BC Hydro
Power smart

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

November 24, 2025

[redacted]

via email: [redacted]

RE: CEAP IR #114 – [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 $33.0 M.

Major Scope of Work Identified:

- Install one new 230kV line position with outdoor 230 kV circuit breaker along with associated motorised disconnects at BC Hydro Southbank substation (SBK)
- Install one new 230 kV line terminal for the Interconnection Customer's new 230 kV transmission line with associated motorised disconnect switches and one 230 kV capacitor voltage transformer

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

Exclusions:

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

Key Assumptions:

- Construction by contractor
- 8 months of construction is considered
- Execution of early Engineering and Procurement Agreement
- No expansion of existing stations or control buildings to accommodate new equipment
- No construction during winter season
- 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 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

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_IR114_[redacted]_Feasibility_Study.pdf

[redacted]

Interconnection Feasibility Study

BC Hydro EGBC Permit to Practice No: 1002449

2025 CEAP IR # 114

Prepared for: [redacted]

Prepared by: [redacted] [redacted]

Engineer, Transmission Planning

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Team Lead, Transmission Planning

Accepted by: [redacted]

Manager, Transmission Planning

1000-APR-00067
2025 Nov 21

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Prepared for:	[redacted]
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Revision	Date	Description
0	2025 Nov	Initial release

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Engineer, Transmission Planning

Section: **Discipline:**

5.2, 5.3 — Stations Planning

Contributed by:

[redacted] [redacted]

[redacted]

Specialist Engineer, Station Planning

Executive Summary

[redacted] the Interconnection Customer (IC), requests to interconnect its [redacted] 2025 CEAP IR # 114 - to the BC Hydro (BCH) system. [redacted] has one hundred and seventy-six (176) [redacted] solar inverters with total installed capacity of 704 MW and a maximum power injection of 685.1 MW at the proposed Point of Interconnection (POI). The proposed POI is at BCH's Southbank (SBK) 230 kV substation. The IC will construct a 230 kV transmission line, about 16 km in length, connecting to the proposed POI. The IC's proposed commercial operation date (COD) is July 7, 2030.

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

1. A new 230 kV line position is required at the POI, to facilitate the interconnection of [redacted] Project. The interconnection line, to be built by the IC, is temporarily referred to as 2LXX3. The temporary line designation will be replaced by a permanent one at a later stage of the interconnection process.
2. The connection of [redacted] Project does not cause any performance violation (i.e. thermal overload, voltage performance violation or voltage stability concern) under system normal conditions.
3. The connection of [redacted] Project could exacerbate the pre-existing thermal overloads (and/or transient stability) issues on BCH's 500 kV and regional transmission system under single contingencies or circuit breaker related contingencies. To address these issues, the new [redacted] Project is required to participate in the Generation Runback or Shedding Remedial Action Scheme (RAS) to secure the system. The RAS function scope will be specified in the System Impact Study (SIS).
4. [redacted] Project is required to install anti-islanding protection within its facility to disconnect the IC's solar farm 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. The [redacted] Project 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. The [redacted] Project does not meet the reactive power capability requirement above. Installation of minimum of 30 MVAr shunt compensation is required at the IC's facility to meet the requirement. This requirement needs to be addressed if the project proceeds to the next stage of the interconnection process.
6. The "Reactive Power at Night" function [or "Reactive Power at Zero Output"] for the proposed solar inverter is required so that each inverter can provide reactive power capability at zero MW output including during nighttime.

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
ELCC	Effective Load Carrying Capacity
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
OOS	Out-of-Service
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

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)	Southbank (SBK) substation 230 kV	
IC's Proposed COD	7 July 2030	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	685.1 MW (Summer)	685.1 MW (Winter)
Number of Inverters	176 × 4 MW	
Plant Fuel	Solar	

[redacted] the Interconnection Customer (IC), requests to interconnect its [redacted] 2025 CEAP IR # 114 - to the BC Hydro (BCH) system. [redacted] Project has one hundred and seventy-six (176) [redacted] solar inverters with total installed capacity of 704 MW and a maximum power injection of 685.1 MW at the proposed Point of Interconnection (POI). The proposed POI is at BCH's Southbank (SBK) 230 kV substation. The IC will construct a 230 kV transmission line, about 16 km in length, connecting to the proposed POI. The IC's proposed commercial operation date (COD) is July 7, 2030.

Figure 1-1 shows the Peace Region bulk 500 kV and regional 138/230 kV transmission system diagram. 1L377 is normally open between [redacted] Tower 03/07 (ET3) and Parkland (PLD) substations. The IC, temporarily designated as P114, is interconnected through a 16 km, 230 kV transmission line to SBK 230 kV substation and is depicted in blue. The Peace region 138/230 kV system has pre-existing branch overload and voltage stability concerns under single or multiple contingencies. The Peace Region Load Shedding and Generation Shedding Remedial Action Scheme (RAS) are relied on to address these overload and voltage stability concerns.

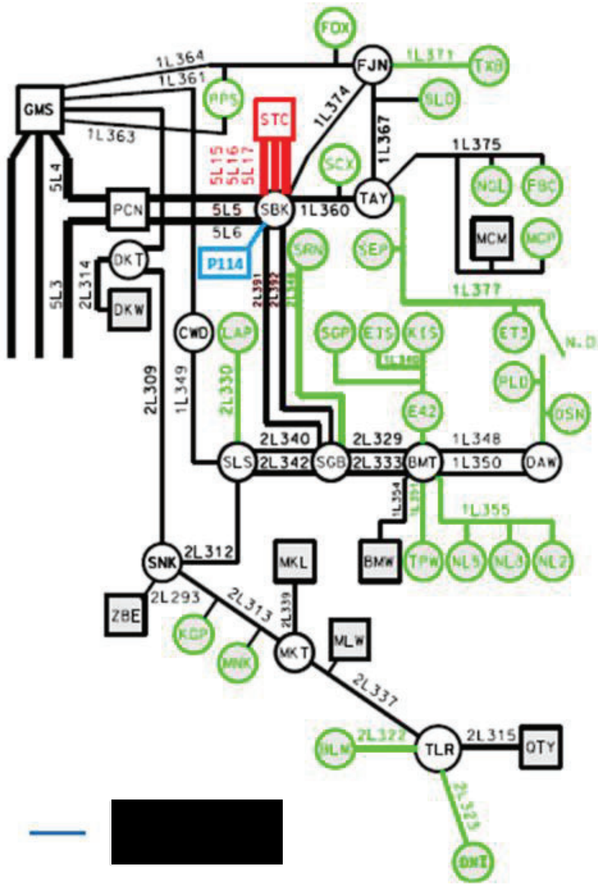

Figure 1-1: Peace Region 500 kV and 138/230 kV Transmission System Diagram.

The Peace Region is a generation-rich area, accounting for over one-third of BCH's total installed capacity. Major generating facilities in the region include the G.M. Shrum Generating Station (GMS), the Peace Canyon Generating Station (PCN), and the recently completed Site C Generating Station (STC), which together provide a total installed capacity of 4,886 MW. In addition to these, several independent power producers are already in service. Furthermore, two new wind farms—[redacted] and [redacted]—each with an installed capacity of 200 MW, are set to be added to the as earlier queued IRs. Customer's system topology behind the Point of Interconnection is provided in the Appendix, Figure A-1.

2 Purpose and Scopes of Study

This Feasibility Study (FeS) 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 FeS is performed individually for each of the participating projects in the Competitive Electricity Acquisition Process (CEAP) 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 generation project proceeds further.

Please note that, due to the compressed study timeline for CEAP 2025 FeS, 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 (FeS) 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: September 22, 2025.
- BC Hydro Operating Order 5T-10, Ratings for All Transmission Circuits 60 kV or Higher, September 17, 2025.
- BC Hydro Operating Order 5T-14, Ratings for All Transmission and Distribution Transformer, September 22, 2025.
- BC Hydro System Operating Order 7T-22 System Voltage Control, October 07, 2025.

4 Assumptions and Conditions

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

The power flow study cases used in this FeS are established based upon the BCH'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 Output (MPO) unless otherwise specified.

2) For purposes of performing this study, approximately 689 MW injection at the POI is achievable and used based on proponent's total installed capacity of 704 MW.

3) [redacted] and [redacted] [redacted]—each with an installed capacity of 200 MW, are set to be added to the region as earlier queue IRs and assumed to be in-service.

5 System Studies and Results

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 requirements based on steady-state performance analysis.

The study focuses on the base scenario — 31HW/32HS/32LS system conditions. These base cases were prepared based on factors such as load conditions, seasonal variation in ambient temperatures, and generation patterns that stress the transmission system.

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

5.1.1 Thermal Overload Analysis

For all the studied load conditions (31HW, 32HS, 32LS), there is no thermal overload identified under system normal condition (P0).

The study finds that the [redacted] Project causes thermal overloads on bulk 500 kV and regional transmission lines and transformers under single contingencies or circuit breaker related P1 and P2 events. Refer to Appendix, Table B-1 for details on facility loadings. The summary of transmission facility overloads is shown in Table 5-1.

Table 5-1: Summary of Thermal Overload Analysis.

Case	Major Contingencies		Branch Loading		
	Category	Description	Branch	Load MVA	Loading %
31HW	P1	SBK T21 OOS	SBK T22	806.4	113
32HS	P1	5L3 OOS	5L1 5L2 5L4	2406.3 2448.8 2458.8	124 128 107
	P1	5L4 OOS	5L3	2386.3	125
			2L308	461.3	108
	P1	SBK T21 OOS	SBK T22	805.7	134
	P2	1L361, GMS T12, GMS T14 OOS	GMS T13	302.3	101
32LS	P1	5L3 OOS	5L1 5L2 5L4	2474.9 2518.7 2556.3	127 132 111
	P1	5L4 OOS	5L3	2487.5	131
			2L308	489.5	115
	P1	SBK T21 OOS	SBK T22	868.5	145
			2L308	434.9	102
	P2	1L361, GMS T12, GMS T14 OOS	GMS T13	333.5	111
	P2	1L364, GMS T11, GMS T13 OOS	GMS T14	313.8	105

When the dispatchable generation in the Peace Region are set to their Maximum Plant Output (MPO) and intermittent generations of Peace and North Coast are set to Effective Load Carrying Capacity (ELCC), thermal overloads occur on some bulk 500 kV transmission lines under contingency conditions.

To address the overload issues in the Peace Region transmission system during contingencies, the new [redacted] Project is required to participate in the existing GMS Area Gen-Shedding RAS. BC Hydro will develop the details of the RAS to address system constraints during the System Impact Study (SIS) stage if needed.

5.1.2 Steady-State Voltage Analysis

For all the studied load conditions (31HW, 32HS, 32LS), the voltage performance under system normal (P0) and contingency conditions (P1 and P2) remains within acceptable limits. The summary of the study results is provided in the Appendix, Table B-2.

5.1.3 Reactive Power Capability Evaluation

The BCH TIR requires IBR power plants 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. This translates to a minimum reactive power range of +/-232.32 MVAr at the high side of the main power transformer.

Based on the IC-submitted PSS/E model data, the proposed [redacted] Project does not meet the reactive power capability requirement above. Installation of minimum of 30 MVAr shunt compensation is required at the IC's facility to meet the requirement. This requirement needs to be addressed if the project proceeds to the next stage of the interconnection process.

In addition, according to the IC-provided reactive capability data, the proposed solar inverter would provide +/-2.64 MVAr per inverter for reactive capability at the zero MW output if the inverter's "reactive power at zero output" 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

The IC is required to install anti-islanding protection within its facility to disconnect the IC's solar farm 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.

5.2 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 (SIS) stage if needed.

5.3 Stations Requirements

The station upgrade scope at the POI is as follows:

- Install one new outdoor 230 kV circuit breaker (2CB11) rated at 3000 A continuous current, 40 kA interrupting rating, 950 kV BIL along with associated motorised disconnects (2D2CB11) rated 3000 A.

- Install a new 230 kV line terminal (2LXX3-[redacted] Project) with associated motorised disconnect switches (2D11) rated 3000 A, Surge Arrester (2SA11) and one 230 kV Capacitor Voltage Transformer (2CVT11).
- Install associated P&C equipment, station service and other equipment in the existing control building.
- Other associated station works.
- Refer to the one-line diagram in the Appendix, Figure C-1 for details.

5.4 Transmission Line Requirements

No transmission line upgrade has been identified 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] Project and its facilities to the BCH Transmission System at the POI, this Feasibility Study (FeS) has identified the following conclusions and requirements:

1. A new 230 kV line position is required at the POI, to facilitate the interconnection of [redacted] Project. The interconnection line, to be built by the IC, is temporarily referred to as 2LXX3. The temporary line designation will be replaced by a permanent one at a later stage of the interconnection process. At the POI, the new line terminal will be installed with associated motorised disconnect switches, surge arrester and capacitor voltage transformer. BCH will also install a new circuit breaker with associated motorised disconnect switches. These facilities are installed to isolate the IC's facilities from the BCH system.

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

3. The connection of [redacted] Project could exacerbate the pre-existing thermal overloads (and/or transient stability) issues on BCH's 500 kV and regional transmission system under single contingencies or circuit breaker related contingencies. To address these issues, the new [redacted] Project is required to participate in the Generation Runback or Shedding Remedial Action Scheme (RAS) to secure the system. The RAS function scope will be specified in the System Impact Study (SIS).

4. [redacted] Project is required to install anti-islanding protection within its facility to disconnect the IC's solar farm 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. The [redacted] Project 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. The [redacted] Project does not meet the reactive power capability requirement above. Installation of minimum of 30 MVAr shunt

compensation is required at the IC’s facility to meet the requirement. This requirement needs to be addressed if the project proceeds to the next stage of the interconnection process.

6. The “Reactive Power at Night” function [or “Reactive Power at Zero Output”] for the proposed solar inverter is required so that each inverter can provide reactive power capability at zero MW output including during nighttime.

Appendix A

Schematic Diagram of IC's Project

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

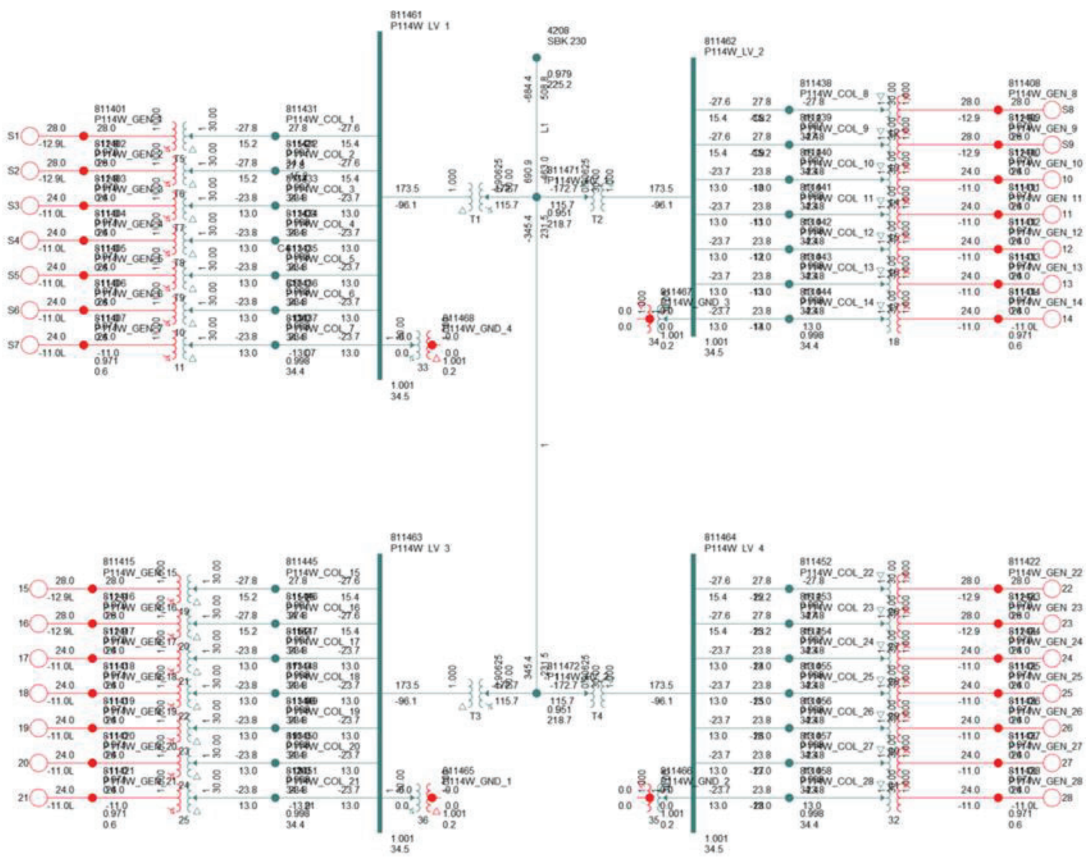

Figure A-1: [redacted] Project Plant Schematic Diagram.

Appendix B
Power Flow Study Results

Table B-1 shows the details of facility loadings under system normal and contingency conditions.

Table B-1: Facility Loadings.

Case	Major Contingencies		Branch Loading		
	Category	Description	Branch	Load MVA	Loading %
31HW	P0	System Normal	5L3	1642.1	63
			2L392	151.7	38
			SBK T21	436.5	61
			1L374	95.8	56
			GMS T14	149.1	42
			2L308	346.5	64
	P1	SBK T21 OOS	SBK T22	806.4	**113**
			2L308	393.2	73
			GMS T13	173.2	49
32HS	P0	System Normal	5L3	1669.6	88
			2L392	165.3	41
			SBK T21	436.2	73
			1L374	72.1	52
			GMS T14	156.8	52
			2L308	361.6	85
	P1	5L3 OOS	5L1 5L2 5L4	2406.3 2448.8 2458.8	**124** **128** **107**
			GMS T13	164.8	55
			2L308	377.0	88
	P1	5L4 OOS	5L3	2386.3	**125**
			1L374	100.9	73
			GMS T13	208.4	69
			2L308	461.3	**108**
			2L309	327.9	77
	P1	SBK T21 OOS	SBK T22	805.7	**134**
			GMS T13	181.0	60
			2L308	408.2	96
			2L309	272.4	64
	P2	1L361, GMS T12, GMS T14 OOS	GMS T13	302.3	**101**
			SBK T22	473.0	79
			2L308	349.2	82
32LS	P0	System Normal	5L3	1721.0	90
			2L392	185.8	46
			SBK T21	469.9	78
			1L374	58.9	43

			GMS T14	172.4	57
			2L308	384.7	90
	P1	5L3 OOS	5L1 5L2 5L4	2474.9 2518.7 2556.3	**127** **132** **111**
			SBK T22	455.7	76
			2L308	400.3	94
	P1	5L4 OOS	5L3	2487.5	**131**
			1L374	90.0	65
			GMS T13	227.4	76
			2L308	489.5	**115**
			2L309	357.5	84
	P1	SBK T21 OOS	SBK T22	868.5	**145**
			GMS T13	198.8	66
			2L308	434.9	**102**
			2L309	300.2	70
	P2	1L361, GMS T12, GMS T14 OOS	GMS T13	333.5	**111**
			SBK T22	511.2	85
			2L308	371.7	87
	P2	1L364, GMS T11, GMS T13 OOS	GMS T14	313.8	**105**
			SBK T22	486.2	81
			2L308	352.3	82

Table B-2 shows the details of steady-state voltage study results under system normal and contingency conditions.

Table B-2: Steady-State Voltage Analysis

Case	Major Contingencies		Bus Voltages (PU)		
	Category	Description	SBK 500	SBK 230	SBK 138
31HW	P0	System Normal	1.027	1.019	1.023
	P1	SBK T21 OOS	1.027	1.016	1.022
32HS	P0	System Normal	1.028	1.019	1.028
	P1	5L3 OOS	1.020	1.017	1.021
	P1	5L4 OOS	1.022	1.018	1.024
	P1	SBK T21 OOS	1.028	1.016	1.027
	P2	1L361, GMS T12, GMS T14 OOS	1.027	1.018	1.028
32LS	P0	System Normal	1.028	1.019	1.019
	P1	5L3 OOS	1.019	1.016	1.025
	P1	5L4 OOS	1.023	1.018	1.016
	P1	SBK T21 OOS	1.028	1.015	1.019
	P2	1L361, GMS T12, GMS T14 OOS	1.027	1.018	1.020
	P2	1L364, GMS T11, GMS T13 OOS	1.027	1.018	1.015

Appendix C
One-Line Sketch for IC's IR at POI

Figure C-1 shows the Stations Planning one-line sketch for [redacted] Project at Southbank 230 kV substation.

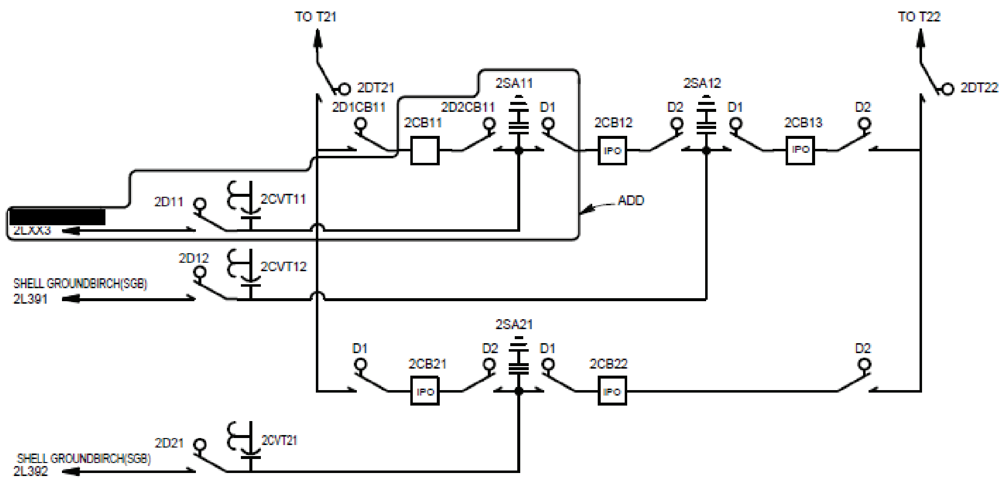

Figure C-1: Stations Planning One-Line Sketch for [redacted] Project at Southbank 230 kV Substation.