BC Hydro
Power smart

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

December 17, 2025

[redacted]

via email: [redacted]

RE: CEAP IR #52 – [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 $358.4M.

Major Scope of Work Identified:

- Thermally upgrade the overhead circuit 1L203 section between [redacted] tap and Savona substation (SVA) including structure replacements and installations as required
- Thermally upgrade the overhead circuit 1L205 section between Highland substation (HLD) and SVA including structure replacements and installations as required

- Supply and install required Protection, Control and Telecommunications equipment

Exclusions:

- GST
- Permits
- Right-of-Way & property costs
- Interconnection configuration at KCH is determined by third-party entity [redacted], and not included

Key Assumptions:

- Construction by contractor
- 24 months of construction is considered
- No construction during winter season
- Execution of early Engineering and Procurement Agreement
- 90% of Transmssion line structures on both 1L203 (SVA to [redacted] Tap) and 1L205 (SVA to HLD) to be replaced
- 100% of Transmission Lines 1L203 (SVA to [redacted] Tap) and 1L205 (SVA to HLD) to be reconductored, with assemblies replaced
- A certificate of public convenience and necessity (CPCN) requirement will be exempt
- Impact Benefit Agreements with First Nations are not considered

Key Risks:

- Transmission scope may be different than assumed, including number of structure replacements
- 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
- If a CPCN is required for the project, it may impact project cost and schedule risks

Indirect Interconnection

Your IR involves an indirect interconnection to the BC Hydro Transmission System. Under the OATT Attachment M-1: Standard Generator Interconnection Procedures (SGIP) and the Standard Generator Interconnection Agreement (SGIA), the party executing the SGIA must be the owner of the Interconnection Customer Interconnection Facilities up to the Point of Interconnection. Depending on the scope of required Network Upgrades, this execution may occur years before the Commercial Operation Date.

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.

It is also assumed that there will be some telecom telecommunications system requirements and associated costs that fall under the Interconnection Customer Interconnection Facilities (ICIF) that is not included in the estimated cost for Network Upgrades.

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]

Manager, Customer Interconnections

BC Hydro

Encl.: CEAP_2025_IR52_[redacted]_Feasibility_Study.pdf

[redacted]

Interconnection Feasibility Study

BC Hydro EGBC Permit to Practice No: 1002449

2025 CEAP IR # 52

Prepared for: [redacted]

Prepared by: [redacted] [redacted]

Engineer, Transmission Planning

Reviewed by: [redacted]

Principal Engineer, Transmission Planning

Accepted by: [redacted]

Manager, Transmission Planning

Report Metadata

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Prepared for:	[redacted]
Prepared by:	[redacted]
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Title:	Principal Engineer, Transmission Planning
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Revision	Date	Description
0	2025 Nov	Initial release

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Sr. Engineer, Transmission Lines Engineering

Executive Summary

[redacted] the interconnection customer (IC), requests to interconnect its [redacted] (2025 CEAP IR # 52) to the BC Hydro (BCH) system. [redacted] has sixteen (16) [redacted] solar and battery inverters rated 2.82 MW, providing 44 MW of supply into the BC Hydro system. The Point of Interconnection (POI) is a 138kV bus at Kwoiek Creek Generating Station (KCH), owned by [redacted]. The IC's proposed commercial operation date (COD) is December 15, 2027.

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

1. The IC proposed POI is a 138kV bus at KCH. This is an indirect interconnection to Highland Substation (HLD) via 1L57. The interconnection configuration at the POI will be determined by KCRLP.

2. The connection of [redacted] causes transmission circuits thermal violations under system normal conditions and the proposed system upgrades are as follows:

   a. Re-conductoring 1L203 section between [redacted] Tap and Savona Substation (SVA) (approximately 25 km) to a minimum summer rating of 788 Ampere;

   b. Re-conductoring 1L205 HLD-SVA (approximately 41.8 km) to a minimum summer rating of 575 Ampere.

3. The connection of [redacted] causes multiple transmission circuits thermal violations under various single contingency conditions such as loss of 1L243, 1L205, 1L203, Breaker failures at HLD, SVA, NIC, etc. To resolve the post contingency overloading concerns, gen-shedding at the project site is required. Further investigation into gen-shedding details will occur in a later System Impact Study (SIS) stage if the project proceeds.

4. 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 including zero MW output, per BC Hydro’s TIR Section 6.4.2.

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

[redacted] [redacted]

CEAP Competitive Electricity Acquisition Process

COD Commercial Operation Date

ERIS Energy Resource Interconnection Service

FeS Feasibility Study

HLD Highland Substation

[redacted] [redacted]

IBR Inverter-Based Resources

IC Interconnection Customer

IPP Independent Power Producer

[redacted] [redacted]

KCH Kwoiek Creek Generating Station

[redacted]

[redacted] [redacted]

MPO Maximum Power Output

NERC North American Electric Reliability Corporation

NRIS Network Resource Interconnection Service

OATT Open Access Transmission Tariff

P52 [redacted]

POI Point of Interconnection

RAS Remedial Action Scheme

[redacted] [redacted] Solar

SIS System Impact Study

SVA Savona Substation

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)	KCH 138 kV bus (owned by [redacted] IPP)	
IC's Proposed COD	15th December 2027	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	44 (Summer)	44 (Winter)
Number of Inverters	16 x 2.82 MW Inverters	
Plant Fuel	Solar	

[redacted] the interconnection customer (IC), requests to interconnect its [redacted] (2025 CEAP IR # 52) to the BC Hydro system. The [redacted] has sixteen (16) [redacted] solar and battery inverters rated 2.82 MW, providing 44 MW of supply into the BC Hydro system. The Point of Interconnection (POI) is a 138kV bus at Kwoiek Creek Generating Station (KCH), owned by [redacted]. The IC's proposed commercial operation date (COD) is December 15, 2027.

Figure 1-1 shows part of the South Interior West region 138/230 kV transmission system diagram with the addition of the [redacted] (P52). The Point of Interconnection (POI) of the [redacted] is a 138 kV bus at KCH. KCH is connected through the 138 kV transmission line 1L57 to Highland Substation (HLD), which is connected to the rest of the BC Hydro Transmission System by 138 kV lines 1L203, 1L205, and 1L243. There are three independent power producers (IPPs) in the local area: Kwoiek Creek Generating Station (KCH), Merritt Green Energy Project Generating Station (MIG), and quA-ymn Solar farm (QYS). Figure 1-1 also includes the following future IPPs that will be connecting to the system: [redacted]

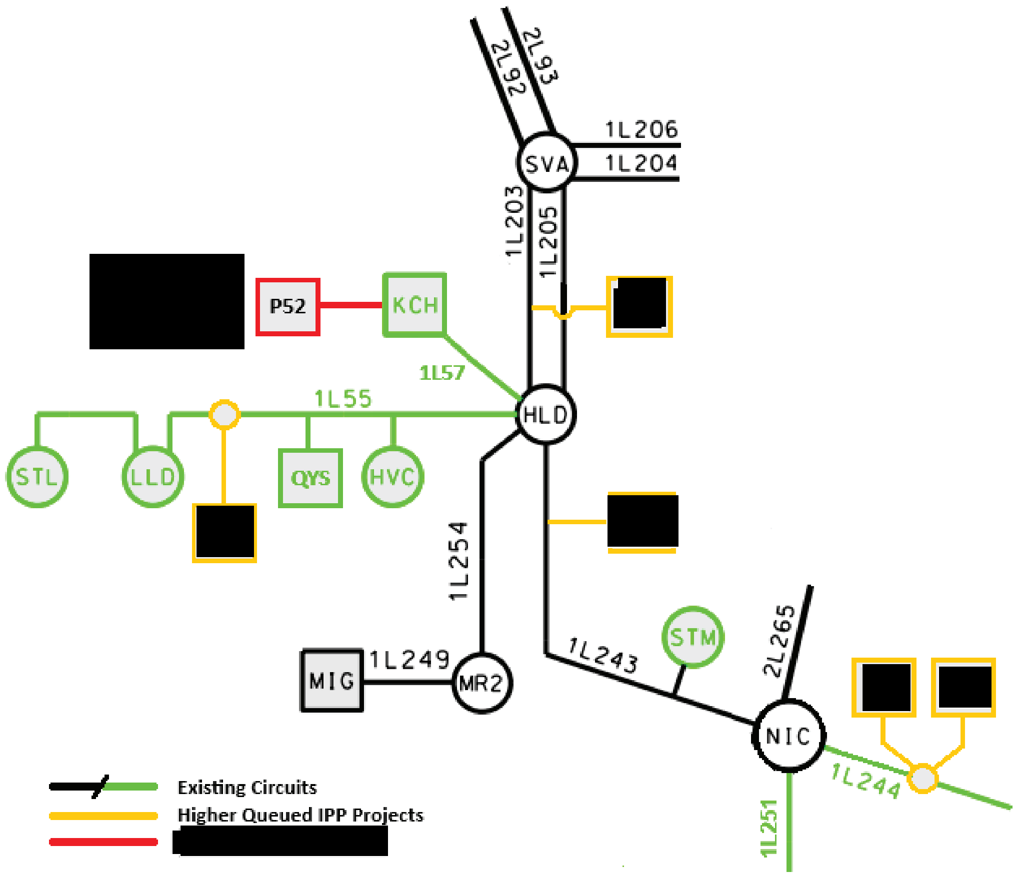

Figure 1-1: Proposed [redacted] (P52) and the BC Hydro Local Area Transmission System

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, Sept 19, 2023.

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 regional generations are set to maximum values to most stress the transmission system in the study area but not overload transmission elements before the interconnection of [redacted]
2) Loads on line 1L55 are modeled to the levels of reflecting TVC real-time operating scenarios in the study cases for various load scenarios, such as light summer, heavy summer and heavy winter.
3) For a higher queued interconnection project, 1L243 is required to be reconductored to meet the supply demands.
4) 2024 CEAP projects which have higher queue positions in the study area are included in the study.

5 System Studies and Results

Based upon the IC's submitted information and the area system conditions assumed for study purposes, a connection to a 138kV bus at KCH is assumed acceptable to interconnect the IC's generating project to the BCH system. KCH is a privately owned station and the interconnection configuration at the POI will be determined by [redacted].

5.1 Power Flow Study Results

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

Steady-state power flow studies have been conducted with the focus on the 31HW and 32HS system conditions that include all the higher-queued future generating projects in the region ([redacted]). A 35LS case was also studied with load and generation values set to the worst-case scenarios anticipated between the [redacted] COD and 2035. 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

Table B-1 in Appendix B shows a summary of branch loading analysis under system normal and single contingencies (P1, P2) for various load conditions.

For the studied load condition 31HW, there are no new branch overloads under system normal condition (P0).

For the studied load conditions 32HS and 35LS there are branch overloads up to 104% on 1L203 SHQ-SVA and 110% on 1L205 identified under system normal condition (P0). These overloads will be addressed by re-conductoring the lines to the following ratings:

- Re-conductoring 1L203 section between [redacted] Tap and Savona Substation (SVA) (approximately 25 km) to a minimum summer rating of 788 Ampere;
- Re-conductoring 1L205 HLD-SVA (approximately 41.8 km) to a minimum summer rating of 575 Ampere.

Under single contingencies (i.e. 1L203, 1L205, 1L243), the study finds branch overloads on 1L203, 1L205, and 1L243 (MMW-STM and STM-NIC). These overloads will be addressed by generation shedding from the [redacted] project.

5.1.2 Steady-State Voltage Analysis

For the studied load conditions 31HW, 32HS, and 35LS, the voltage performance under system normal condition (P0) and single contingency is acceptable. Table B-2 in Appendix B shows a summary of steady-state voltage performance under various system conditions and contingencies.

5.1.3 Reactive Power Capability Evaluation

The BC Hydro 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.

Based on the PSS/E power flow data submitted by the IC, the proposed generating project would be capable of meeting the BC Hydro's reactive capability requirement at the plant's maximum MW output, which is subjected to further verification in the next stage of interconnection study.

Furthermore, the BCH TIR requires the IC's project to provide sufficient reactive power capability over full MW operating range including at zero MW output level.

The reactive capabilities of the IPP's plant and their adequacy to meet BCH requirements is subject to confirmation in the next stage of studies if this project is selected to move forward in the 2025 CEAP selection process.

5.1.4 Anti-Islanding Requirements

[redacted] is not allowed to operate in an island with BC Hydro load. Anti-islanding protection installed within IC's facility 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 Feasibility Study is based upon the latest BC Hydro system model, which includes the generating facility information and associated impedance data provided by the IC. A more detailed study will be performed at the System Impact Study stage if needed.

5.3 Stations Requirements

The station upgrade scope is as follows:

- At Savona (SVA) substation, upgrade 1L203 line jumper to a minimum 788 A summer rating
- At Highland (HLD) substation, upgrade 1L205 line jumper to a minimum 575 A summer rating

5.4 Transmission Line Requirements

The transmission line upgrade scope is as follows:

- Thermally upgrade the overhead circuit 1L203 (SVA to [redacted] Tap) by changing from the existing "Hawk" ACSR to new "Goose" ACSR (rated at 90°C conductor temperature, summer ambient temperature). Structure replacements may be required.
- Thermally upgrade the overhead circuit 1L205 (SVA to HLD) by changing from the existing "Partridge" ACSR to new "IBIS" ACSR (rated at 90°C conductor temperature, summer ambient temperature). Structure replacements 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 [redacted] and its facilities to the BCH Transmission System at the POI, this Feasibility Study has identified the following conclusions and requirements:

1. The IC proposed POI is a 138kV bus at KCH. This is an indirect interconnection to Highland Substation (HLD) via 1L57. The interconnection configuration at the POI will be determined by [redacted]
2. The connection of [redacted] causes transmission circuits thermal violations under system normal conditions and the proposed system upgrades are as follows:
    a. Re-conductoring 1L203 section between [redacted] Tap and Savona Substation (SVA) (approximately 25 km) to a minimum summer rating of 788 Ampere;
    b. Re-conductoring 1L205 HLD-SVA (approximately 41.8 km) to a minimum summer rating of 575 Ampere.
3. The connection of [redacted] causes multiple transmission circuits thermal violations under various single contingency conditions such as loss of 1L243, 1L205, 1L203, Breaker failures at HLD, SVA NIC etc. To resolve the post contingency overloading concerns, gen-shedding at the project site is required. Further investigation into gen-shedding details will occur in a later System Impact Study (SIS) stage if the project proceeds.
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 including zero MW output, per BC Hydro's TIR Section 6.4.2.

Appendix A
Plant Single Line Diagram Used for Power Flow Study

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

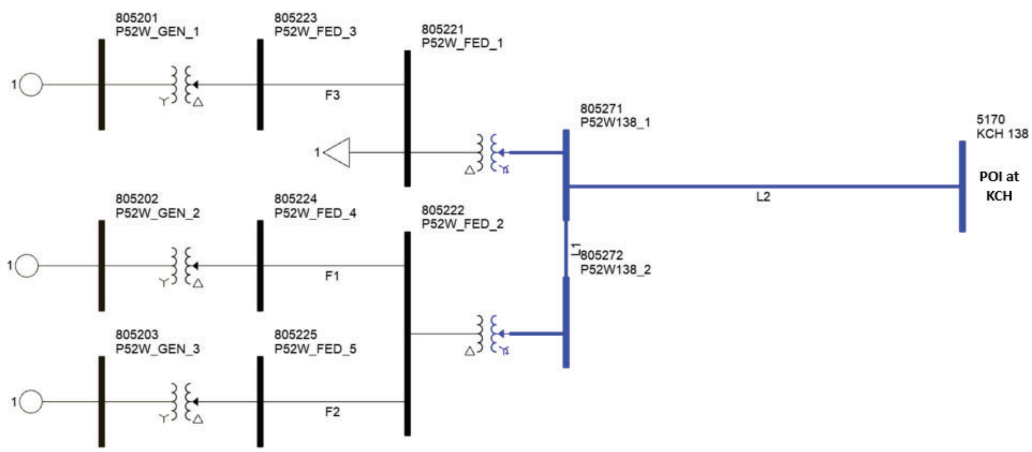

Figure A-1: [redacted] Single Line Diagram for Power Flow Study.

As shown in Figure A-1, [redacted] system includes 3 – 25 kV collector feeders; 1 – 40 MVA, 25/138 kV transformer connecting feeders 1 and 2 to its 138 kV bus; 1 – 25 MVA, 25/138 kV transformer connecting feeder 3 to its 138 kV bus; a 1.0 km, 138 kV transmission line connecting the 2 – 138 kV buses; and a 9.6 km, 138 kV transmission line from the [redacted] project's 138 kV substation to the interconnection point on KCH's 138 kV bus. The feeders respectively connect to 3, 6, and 7 – 0.6 kV, 3.15 MVA/2.82 MW generators, each provided with a 3.15 MVA, 0.6/24.9 kV step-up transformer. The maximum generating capacity is 45.1 MW and the maximum VAR output is +/- 22.6 MVAR.

Appendix B

Power Flow Study Results

Table B-1 Summary of Branch Loading Study Results

Case	IPP's Gen Output (MW)	Contingency Identified		Branch Loading (MVA / %)					
				1L203		1L205	1L243		
		Cate-gory	Description	HLD-[redacted]	[redacted] SVA	HLD-SVA	HLD-[redacted]	[redacted]-STM	STM-NIC
31HW	45.1	P0	System Normal	62.4 32.7 %	167.5 87.6 %	118.4 79.1 %	19.2 6.4 %	130.9 43.5 %	129.6 43.1 %
		P1	1L203 OOS	X	X	175.6 117.4 %	14.7 4.9 %	138 45.9 %	136.7 45.4 %
		P1	1L205 OOS	132.3 69.2 %	239 125 %	X	45.3 15.1 %	173.6 57.7 %	172.5 57.3 %
		P1	1L243 OOS	58.9 30.8 %	164.1 85.8 %	115.2 77 %	X	X	X
		P2	1L203 open at HLD	X	105.3 55.1 %	156.3 104.4 %	24 8 %	155.3 51.6 %	154 51.2 %
		P2	1L203 open at SVA	105.4 55.1 %	X	219.9 147 %	60.7 20.2 %	194.5 64.6 %	193.3 64.3 %
		P2	1L243 open at HLD	58.8 30.8 %	163.9 85.7 %	115 76.8 %	X	140 46.5 %	138.5 46 %
		P2	1L243 open at NIC	128.5 67.2 %	233.4 122.1 %	180.6 120.7 %	135.6 45.1 %	1.7 0.6 %	X
32HS	45.1	P0	System Normal	68.4 39.6 %	173.5 100.4 %	124 104.6 %	18.2 7.2 %	133.4 52.8 %	132.2 52.3 %
		P1	1L203 OOS	X	X	185.3 156.3 %	14.9 5.9 %	142.6 56.4 %	141.5 56 %
		P1	1L205 OOS	141.5 81.9 %	248.7 143.9 %	X	49.1 19.4 %	178 70.4 %	177 70.1 %
		P1	1L243 OOS	66.1 38.3 %	171.5 99.2 %	122.1 103 %	X	X	X
		P2	1L203 open at HLD	X	105.4 61 %	165.6 139.7 %	27.3 10.8 %	160 63.3 %	158.9 62.9 %
		P2	1L203 open at SVA	105.4 61 %	X	229.3 193.4 %	65 25.7 %	199 78.8 %	198.1 78.4 %
		P2	1L243 open at HLD	65.9 38.1 %	171.1 99 %	121.8 102.7 %	X	140.1 55.5 %	138.8 54.9 %
		P2	1L243 open at NIC	135.2 78.2 %	240.6 139.2 %	187.1 157.8 %	135.6 53.7 %	1.6 0.6 %	X
35LS	45.1	P0	System Normal	75.3 43.5 %	179.2 103.7 %	130 109.6 %	118.8 45 %	256.5 97.1 %	257.8 97.6 %
		P1	1L203 OOS	X	X	195.9 165.3 %	130.6 49.4 %	268 101.5 %	269.5 102 %
		P1	1L205 OOS	150.8 87.3 %	258.4 149.5 %	X	165.4 62.6 %	300.2 113.7 %	302.4 114.5 %
		P1	1L243 OOS	135.1 78.2 %	238.7 138.1 %	186.2 157.1 %	X	X	X
		P2	1L203 open at HLD	X	104.1 60.2 %	175.9 148.4 %	148.1 56.1 %	284.4 107.7 %	286.1 108.3 %
		P2	1L203 open at SVA	102.3 59.2 %	X	237.6 200.4 %	186.9 70.8 %	321.2 121.6 %	323.5 122.5 %
		P2	1L243 open at HLD	135.1 78.2 %	238.6 138.1 %	186.1 157 %	X	142 53.8 %	141.7 53.7 %
		P2	1L243 open at NIC	202.9 117.4 %	305.7 176.9 %	249.7 210.6 %	133.7 50.6 %	1.8 0.7 %	X

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

Case	IPP's Generator Output	Contingency		Bus Voltage (PU)		
		Cate-gory	Description	HLD 138	NIC 138	SVA 138
31HW	45.1 MW	P0	System Normal	1.01 PU	1.03 PU	1.01 PU
		P1	1L203 OOS	1.01 PU	1.03 PU	1.02 PU
		P1	1L205 OOS	1.01 PU	1.02 PU	1.02 PU
		P1	1L243 OOS	1.01 PU	1.03 PU	1.01 PU
		P2	1L203 open at HLD	1.01 PU	1.03 PU	1.01 PU
		P2	1L203 open at SVA	1.01 PU	1.02 PU	1.01 PU
		P2	1L243 open at HLD	1.01 PU	1.03 PU	1.01 PU
		P2	1L243 open at NIC	1.01 PU	1.03 PU	1.01 PU
32HS	45.1 MW	P0	System Normal	1.01 PU	1.03 PU	1.01 PU
		P1	1L203 OOS	1.01 PU	1.03 PU	1.02 PU
		P1	1L205 OOS	1.01 PU	1.03 PU	1.02 PU
		P1	1L243 OOS	1.01 PU	1.02 PU	1.01 PU
		P2	1L203 open at HLD	1.01 PU	1.03 PU	1.01 PU
		P2	1L203 open at SVA	1.01 PU	1.02 PU	1.01 PU
		P2	1L243 open at HLD	1.01 PU	1.03 PU	1.01 PU
		P2	1L243 open at NIC	1.01 PU	1.02 PU	1.01 PU
35LS	45.1 MW	P0	System Normal	1 PU	1.02 PU	1.01 PU
		P1	1L203 OOS	1 PU	1.02 PU	1.02 PU
		P1	1L205 OOS	0.99 PU	1.02 PU	1.02 PU
		P1	1L243 OOS	1.01 PU	1.03 PU	1.01 PU
		P2	1L203 open at HLD	1 PU	1.02 PU	1.02 PU
		P2	1L203 open at SVA	1 PU	1.01 PU	1.01 PU
		P2	1L243 open at HLD	1.01 PU	1.02 PU	1.01 PU
		P2	1L243 open at NIC	1 PU	1.03 PU	1 PU