 22% | 33% | 7%/7% | 15%/15% |
| | | | 2L99 OOS | 21.9% | 33.4% | 12.3%/12.5% | 17.9%/17.6% |
| | | | 60L392 OOS | 21.5% | 41.0% | 18.8%/19.0% | 24.3%/23.8% |
| | | P2/P4 | Fault at SKA 5CB3 tripping SKA T1& T2 or, Fault at SKA T1 or T2 with stuck breaker 5CB3 | 21% | 33 % | OOS | 54 %/54% |
| 30LS | 389.9MW / 415.5 MW | P0 | System Normal | 27.8% | 39.1% | 22.2%/22.5% | 27.1%/26.6% |
| | | P1 | 2L374 OOS | 32.4% | 39.0% | 23.9%/24.1% | 28.6%/28.0% |
| | | | 2L101 OOS | 27.8% | OOS | 18.5%/18.7% | 24.3%/23.8% |
| | | | 2L103 OOS | 28% | 39% | 6%/6% | 15%/15% |
| | | | 2L99 OOS | 28.0% | 39.6% | 15.8%/16.1% | 20.7%/20.3% |
| | | | 60L392 OOS | 27.8% | 43.5% | 22.6%/22.9% | 27.4%/26.9% |
| | | P2/P4 | Fault at SKA 5CB3 tripping SKA T1& T2 or, Fault at SKA T1 or T2 with | 28% | 40% | OOS | 69 %/68% |

|  |  |  |  |  |  |  |  |
|---|---|---|---|---|---|---|---|
|  |  |  | stuck breaker 5CB3 |  |  |  |  |

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

| Case | NC+NW Regional Generation/Load | IC's Generator Output | Contingency |  | Bus Voltage (PU) |  |  |  |  |  |  |  |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
|  |  |  | Category | Description | SKA 500 | TKW 500 | GLN 500 | RUP 287 | RUP 66 (POI) | TCT 287 | MIN 287 | BQN 287 |
| 29HW | 389.9 MW / 584.7MW | 40.1 MW | P0 | System normal | 1.03 | 1.03 | 1.03 | 1.01 | 1.00 | 1.00 | 0.99 | 1.02 |
|  |  |  | P1 | 2L374 OOS | 1.03 | 1.03 | 1.03 | 1.01 | 1.00 | 1.00 | 0.99 | 1.01 |
|  |  |  |  | 2L101 OOS | 1.03 | 1.03 | 1.03 | OOS | OOS | 1.00 | 0.99 | 1.02 |
|  |  |  |  | 2L103 OOS | 1.03 | 1.04 | 1.04 | 1.01 | 1.00 | 1.00 | 0.99 | 1.02 |
|  |  |  |  | 2L99 OOS | 1.04 | 1.04 | 1.04 | 1.02 | 1.00 | 1.00 | OOS | 1.02 |
|  |  |  |  | 60L392 OOS | 1.03 | 1.03 | 1.03 | 1.01 | 1.00 | 1.00 | 0.99 | 1.02 |
|  |  |  | P2/P4 | Fault at SKA 5CB3 tripping SKA T1& T2 or, Fault at SKA T1 or T2 with stuck breaker 5CB2 | 1.02 | 1.03 | 1.03 | 1.01 | 1.00 | 1.00 | 0.99 | 1.01 |
| 30HS | 389.9MW / 503.3 MW | 40.1 MW | P0 | System normal | 1.02 | 1.03 | 1.03 | 1.01 | 0.99 | 1.00 | 0.99 | 1.02 |
|  |  |  | P1 | 2L374 OOS | 1.03 | 1.03 | 1.03 | 1.01 | 1.00 | 1.00 | 0.99 | 1.01 |
|  |  |  |  | 2L101 OOS | 1.02 | 1.03 | 1.03 | OOS | OOS | 1.00 | 0.99 | 1.02 |
|  |  |  |  | 2L103 OOS | 1.01 | 1.03 | 1.04 | 1.01 | 0.99 | 1.00 | 0.99 | 1.02 |
|  |  |  |  | 2L99 OOS | 1.03 | 1.04 | 1.04 | 1.02 | 1.00 | 1.00 | OOS | 1.02 |
|  |  |  |  | 60L392 OOS | 1.02 | 1.03 | 1.03 | 1.01 | 1.00 | 1.00 | 0.99 | 1.02 |
|  |  |  | P2/P4 | Fault at SKA 5CB3 tripping SKA T1& T2 or, Fault at SKA T1 or T2 with stuck breaker 5CB3 | 1.03 | 1.03 | 1.03 | 1.02 | 1.00 | 1.00 | 0.99 | 1.02 |
| 30LS | 389.9MW / 415.5 MW | 40.1 MW | P0 | System normal | 1.02 | 1.02 | 1.02 | 1.01 | 0.99 | 1.02 | 0.99 | 1.04 |
|  |  |  | P1 | 2L374 OOS | 1.02 | 1.02 | 1.02 | 1.01 | 0.99 | 1.02 | 0.99 | 1.04 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | 2L101 OOS | 1.02 | 1.03 | 1.03 | OOS | OOS | 1.02 | 0.99 | 1.04 |
| | | | | 2L103 OOS | 1.01 | 1.04 | 1.04 | 1.01 | 1.00 | 1.02 | 1.00 | 1.04 |
| | | | | 2L99 OOS | 1.03 | 1.04 | 1.03 | 1.02 | 1.00 | 1.02 | OOS | 1.04 |
| | | | | 60L392 OOS | 1.02 | 1.02 | 1.02 | 1.01 | 0.99 | 1.02 | 0.99 | 1.04 |
| | | | P2/P4 | Fault at SKA 5CB3 tripping SKA T1& T2<br>or, Fault at SKA T1 or T2 with stuck breaker 5CB3 | 1.05 | 1.06 | 1.05 | 1.03 | 1.00 | 1.02 | 0.99 | 1.01 |

# Appendix C
# One-Line Sketch for work at RUP substation

Figure C-1 shows the Stations Planning One-Line Sketch for work in RUP substation.

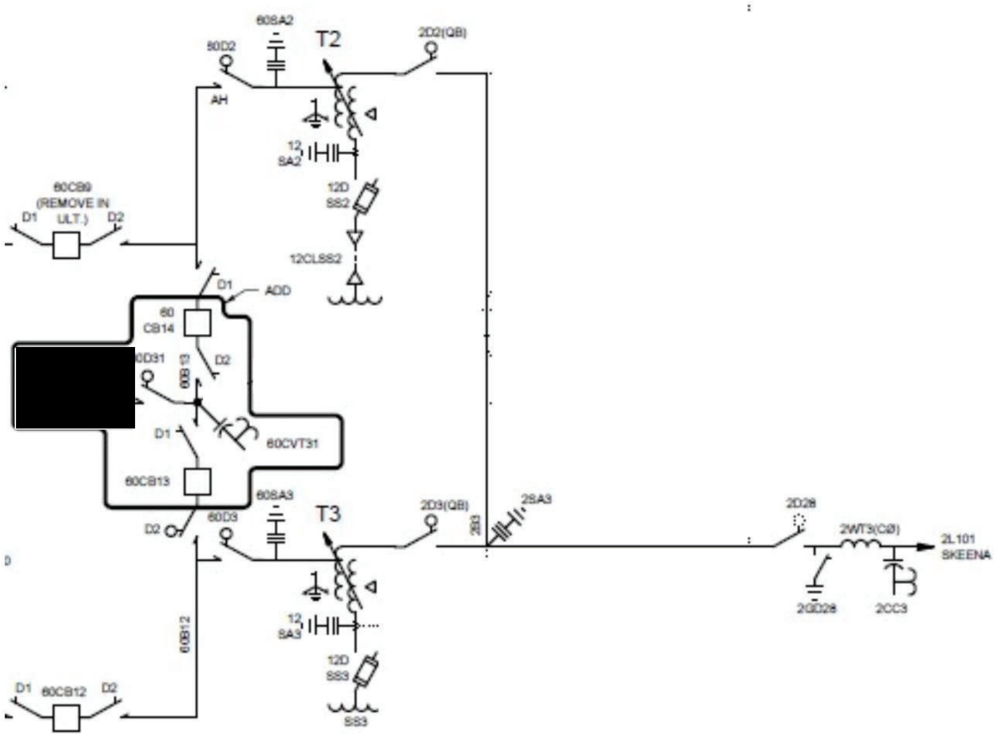
[redacted]

Figure C-1: Station Planning One-Line modification Sketch for the Station RUP.