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

November 24, 2025

[redacted]

via email: [redacted]

RE: CEAP IR #69 – [redacted] – Interconnection Feasibility Study

Dear [redacted]

Enclosed is the Interconnection Feasibility Study for the proposed Interconnection Request (IR), [redacted], submitted under Attachment M-2: Transmission Service and Interconnection Service Procedures for Competitive Electricity Acquisition Process (CEAP) of the Open Access Transmission Tariff (OATT). This letter provides a non-binding good faith estimate of the cost and time to construct the facilities required to interconnect your project to BC Hydro's Transmission System, being the Network Upgrades, based on the findings of the Interconnection Feasibility Study.

Open Access Transmission Tariff

The OATT defines Network Upgrades as additions, modifications, and upgrades to BC Hydro's Transmission System required at or beyond the Point of Interconnection (POI) to accommodate the interconnection of the Generating Facility to the BC Hydro's Transmission System. Pursuant to the OATT, BC Hydro will design, procure, construct, install, and own the Network Upgrades. While BC Hydro will pay the costs for the Network Upgrades, the Interconnection Customer provides security for such costs.

Interconnection Study Costs

The Interconnection Customer is responsible for paying the full cost of all Interconnection Studies in cash. Interconnection Study costs vary depending on the scope, complexity, and other factors such as whether any scope is shared with another Interconnection Customer (not applicable to this Interconnection Feasibility Study). The deposit amounts specified in the OATT are not proxy Interconnection Study costs. If actual Interconnection Study costs exceed the deposit amount, the Interconnection Customer must pay the remaining balance in cash. Please refer to the answer for question no. 53 in the posted Questions & Answers for 2025 Call for Power for typical study cost ranges.

Cost Estimate

Based on the Interconnection Feasibility Study, the non-binding good faith estimated cost (typical accuracy range of +150%/-50%) for Network Upgrades required to interconnect your project is $128.6 M.

Major Scope of Work Identified:

- Supply and install one 230 kV dead-end pole tap structure on line 2L258
- Supply and install up to three BC Hydro 253 kV disconnect switches and steel pole structures on line 2L258
- Fibre optic cable to be installed along 2L258 between Invermere substation (INV) and the POI tap, approximately 88 km; structure replacement/addition may be required
- Supply and install required Protection, Control and Telecommunications equipment

Exclusions:

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

Key Assumptions:

- Construction by contractor
- 30 months of construction is considered
- No construction during winter season
- Execution of early Engineering and Procurement Agreement
- Full engineering and construction cost of fibre addition to 230kV - 2L258 with length of approximately 88km (INV to IR69 POI tap) are assumed
- Motorized disconnects for the tap were not assumed for cost estimate
- Impact Benefit Agreements with First Nations are not considered

Key Risks:

- Transmission scope may be different than assumed, including number of structure replacements
- Motorized disconnect switches may be required for the tap which may increase Network Upgrade cost estimate and 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 2033 (calendar year). To achieve this timeline, we may need to expedite certain activities, including engineering design and procurement of long-lead equipment.

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

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

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

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

Sincerely,

[redacted]

[redacted]

Manager, Customer Interconnections

BC Hydro

Encl.: CEAP_2025_IR69_[redacted]_Feasibility_Study.pdf

[redacted]

Interconnection Feasibility Study

BC Hydro EGBC Permit to Practice No: 1002449

2025 CEAP IR #69

Prepared for: [redacted]

Prepared by: [redacted]

[redacted]

[redacted]
Engineer in Training, Transmission Planning

Reviewed by: [redacted]

[redacted]
Principal Engineer, Transmission Planning

Accepted by: [redacted]

[redacted]
Manager, Transmission Planning

100-APR-00010
2025 Nov 21

Report Metadata

Header:	2025 CEAP IR #69
Subheader:	Interconnection Feasibility Study
Title:	[redacted]
Subtitle:	2025 CEAP IR #69
Report Number:	100-APR-00010
Revision:	0
Confidentiality:	Public
Date:	2025 Nov 21
Volume:	1 of 1
Prepared for:	[redacted]
Prepared by:	[redacted]
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Checked by:	[redacted]
Title:	Consultant, Transmission Planning
Reviewed by:	[redacted]
Title:	Principal Engineer, Transmission Planning
Related Facilities:	2L258 (230kV)
Additional Metadata:	Transmission Planning 2025-094 Filing Subcode 1350

Revisions

Revision	Date	Description
0	2025 Nov	Initial release

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Contributors

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The entire report except those listed below	Transcription Planning

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Principal Engineer, Transmission Planning

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Section:	**Discipline:**
5.2, 5.3	Substations Growth and Sustainment

Contributed by:

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Sr. Engineer, Substation Growth and Sustainment

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Section:	**Discipline:**
5.4	Transmission Lines Engineering

Contributed by:

[redacted]

[redacted]

Sr. Engineer, Transmission Lines Engineering

[redacted]

Executive Summary

[redacted] [redacted] [redacted] the Interconnection Customer (IC), requests to interconnect its [redacted] (2025 CEAP IR# 69) to the BC Hydro (BCH) system. [redacted] [redacted] [redacted] includes sixty (60) [redacted] inverters, adding a total installed capacity of 190.1 with a maximum power injection of 182.7 MW into the BCH system. The IC proposed Point of Interconnection (POI) is on 230 kV transmission line 2L258 Cranbrook Substation (CBK) - Invermere Substation (INV), approximately 35.5 km from CBK. The IC owned station is connected through an IC owned 1.3 km 230 kV transmission line to the POI. The IC's proposed project's Commercial Operation Date (COD) is October 1, 2029.

To interconnect [redacted] and its facilities to the BCH transmission system at the proposed POI, this Feasibility Study (FeS) has identified the following conclusions and requirements:

1. A 230 kV transmission tap connection on 2L258 proposed by the IC is acceptable to interconnect the customer's generating project to the BCH system.
2. The connection of [redacted] does not cause any performance violation (i.e., thermal overload, voltage performance violation or voltage stability concern) under system normal conditions and various system contingencies.
3. The [redacted] is not allowed to operate in an island with BCH loads. An anti-islanding transfer trip scheme is required to isolate the solar farm to avoid potential islanding operations with BCH loads.
4. The [redacted] is required to have the dynamic reactive power capability at a minimum of +/- 33% of its maximum power output at the high voltage side of the IC's switchyard over the full MW operating range, per BCH's Technical Interconnection Requirements (TIR) Section 6.4.2.
5. The "Q Power at Night" function 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 “Assumptions and Conditions”, 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 FeS 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
CBK	Cranbrook Substation
CEAP	Competitive Electricity Acquisition Process
COD	Commercial Operation Date
DS	Disconnect Switch
ERIS	Energy Resource Interconnection Service
FeS	Feasibility Study
HS	Heavy Summer
HW	Heavy Winter
IC	Interconnection Customer
IPP	Independent Power Producer
IR	Interconnection Request
LS	Light Summer
NERC	North American Electric Reliability Corporation
NRIS	Network Resource Interconnection Service
OATT	Open Access Transmission Tariff
OOS	Out of Service
POI	Point of Interconnection
PU	Per Unit
PV	Photovoltaic
SIE	South Interior East
SIS	System Impact Study
TIR	BC Hydro “60 KV to 500 kV Technical Interconnection Requirements for Power Generators”
TVC	Transmission Voltage Customer
WECC	Western Electricity Coordinating Council
YG	Solidly Grounded Wye
YZG	Impedance Grounded Wye

1 Introduction

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

Table 1-1 Summary of Project Information

Project Name	[redacted]	
Name of Interconnection Customer (IC)	[redacted]	
Point of Interconnection (POI)	A Line Tap on 2L258, at 35.5 km from Cranbrook substation	
IC's Proposed COD	1st October 2029	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	182.7 (Summer)	182.7 (Winter)
Number of Inverters	60 PV Inverters	
Plant Fuel	Solar	

[redacted] the Interconnection Customer (IC), requests to interconnect its [redacted] (2025 CEAP IR #69) to the BC Hydro (BCH) system. [redacted] includes 60 photovoltaic (PV) inverters, adding a total installed capacity of 190.1 with a maximum power injection of 182.7 MW into the BCH system. The IC proposed point of Interconnection (POI) is on 230 kV transmission line 2L258 Cranbrook Substation (CBK) – Invermere Substation (INV), approximately 35.5 km from CBK. The IC's proposed commercial operation date for the project is October 1, 2029.

In the [redacted], there are 60 [redacted] Inverters, each rated at 3.6 MVA/3.17 MW, 630 V. Each PV inverter is connected to a 3.6 MVA 0.63/34.5 kV wye/delta step-up transformer. The total power from all the inverters is collected via six 34.5 kV collector feeders with 3 feeders connected to each of two 34.5 kV collector buses in the customer substation, then stepped up to 230 kV via two 250 MVA, 34.5/230 kV YZG/YG main transformers, one connected to each 34.5 kV collector bus. The IC's substation is connected to the POI in the BCH system via a customer owned 1.3 km 230 kV transmission line. Refer to Appendix A for single line diagram of the project.

Figure 1-1 illustrates the 230/66 kV system in the western portion of the South Interior East (SIE) area supplying the Cranbrook area and the lower Columbia Valley in which the [redacted] is located including its interconnection to circuit 2L258. Cranbrook Substation (CBK) is the major BCH transmission system substation in the SIE area and has two 500/230 kV transformers and two 230/66 kV transformers. Circuit 2L258 feeds from CBK and it supplies the Columbia Valley area. Four 66 kV transmission lines are also supplied by CBK and they supply the local Cranbrook area: 60L283 CBK - Marysville Substation (MVL), 60L299 CBK - Joseph Creek Substation (JOE), 60L284 CBK - Moyie Substation (MYE) and 60L289 CBK - Aberfeldie New Generating Station (ABN).

There are 60kV network upgrades in the study area. The relevant network upgrades being planned in the study region are included in Section 4 "Assumptions and Conditions".

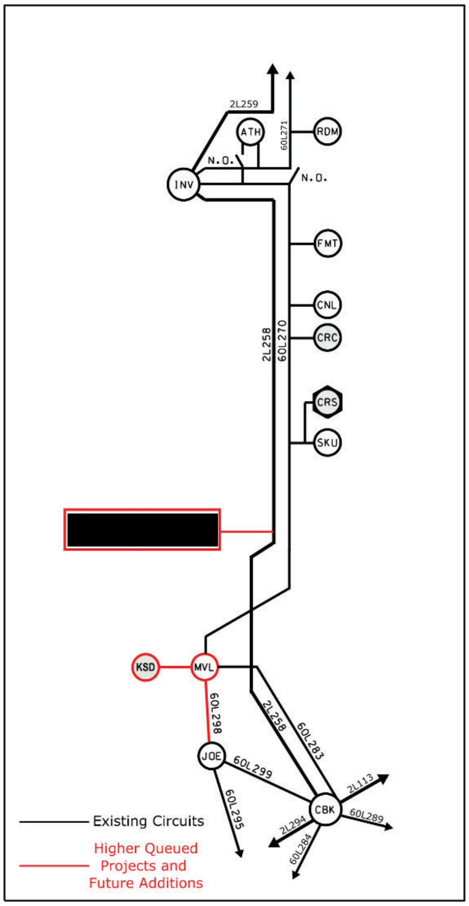

Figure 1-1: Western SIE Area 230/66 kV Transmission System Diagram – 2029/30

2 Purpose and Scopes of Study

This 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 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 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 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 Technical Interconnection Requirements (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 FeS 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 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 (network upgrades in the 60 kV system) 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.

- The study area includes the Columbia Valley area and the Cranbrook area.
- The regional generation is dispatched in the patterns that most stress the transmission system in the study area. In these patterns, the regional generations are typically set to their maximum power outputs unless otherwise specified.

5 System Studies and Results

A tap connection to circuit 2L258 has been accepted for the IC's system interconnection purposes. Per the requirement of BCH system operation order, high velocity interrupters should be required for the 230 kV Air-Break Disconnect Switch (DS) at the tap location to drop customer's 1.3 km 230 kV tap line. Subject to a further review, motorized DS at the tap location with remote control shall be considered to meet personnel safety requirements when isolating the IC's tap line during outages. Detailed requirement at the tap location will be further investigated in the SIS stage if the IC proceeds.

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 reinforcement requirement based on steady state performance analysis.

The studies have been conducted with the focus on the 2030 light summer (LS) system condition, taking into considerations of load conditions, seasonal variation in ambient temperatures, and generation patterns that stress the transmission system. The 2029 heavy winter (HW) and 2030 heavy summer (HS) cases are also checked at a high level to capture any performance violations under high load conditions.

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 Branch Loading Analysis

Appendix B shows a summary of branch loading analysis under system normal and single contingencies (P1) for various load conditions.

For all the studied load conditions (30LS, 30HS, 29HW), there is no branch overload identified under system normal condition (P0) and selected single contingency conditions (P1) contingencies.

5.1.2 Steady-State Voltage Analysis

For all the studied load conditions (30LS, 30HS, 29HW), the voltage performance under system normal condition (P0) and selected single contingency conditions (P1) is acceptable. Appendix B shows a summery of steady-state voltage performance under various system conditions and contingencies.

5.1.3 Reactive Power Capability Evaluation

The BCH TIR requires inverter-based resource generators have the dynamic reactive power capability at a minimum of +/- 33% of its maximum power output 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 BCH reactive capability requirement at the plant's maximum MW output, which is subjected to further verification in the next stage of the interconnection process.

In addition, according to the IC-provided reactive capability data, the proposed project would provide +2.1 MVAR to -2.1 MVAR reactive capability at the zero MW output if the inverter's "Q Power at Night" 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 allowed to operate in an island with BCH loads. An Anti-islanding transfer trip scheme is required to isolate the [redacted] to avoid potential islanding operations with BCH loads.

5.2 Fault Analysis

The short circuit analysis in the FeS 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 SIS stage if needed.

5.3 Stations Requirements

As the IC proposed POI of the [redacted] is a tap connection on 230 kV transmission line 2L258, about 35.5 km from Cranbrook substation (CBK). No station work is required.

5.4 Transmission Line Requirements

The Transmission Lines Engineering upgrade scope is as follows.

- At the Point of Interconnection (POI), ~35.5km from CBK on 2L258, BCH will design and build the tap that may include a non-standard tap structure and up to three non-standard switches and structures, two structures adjacent to the switch structures converted to dead-ends, and a dead-end structure as the demarcation point between BC Hydro and the customer. Up to three 253kV rated motorized disconnect switches may be installed to isolate/ sectionalize the IC's facilities and BC Hydro's system. Additional Right-of-Way (ROW) may be required to accommodate the tap.
- Fibre optic cable to be installed along 2L258 between INV and IR69 POI tap, approximately 88 km. Structure replacement/addition may be required.

6 Cost Estimate and Schedule

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

7 Conclusions

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

1. Upon a collaborative decision from the BCH study team, a tap connection on 2L258 proposed by the IC is acceptable to interconnect the customer's generating project to the BCH system.

   Potential tap configuration requirements:

   Per the requirement of BC Hydro System Operation Order (SOO), high velocity interrupters are required for the 230 kV Air-Break Disconnect Switch (DS) at the tap location to drop customer's 1.3 km 230 kV tap line. Subject to a further review, motorized DS at the tap location with remote control will be installed to meet personnel safety requirements when isolating the IC's tap line during outages. Detailed requirement at the tap location will be further investigated in the SIS stage if the IC proceeds.

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

3. The [redacted] is not allowed to operate in an island with BCH loads. An Anti-islanding transfer trip scheme is required to isolate the Solar farm to avoid potential islanding operations with BCH loads.

4. The [redacted] is required to have the dynamic reactive power capability at a minimum of +/- 33% of its maximum power output at the high voltage side of the IC's switchyard over the full MW operating range, per BCH's TIR Section 6.4.2.

5. The "Q Power at Night" function 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

Plant Single Line Diagram Used for Power Flow Study

Figure A-1 shows [redacted] single line diagram used for the power flow study.

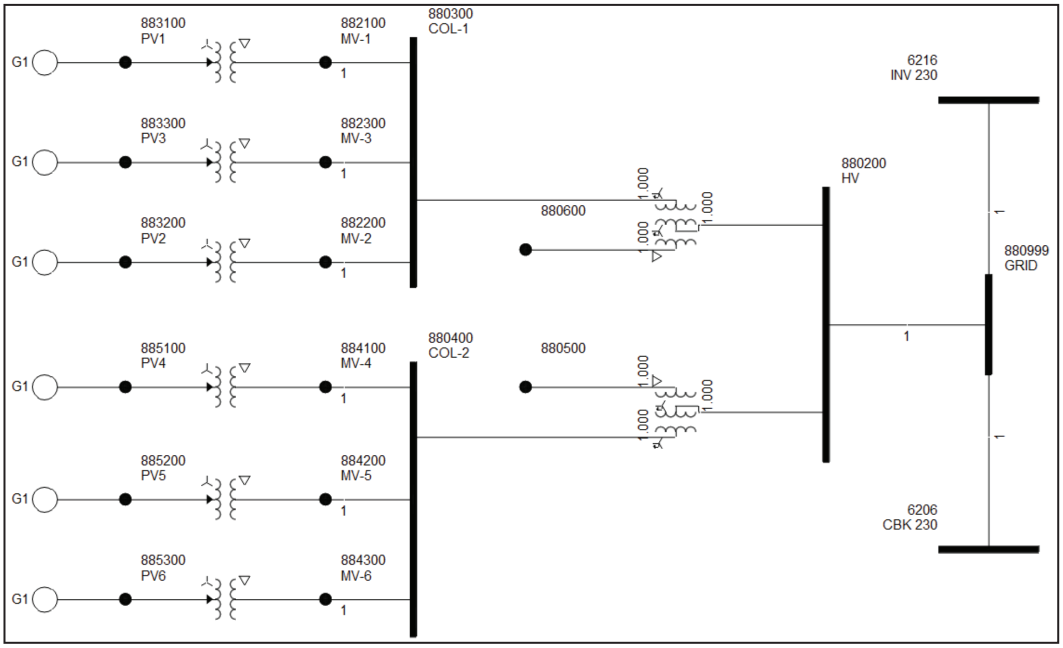

Figure A-1: [redacted] Single Line Diagram for Power Flow Study.

As seen in the diagram, The IC’s plant consists of the following major facilities: 60 proposed 3.17 MW, 630 V solar generators, each with a 3.6 MVA, 0.63/34.5 kV step-up transformer; 6 – 34.5 kV collector feeders, 3 feeders supplying each of the 2 – 34.5 kV collector buses in the customer’s 34.5/230 kV substation; 2 – 250 MVA, 34.5/230 kV main transformers; and a 1.3 km, 230 kV transmission line connecting the IC’s substation to the POI in 2L258.

Appendix B

Power Flow Study Results

Table B-1: Summary of Branch Loading Study Results

Case	IPP's Generator Output	Contingency Identified		Branch Loading			
		Category	Description	2L258 (CBK-POI)	2L258 (POI-INV)	CBK T3	CBK T7
Winter Rating				318.7 MVA	318.7 MVA	714.0 MVA	199.5 MVA
29HW	190.1 MW	P0	System Normal	34%	30%	5%	16%
		P1	CBK T2 & CBK T6 OOS[1]	31%	31%	9%	31%
		P2	2L258 open at CBK	N/A	N/A	N/A	N/A
Summer Rating				318.7 MVA	318.7 MVA	600.0 MVA	168.0 MVA
30HS	190.1 MW	P0	System Normal	49%	16%	9%	13%
		P1	CBK T2 & CBK T6 OOS[1]	48%	16%	17%	24%
		P2	2L258 open at CBK	N/A	N/A	N/A	N/A
30LS	190.1 MW	P0	System Normal	55%	14%	11%	5%
		P1	CBK T2 & CBK T6 OOS[1]	54%	14%	21%	11%
		P2	2L258 open at CBK	N/A	N/A	N/A	N/A
Note 1: CBK T2 and CBK T6 are in the same protection zone.							

Table B-2: Summary of Steady-State Voltage Study Results

Case	IPP's Generator Output	Contingency		Bus Voltage (PU)		
		Category	Description	CBK 230	POI	INV 230
29HW	190.1 MW	P0	System Normal	1.02	1.00	1.01
		P1	CBK T2 & CBK T6 OOS[1]	1.01	1.00	1.01
		P2	2L258 open at CBK	N/A	N/A	N/A
30HS	190.1 MW	P0	System Normal	1.01	1.00	1.03
		P1	CBK T2 & CBK T6 OOS[1]	1.01	1.00	1.03
		P2	2L258 open at CBK	N/A	N/A	N/A
30LS	190.1 MW	P0	System Normal	1.02	1.00	1.04
		P1	CBK T2 & CBK T6 OOS[1]	1.02	1.00	1.04
		P2	2L258 open at CBK	N/A	N/A	N/A
Note 1: CBK T2 and CBK T6 are in the same protection zone.						