BC Hydro
Power smart

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

November 24, 2025

[redacted]

via email: [redacted]

RE: CEAP IR #53 – [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 $319.5M.

Major Scope of Work Identified:

- Thermally upgrade the overhead circuit 1L203 section between the [redacted] tap and Savona Substation (SVA) including structure replacements and installations as required
- Thermally upgrade the overhead circuit 1L205 section between BC Hydro 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
- Tap configuration on line 1L249, section MIG-MR2, is determined by third-party entity [redacted] not included
  Any upgrades required for the facilities owned by [redacted] will be the responsibility of [redacted]

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 Transmission 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.

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_IR53_[redacted]_Feasibility_Study.pdf

[redacted]

Interconnection Feasibility Study

BC Hydro EGBC Permit to Practice No: 1002449

2025 CEAP IR # 53

Prepared for: [redacted]

Prepared by: [redacted] [redacted]

Engineer, Transmission Planning

Reviewed by: [redacted]

Principal Engineer, Transmission Planning

Accepted by: [redacted]

Manager, Transmission Planning

300-APR-00042
2025 Nov 21

Report Metadata

Header:	[redacted]
Subheader:	Interconnection Feasibility Study
Title:	[redacted]
Subtitle:	2025 CEAP IR # 53
Report Number:	300-APR-00042
Revision:	0
Confidentiality:	Public
Date:	2025 Nov 21
Volume:	1 of 1
Prepared for:	[redacted]
Prepared by:	[redacted]
Title:	Engineer, Transmission Planning
Checked by:	[redacted]
Title:	Consultant, Transmission Planning
Reviewed by:	[redacted]
Title:	Principal Engineer, Transmission Planning
Related Facilities:	1L249
Additional Metadata:	Transmission Planning 2025-083 Filing Subcode 1350

Revisions

Revision	Date	Description
0	2025 Nov	Initial release

Disclaimer of Warranty, Limitation of Liability

This report was prepared solely for internal purposes. All parties other than BC Hydro are third parties.

BC Hydro does not represent, guarantee or warrant to any third party, either expressly or by implication:

any information, product or process disclosed, described or recommended in this report.

BC Hydro does not accept any liability of any kind arising in any way out of the use by a third party of any information, product or process disclosed, described or recommended in this report, nor does BC Hydro accept any liability arising out of reliance by a third party upon any information, statements or recommendations contained in this report. Should third parties use or rely on any information, product or process disclosed, described or recommended in this report, they do so entirely at their own risk.

This report was prepared by the British Columbia Hydro And Power Authority ("BCH") or, as the case may be, on behalf of BCH by persons or entities including, without limitation, persons or entities who are or were employees, agents, consultants, contractors, subcontractors, professional advisers or representatives of, or to, BCH (individually and collectively, "BCH Personnel").

This report is to be read in the context of the methodology, procedures and techniques used, BCH's or BCH's Personnel's assumptions, and the circumstances and constraints under which BCH's mandate to prepare this report was performed. This report is written solely for the purpose expressly stated in this report, and for the sole and exclusive benefit of the person or entity who directly engaged BCH to prepare this report. Accordingly, this report is suitable only for such purpose, and is subject to any changes arising after the date of this report. This report is meant to be read as a whole, and accordingly no section or part of it should be read or relied upon out of context.

Unless otherwise expressly agreed by BCH:

(a) any assumption, data or information (whether embodied in tangible or electronic form) supplied by, or gathered from, any source (including, without limitation, any consultant, contractor or subcontractor, testing laboratory and equipment suppliers, etc.) upon which BCH's opinion or conclusion as set out in this report is based (individually and collectively, "Information") has not been verified by BCH or BCH's Personnel; BCH makes no representation as to its accuracy or completeness and disclaims all liability with respect to the Information;

(b) except as expressly set out in this report, all terms, conditions, warranties, representations and statements (whether express, implied, written, oral, collateral, statutory or otherwise) are excluded to the maximum extent permitted by law and, to the extent they cannot be excluded, BCH disclaims all liability in relation to them to the maximum extent permitted by law;

(c) BCH does not represent or warrant the accuracy, completeness, merchantability, fitness for purpose or usefulness of this report, or any information contained in this report, for use or consideration by any person or entity. In addition, BCH does not accept any liability arising out of reliance by a person or entity on this report, or any information contained in this report, or for any errors or omissions in this report. Any use, reliance or publication by any person or entity of this report or any part of it is at their own risk; and

(d) In no event will BCH or BCH's Personnel be liable to any recipient of this report for any damage, loss, cost, expense, injury or other liability that arises out of or in connection with this report including, without limitation, any indirect, special, incidental, punitive or consequential loss, liability or damage of any kind.

Copyright Notice

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]

Principal Engineer, Transmission Planning

[redacted]

Section: **5.2, 5.3**

Discipline: Stations Planning

Contributed by:

[redacted]

Sr. Engineer, Stations Planning

[redacted]

Section: **5.4**

Discipline: Transmission Lines Engineering

Contributed by:

[redacted]

Sr. Engineer, Transmission Lines Engineering

[redacted]

Executive Summary

[redacted] the interconnection customer (IC), requests to interconnect its [redacted] (2025 CEAP IR # 53) to the BC Hydro (BCH) system. [redacted] has thirteen (13) [redacted] solar inverters, rated 2.84 MW, providing 36 MW of supply into the BC Hydro system. The Point of Interconnection (POI) is a tap on the 138 kV line 1L249 MIG-MR2 – on the MIG-Str0/0i section of the line owned by [redacted] – approximately 5.68 km from Merritt 2 Substation (MR2). The IC's proposed commercial operation date (COD) is December 15, 2027.

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 follow:

1. The IC proposed POI is a tap on the customer owned section of the 138kV line 1L249. The interconnection configuration at the POI will be determined by [redacted], who also owns the MIG Generating Station. Further, any upgrades required for the MIG-owned facilities will be MIG's responsibility.

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 782 Ampere;

   b. Re-conductoring 1L205 HLD-SVA (approximately 41.8 km) to a minimum summer rating of 568 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. [redacted] is not allowed to operate in an island with BC Hydro load. An anti-islanding transfer trip scheme is required to isolate the solar farm to avoid potential islanding operations with BC Hydro loads.

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 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

Executive Summary **vi**

1 Introduction **1**

2 Purpose and Scopes of Study **3**

3 Standard and Criteria **4**

4 Assumptions and Conditions **5**

5 System Studies and Results **6**

5.1 Power Flow Study Results 6

5.1.1 Thermal Overload Analysis 6

5.1.2 Steady-State Voltage Analysis 7

5.1.3 Reactive Power Capability Evaluation 7

5.1.4 Anti-Islanding Requirements 8

5.2 Fault Analysis 8

5.3 Stations Requirements 8

5.4 Transmission Line Requirements 8

6 Cost Estimate and Schedule **10**

7 Conclusions **11**

Appendices

Appendix A Plant Single Line Diagram Used for Power Flow Study

Appendix B Power Flow Study Results

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]
MIG	[redacted] (Merritt Green Energy Project) Generating Station
[redacted]	[redacted]
MPO	Maximum Power Output
MR2	Merritt 2 Substation
NERC	North American Electric Reliability Corporation
NRIS	Network Resource Interconnection Service
OATT	Open Access Transmission Tariff
[redacted]	[redacted]
POI	Point of Interconnection
RAS	Remedial Action Scheme
[redacted]	[redacted]
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)	Tap on 1L249, 5.68 km from MR2	
IC's Proposed COD	15th December 2027	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	36 (Summer)	36 (Winter)
Number of Inverters	13 x 2.84 MW Inverters	
Plant Fuel	Solar	

[redacted] the interconnection customer (IC), requests to interconnect its [redacted] (2025 CEAP IR # 53) to the BC Hydro system. [redacted] has thirteen (13) [redacted] solar inverters rated 2.84 MW, providing 36 MW of supply into the BC Hydro system. The Point of Interconnection (POI) is a tap on 138 kV line 1L249 – on the MIG-Str0/0i section of line owned by [redacted]. – approximately 5.68 km from Merritt 2 Substation (MR2). The total rated output of the IPP is 36.9 MW, +/-17.9 MVAR. 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 proposed [redacted] (P53). The Point of Interconnection (POI) of the [redacted] project is a tap on 138 kV transmission line 1L249, 5.68 km from Merritt 2 Substation (MR2). The tap on line 1L249 will be 0.01 km away from MIG, near Str0/0i which is approximately 5.68 km away from MR2. MR2 connects through line 1L254 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]

[redacted]).

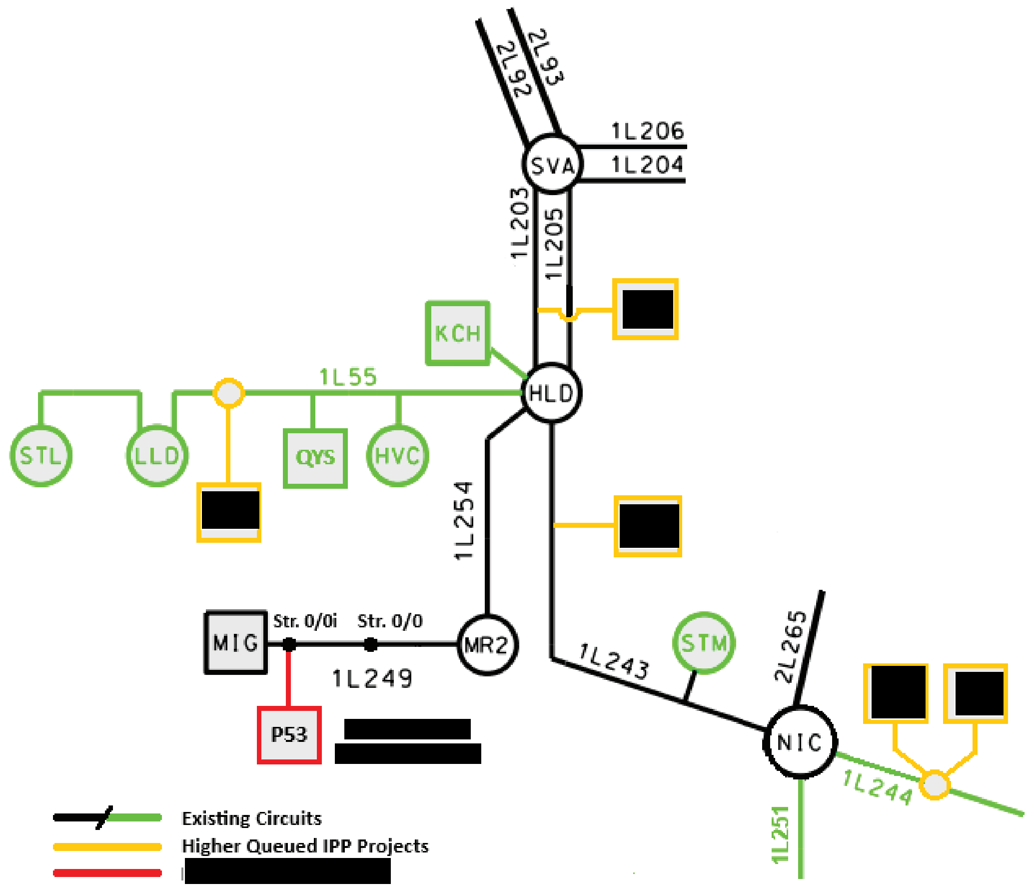

Figure 1-1: Proposed [redacted] (P53) and the BC Hydro Local Area Transmission System

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 tap connection at the proposed POI on 1L249 is assumed acceptable to interconnect the IC's generating project to the BCH system. The POI location is on a privately owned section of 1L249 and the interconnection configuration at the POI will be determined by [redacted], who also owns the MIG Generating Station. Further, any upgrades required for the MIG-owned facilities will be MIG's responsibility.

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 103% on 1L203 SHQ-SVA and 108% 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 782 Ampere;
- Re-conductoring 1L205 HLD-SVA (approximately 41.8 km) to a minimum summer rating of 568 Ampere.

There are no overloads on line 1L254 HLD-MR2 and 1L249 MR2-Str0/0 (the BC Hydro owned section of the line), under any load conditions or contingencies.

Under single contingencies (i.e. 1L203, 1L205, 1L243), the study finds branch overloads on 1L203, 1L205, and 1L243 ([redacted]-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. An anti-islanding transfer trip scheme is required to isolate the solar farm to avoid potential islanding operations with BC Hydro loads.

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 minimum 782 A summer rating
- At Highland (HLD) substation, upgrade 1L205 line jumper to minimum 568 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.
- Fibre optic cable on transmission structures of 1L249 from MR2 to [redacted] project (approximately 5.7 km) & [redacted] to MIG

(approximately 0.5 km). Structure replacement/addition may be required on 1L249.

6 Cost Estimate and Schedule

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

7 Conclusions

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

1. The IC proposed POI is a tap on the customer owned section of the 138kV line 1L249. The interconnection configuration at the POI will be determined by [redacted] who also owns the MIG Generating Station. Further, any upgrades required for the MIG-owned facilities will be MIG's responsibility.
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 782 Ampere;
   b. Re-conductoring 1L205 HLD-SVA (approximately 41.8 km) to a minimum summer rating of 568 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. [redacted] is not allowed to operate in an island with BC Hydro load. An anti-islanding transfer trip scheme is required to isolate the solar farm to avoid potential islanding operations with BC Hydro loads.
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 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.

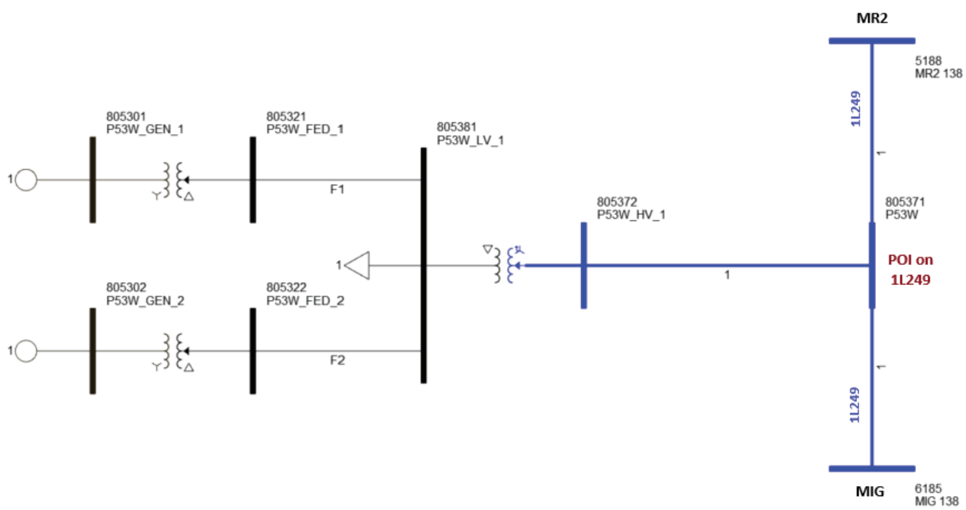

Figure A-1: [redacted] Single Line Diagram for Power Flow Study.

As shown in Figure A-1, [redacted] system includes 2 – 25 kV collector feeders; 1 – 50 MVA, 25/134.5 kV main transformer; and a 0.5 km, 138 kV transmission line from the [redacted] project's 138 kV substation to the interconnection point on 1L249 MIG-MR2. The feeders respectively connect to 7 and 6 – 0.6 kV, 3.15 MVA/2.84 MW generators, each provided with a 3.15 MVA, 0.6/24.9 kV step-up transformers. The maximum generating capacity is 36.9 MW and the maximum VAR output is +/- 17.8 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	36.9	P0	System Normal	60.7 31.7 %	165.8 86.7 %	116.7 78 %	18.6 6.2 %	128.1 42.6 %	126.8 42.1 %
		P1	1L203 OOS	X	X	173 115.6 %	12.9 4.3 %	134.6 44.7 %	133.2 44.3 %
		P1	1L205 OOS	129.7 67.8 %	236.5 123.7 %	X	40.8 13.6 %	170.3 56.6 %	169.1 56.2 %
		P1	1L243 OOS	55.6 29.1 %	160.9 84.1 %	112.1 74.9 %	X	X	X
		P2	1L203 open at HLD	X	105.4 55.1 %	153.6 102.6 %	19.5 6.5 %	151.8 50.5 %	150.5 50 %
		P2	1L203 open at SVA	105.6 55.2 %	X	217.3 145.2 %	56.5 18.8 %	191.1 63.5 %	189.9 63.1 %
		P2	1L243 open at HLD	55.4 29 %	160.6 84 %	111.9 74.8 %	X	140 46.5 %	138.5 46 %
		P2	1L243 open at NIC	125.5 65.6 %	230.4 120.5 %	177.7 118.8 %	135.8 45.1 %	1.7 0.6 %	X
32HS	36.9	P0	System Normal	66.6 38.5 %	171.8 99.4 %	122.4 103.2 %	17.2 6.8 %	130.6 51.7 %	129.4 51.2 %
		P1	1L203 OOS	X	X	182.6 154 %	11.8 4.7 %	139.1 55.1 %	138 54.6 %
		P1	1L205 OOS	138.9 80.4 %	246 142.4 %	X	44.5 17.6 %	174.6 69.1 %	173.7 68.7 %
		P1	1L243 OOS	62.7 36.3 %	168.2 97.4 %	119 100.3 %	X	X	X
		P2	1L203 open at HLD	X	105.5 61.1 %	162.9 137.4 %	22.8 9 %	156.5 61.9 %	155.4 61.5 %
		P2	1L203 open at SVA	105.6 61.1 %	X	226.6 191.1 %	60.7 24 %	195.6 77.4 %	194.6 77 %
		P2	1L243 open at HLD	62.5 36.2 %	167.9 97.1 %	118.6 100.1 %	X	140.1 55.5 %	138.8 55 %
		P2	1L243 open at NIC	132.4 76.6 %	237.4 137.3 %	184.2 155.4 %	135.9 53.8 %	1.6 0.6 %	X
35LS	36.9	P0	System Normal	73.3 42.4 %	177.4 102.7 %	128.2 108.1 %	115.9 43.9 %	253.8 96.1 %	255 96.5 %
		P1	1L203 OOS	X	X	193.2 162.9 %	126.9 48.1 %	264.6 100.2 %	266 100.7 %
		P1	1L205 OOS	148 85.7 %	255.7 147.9 %	X	161.6 61.2 %	296.9 112.4 %	299 113.2 %
		P1	1L243 OOS	131.8 76.2 %	235.5 136.3 %	183.1 154.4 %	X	X	X
		P2	1L203 open at HLD	X	104.2 60.3 %	173 145.9 %	144.4 54.7 %	281 106.4 %	282.7 107 %
		P2	1L203 open at SVA	102.5 59.3 %	X	234.8 198 %	183.2 69.4 %	317.8 120.3 %	320.1 121.2 %
		P2	1L243 open at HLD	131.7 76.2 %	235.4 136.2 %	183 154.4 %	X	142 53.8 %	141.8 53.7 %
		P2	1L243 open at NIC	199.8 115.6 %	302.8 175.2 %	246.8 208.2 %	134.3 50.8 %	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	MR2 138
31HW	36.9 MW	P0	System Normal	1.01 PU	1.03 PU	1.01 PU	1.01 PU
		P1	1L203 OOS	1.02 PU	1.03 PU	1.02 PU	1.01 PU
		P1	1L205 OOS	1.01 PU	1.03 PU	1.02 PU	1.01 PU
		P1	1L243 OOS	1.01 PU	1.03 PU	1.01 PU	1.01 PU
		P2	1L203 open at HLD	1.01 PU	1.03 PU	1.01 PU	1.01 PU
		P2	1L203 open at SVA	1.01 PU	1.02 PU	1.01 PU	1.01 PU
		P2	1L243 open at HLD	1.01 PU	1.03 PU	1.01 PU	1.01 PU
		P2	1L243 open at NIC	1.01 PU	1.03 PU	1.01 PU	1.01 PU
32HS	36.9 MW	P0	System Normal	1.01 PU	1.03 PU	1.01 PU	1.01 PU
		P1	1L203 OOS	1.02 PU	1.03 PU	1.02 PU	1.01 PU
		P1	1L205 OOS	1.01 PU	1.03 PU	1.02 PU	1.01 PU
		P1	1L243 OOS	1.01 PU	1.02 PU	1.01 PU	1.01 PU
		P2	1L203 open at HLD	1.01 PU	1.03 PU	1.01 PU	1.01 PU
		P2	1L203 open at SVA	1.01 PU	1.02 PU	1.01 PU	1.01 PU
		P2	1L243 open at HLD	1.01 PU	1.03 PU	1.01 PU	1.01 PU
		P2	1L243 open at NIC	1.01 PU	1.02 PU	1.01 PU	1.01 PU
35LS	36.9 MW	P0	System Normal	1.01 PU	1.02 PU	1.02 PU	1.01 PU
		P1	1L203 OOS	1.01 PU	1.02 PU	1.02 PU	1.01 PU
		P1	1L205 OOS	1 PU	1.02 PU	1.02 PU	1 PU
		P1	1L243 OOS	1.01 PU	1.03 PU	1.01 PU	1.01 PU
		P2	1L203 open at HLD	1 PU	1.02 PU	1.02 PU	1.01 PU
		P2	1L203 open at SVA	1 PU	1.01 PU	1.01 PU	1.01 PU
		P2	1L243 open at HLD	1.01 PU	1.02 PU	1.01 PU	1.01 PU
		P2	1L243 open at NIC	1 PU	1.03 PU	1.01 PU	1.01 PU