BC Hydro
Power smart

[redacted] Project

Interconnection System Impact Study

BC Hydro Permit to Practice #: 1002449

[redacted]

Prepared for: [redacted]

Prepared by: [redacted] [redacted]

[redacted]
Engineer, Interconnection Planning

Reviewed by: [redacted]

[redacted].
Manager, Interconnection Planning

Accepted by: [redacted]

[redacted]
Manager, Transmission Assets Planning

2024 Apr 05

100-APR-00002

Contributors

The following Professionals of Record (POR) accept responsibility for their technical content in the specified respective sections. Professionals apply their signature and/or seal for the technical or non-technical content as appropriate.

Section: Entire report except sections listed below

Discipline: Transmission Planning

Contributed by: [redacted]

[redacted]
Engineer, Interconnection Planning

[redacted]

Section: **5.4**

Discipline: Analytical Studies

Contributed by: [redacted]

[redacted]
Specialist Engineer, Substations Growth and Sustainment

[redacted]

Section: **5.5 5.7**

Discipline: Station Planning

Contributed by: [redacted]

[redacted]
Sr. Engineer, Substations Growth and Sustainment

[redacted]

Section:	**Discipline:**
5.6	Transmission Operations Services

Contributed by: [redacted]

[redacted]
Sr. Engineer, Transmission Operations Services

[redacted]

Section:	**Discipline:**
5.8	Transmission Line Engineering

Contributed by: [redacted]

[redacted]
Sr. Engineer, Transmission Lines Engineering

[redacted]

Section:	**Discipline:**
5.5, 5.9.1, 5.9.2	P&C Planning

Contributed by: [redacted]

[redacted]
Consultant, P&C Planning

[redacted]

Section:	**Discipline:**
5.9.3	Telecom Planning

Contributed by: [redacted]

[redacted]
Specialist Engineer, Telecom Planning

[redacted]

Section: **Discipline:**

5.10 Revenue Metering System Mgmt

Contributed by: [redacted]

[redacted]

[redacted]

Sr. Engineer, Revenue Metering System Mgmt

The following accept responsibility for the content in Section 6 Cost Estimate and Schedule, but the cost/schedule information is not covered by any of the P.Eng seals/stamps.

Section: **Discipline:**

6 Cost Estimate and Schedule

Contributed by: [redacted] 5 APR 2024

[redacted]

Interconnection Manager, Interconnections

Report Metadata

Header:	[redacted] Project
Subheader:	Interconnection System Impact Study
Title:	BC Hydro Permit to Practice #: 1002449
Subtitle:	[redacted]
Report Number:	100-APR-00002
Revision:	0
Confidentiality:	Public
Date:	2024 Apr 05
Volume:	1 of 1

Prepared for:	[redacted]
Prepared by:	[redacted]
Title:	Engineer, Interconnection Planning
Checked by:	[redacted]
Title:	Sr. Engineer, Interconnection Planning
Reviewed by:	[redacted]
Title:	Manager, Interconnection Planning

Related Facilities:	
Additional Metadata:	Transmission Planning 2024-007

Revisions

Revision	Date	Description
0	2024 Apr	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

Table of Contents

Tables

Figures

Acronyms

The following are acronyms used in this report.

BEH	Bethlehem Substation
BESS	Battery Energy Storage System
COD	Commercial Operation Date
CRN	Carson Microwave Station
DTT	Direct Transfer Trip
ERIS	Energy Resource Interconnection Service
FVO	Fraser Valley Office
HLD	Highland Substation
HLSx	[redacted] Station
HLTx	[redacted] Terminal Station
HLTB2B	Proposed back-to-back antenna to provide a passive repeater near HLTx
HVC	Highland Valley Copper Substation
IC	Interconnection Customer
KCH	Kwoiek Creek Generating Station
LLD	Lower Level Dam Substation
MIG	Merritt Green Energy Project Generating Station
MR2	Merritt 2 Substation
NERC	North American Electric Reliability Corporation
NIC	Nicola Substation
NRIS	Network Resource Interconnection Service
OATT	Open Access Transmission Tariff
OO	Operating Order
POI	Point of Interconnection
PV	Photovoltaic
QYS	quA-ymn Solar Project
RAS	Remedial Action Scheme
SIS	System Impact Study
SIC	South Interior Control
SIO	South Interior Office
STL	Spatsum Substation
SVA	Savona Substation
TBD	To Be Determined
TIR	BC Hydro 60 kV to 500 kV Technical Interconnection Requirements for Power Generators
WECC	Western Electricity Coordinating Council

Executive Summary

[redacted] Limited Partnership, the Interconnection Customer (IC), proposed to build a solar farm with BESS (Battery Energy Storage System), which is approximately 37 km from Highland (HLD) substation, near the Highland Valley Copper mine in the South Interior region of British Columbia.

The [redacted] project includes 172.8 MVA solar inverter facilities collecting the output from the PV panels and 170 MVA battery inverter groups. While the total installed inverter capacity is 342.8 MVA, the IC proposed maximum power injection to the BCH system will be capped at 150 MW. The IC had indicated the Highland BESS will only be charged from the Highland PV system, and the BESS will not be charged from the BCH system.

The details of the project information can be found in the Introduction section. The IC proposed Point of Interconnection (POI) is on the existing radial138 kV transmission line 1L55, about 37 km from HLD. The IC proposed commercial operation date (COD) is July 31, 2026; however, the required network upgrades stated below would be unable to complete before the proposed COD.

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

- A three-circuit-breaker-ring switching station is required for interconnecting the [redacted] Project. This proposed switching station is close to the IC proposed POI on 1L55 and is tentatively named as [redacted] Terminal Station (HLTx) in this SIS.

- When [redacted] project is connected, the section of 1L55 from HVC tap to the proposed switching station HLTx needs to be uprated to 800 Amps under 30°C ambient temperature.

- The [redacted] inverters are required to have voltage ride-through (VRT) and frequency ride-through (FRT) capabilities per BCH's TIR. With the default settings provided, the fault ride-through performance of the proposed inverters is satisfactory.

- The Highland project inverters are required to have primary frequency response capability per the TIR. With the settings provided, the frequency response performance of the proposed inverters is satisfactory.

- The [redacted] project is not arranged for islanded operation. The IC is required to install anti-islanding protection within their facility to disconnect the [redacted] site from the grid when an inadvertent island with the local loads forms.

- Voltage sags caused by energization of entrance transformers are expected to exceed the limits specified by the TIR. Point-On-Wave (POW) controlled closing of the transformer 138 kV circuit breaker is required to control the magnetizing inrush current and the associated voltage sag.

- A direct transfer tripping (DTT) scheme is required to disconnect the tie line at HLTx and disconnect the [redacted] from the BCH system if there is a protective operation or no-fault opening of transmission line 1L55 between the BCH HLD substation and the new switching station (HLTx).

- The 138 kV circuit breakers should have the out-of-phase current interrupting capability to trip the tie line to the solar farm at the new switching station (HLTx).

- The IC needs to meet the harmonic limitations that are specified in IEEE 519-2022 standard. Harmonic studies will be required when the associated data becomes available.

- New RAS functions are proposed to block the [redacted] generation injection to BCH system to mitigate interior to lower mainland thermal overload issues under contingencies.

- BCH will provide line protections for 1L55_A, 1L55_B and 1L55_C protections, after the existing 1L55 being segregated as a part of this project interconnection. The IC is to provide entrance protection at IC's station HLSx to comply with BCH's TIR. The IC is to provide two SEL-411L relays at the entrance of HLSx to provide protection coverage for 1L55_C.

- BCH will provide a new control system for the new switching station HLTx, including remote and local control and indication for the new devices that will be installed at HLTx.

- The IC is required to install two 48-strand single mode fibre optic cable from HLTx to HLSx.

The cost estimate provided for the Interconnection Network Upgrades is a non-binding good-faith cost estimate based on a Class 5, conceptual level estimate. The cost estimate for the Interconnection Network Upgrades required to interconnect the proposed project to BCH Transmission System is $62.18 million (+100%/-35%). The cost estimate includes 35% contingency.

The non-binding good faith estimated time to construct is 4 to 5 years after completion of the Interconnection Facilities Study stage and execution of a Standard Generator Interconnection Agreement (SGIA), which indicates that the IC's proposed COD of July 31, 2026 can not be achieved.

The Interconnection Facilities Study report will provide greater detail of the Interconnection Network Upgrade requirements along with a Class 3 preliminary estimate (+15%/-10%) and estimated construction timeline for this project.

1 Introduction

[redacted] Limited Partnership, the Interconnection Customer (IC), proposed to build a solar farm with Battery Energy Storage System (BESS) at approximately 37 km from HLD substation, near the Highland Valley Copper mine in the South Interior region of British Columbia.

The [redacted] Project's installed capacity and the commercial operation date (COD) are as follows:

- The project will consist of 48 SG3600 type solar photovoltaic (PV) inverters rated at 3.6 MVA each, and 34 SC5000 type battery energy storage system (BESS) inverters rated at 5 MVA each.
- While the total installed capacity is 342.8 MVA, the IC proposed maximum power injection to the BCH system will be capped at 150 MW. The IC had indicated the Highland BESS will be charged from the Highland PV system only, and the BESS will not be charged from BCH system.
- The IC indicated that the [redacted] project does not have black start capability.
- The IC proposed commercial operation date (COD) is July 31, 2026.

The project reviewed in this SIS is summarized in Table 1-1 below.

Table 1-1 Summary of Project Information

Project Name	[redacted]	
Interconnection Customer	[redacted] Limited Partnership	
Point of Interconnection	A point on 1L55, 37 km from HLD	
IC Proposed COD	July 31, 2026	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	150 (Summer)	150 (Winter)
Number of Generator Units	48 PV Inverters, each collecting power from PV Panels, total capacity 172.8 MVA 34 BESS Inverters, each connected to battery groups, total capacity 170 MVA	
Plant Fuel	Solar Energy & Battery	

The power generation from the solar inverters will firstly be stepped up to 34.5 kV voltage level through step-up pad-mount transformers, and then stepped up to the 138 kV voltage level via two 85/113 MVA, 138 kV (Y-gnd) / 34.5 kV (Δ) transformers. The power generation will be transmitted through an IC owned 0.05 km, 138 kV transmission line to the exiting BCH line 1L55 between Highland station (HLD) and Lower Level Dam station (LLD).

A three-circuit-breaker-ring switching station is required for interconnecting the [redacted] Project. This proposed switching station is close to the IC proposed Point of Interconnection (POI) on 1L55, which is approximately 37 km from HLD. The tentative name for the switching station is [redacted] Terminal Station (HLTx) in this SIS.

After addition of the 3-Circuit Breaker ring switching station (HLTx), the existing 138 kV line 1L55 from HLD to STL will be separated into two sections, one between HLD and HLTx which is tentatively designated as 1L55_A and one between HLTx and Spatsum station (STL), which is tentatively designated as 1L55_B. The IC's line from HLTx to the IC owned station HLSx is tentatively designated as 1L55_C.

There are three industrial facilities fed by the existing circuit 1L55: Highland Valley Copper station (HVC), Lower Level Dam station (LLD) and Spatsum station (STL). The three load stations are owned by the same customer: Highland Valley Copper. This load customer had proposed a HVC Load Increase Project with a new customer owned substation to be connected to 1L55 as well.

There are two existing generation stations owned by other independent power producers (IPP) in the nearby area. One is Kwoiek Creek Generating Station (KCH) with a total capacity of 60 MW connected to HLD via a 72.7 km, 138 kV transmission line 1L57, and the other is Merritt Green Energy Project Generating Station (MIG) with a total capacity of 40 MW connected to Merritt 2 Substation (MR2) which is fed by 1L254 from HLD. The quA-ymn Solar generating project is under construction in the vicinity of [redacted] Project. The quA-ymn is included in this SIS.

HLD is a 138/60 kV substation in the Merritt area. In addition to supplying the industrial customer of Highland Valley Copper and interconnecting the existing local generators, HLD connects to BC Hydro's Savona (SVA) substation via 1L203 and 1L205, and Nicola (NIC) substation via 1L243. Combined with the local load and generation operating conditions, the dispatch pattern of generation from the Northern Region and from the South Interior will have some effect on the flows on 1L203, 1L205 and 1L243.

Figure 1-1 and Figure 1-2 below show the interconnection diagram and the geography location of [redacted] Project, respectively.

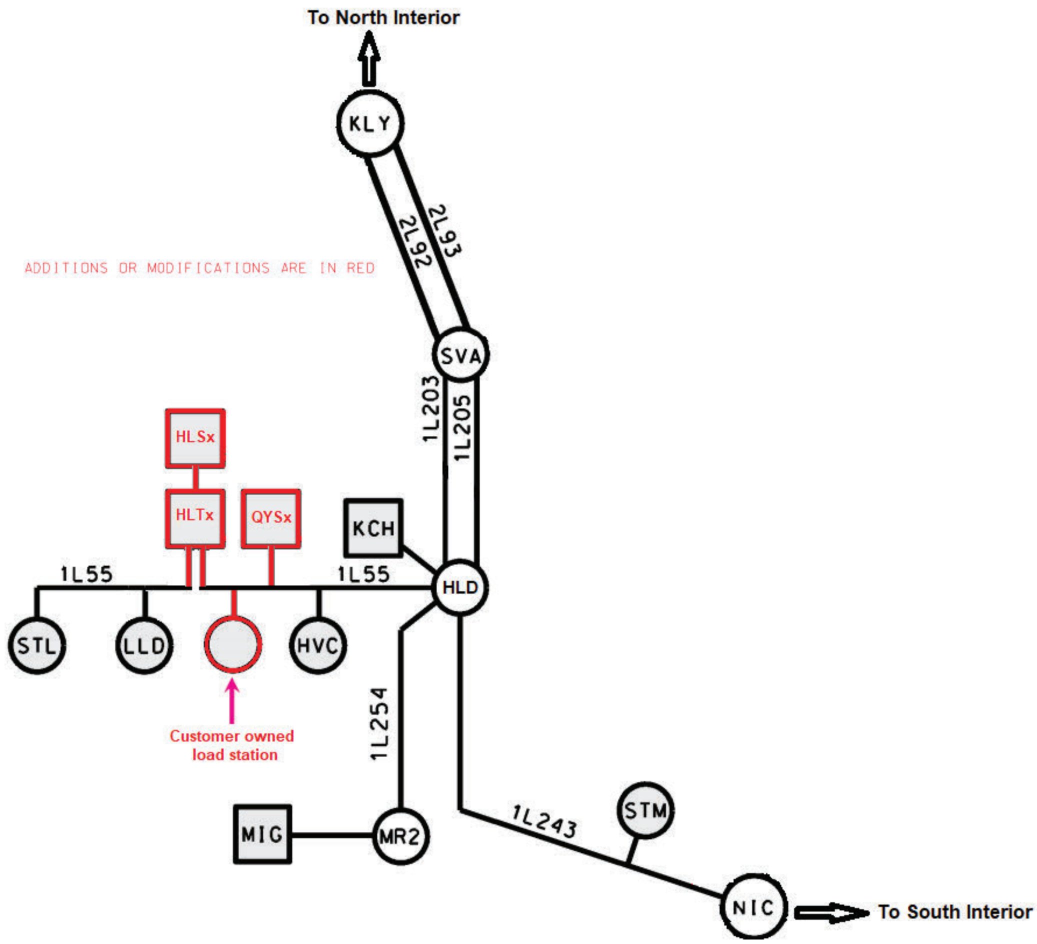

Figure 1-1: Interconnection Diagram of HLSx in its Vicinity Area

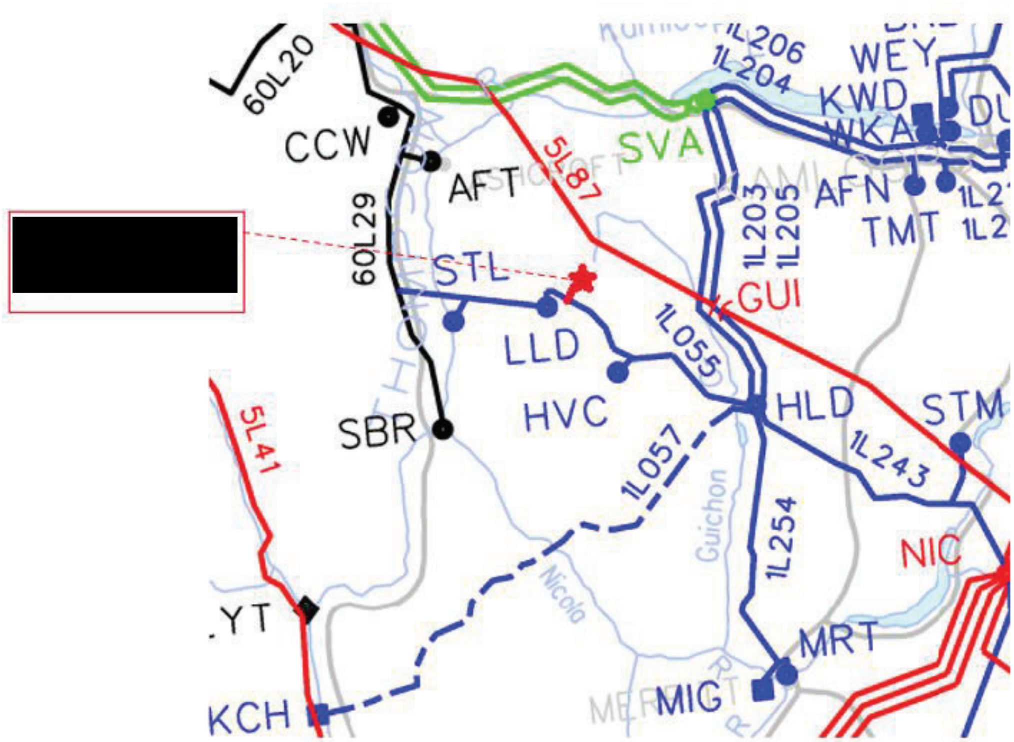

Figure 1-2: Regional Location of [redacted] Project

2 Purpose of Study

The purpose of this SIS is to assess the impact of the interconnection of the proposed project on the BCH transmission system per BCH's Open Access Transmission Tariff (OATT). This study is to identify any constraints and to suggest network upgrade options to obtain adequate performance for reliable operation of the transmission system.

The SIS is performed in compliance with the North American Electric Reliability Corporation (NERC) reliability standards, and Western Electricity Coordinating Council (WECC) transmission planning criteria, and the BCH transmission planning criteria, specifically:

- NERC standards: FAC-002-3 and TPL-001-4;
- WECC criteria: TPL-001-WECC-CRT-3.2;
- BC Hydro's 60 kV to 500 kV Technical Interconnection Requirements for Power Generators per FAC-001-3;
- BCH's TAP FAC-002-3 Study Guide.

3 Scope of Study

This SIS investigates and addresses the voltage profiles and overloading issues of the transmission system in the vicinity of the [redacted] project for the planning horizon because of the proposed interconnection. Studies completed include steady-state studies, dynamics studies and short circuit analysis to evaluate system performance, as well as protection coordination, operation flexibility, telecom requirements and high-level remedial action scheme (RAS) requirements. BC Hydro planning methodology and criteria are used in the studies as stated in Purpose of Study.

In pursuant to FAC-002-3, BC Hydro has taken the necessary measures to assess the potential reliability impact on the adjacent system.

4 Assumptions and Conditions

This SIS is performed based on the information in the IC's interconnection data form submitted in March 2023. Assumptions are made wherever the IC's input data is unavailable.

The key assumptions and study conditions used in this SIS are listed below.

- BC Hydro 2026 light summer load and heavy winter load base cases are selected in performing this SIS. With the continuous local load growth, the 2026 base cases with [redacted] represent more constrained local system conditions than those in other future years. In these 2026 base cases, the intertie exchanges are set within their long-term firm transfers.
- Higher-queued customer generation and load interconnection projects in the nearby area are included in this SIS.
- In the 2026 summer light load system condition, to establish the stressed operating scenarios, the Kwoiek Creek generators (KCH), Merritt Green Energy generator (MIG), and the higher-queued quA-ymn Solar generation project is set with their maximum power injection to BCH.
- The achievable fault clearing times for selected contingencies are summarized in
- Table 4-1 below.

Table 4-1: Assumed Fault Clearing Time

Outage	3Φ Fault Location	Assumed Fault Clearing Time (Cycles)	
		Close End	Far End
1L203/1L205 (HLD – SVA)	Close to HLD	HLD 7	SVA 9
1L203/1L205 (HLD – SVA)	Close to SVA	SVA 7	HLD 9
1L243 (HLD – NIC)	Close to HLD	HLD 7	NIC 9
HLD T2 LV bus	25 kV bus	T2 25kV 60	--
HVC TN	138 kV side	TN HV 8	--
1L55 (STL – HLTx)	Close to HLTx	HLTx* 24	--
1L55 (STL – HLTx)	Close to LLD	LLD 10	--

* Assumed conversative fault clearing times for the proposed switching station at POI.

5 System Studies and Results

5.1 Steady State Study

To evaluate whether the [redacted] Project addition would cause any adverse impact in the nearby area, a series of pre-contingency and post-contingency power flow analyses were performed using 2026 heavy winter and 2026 light summer base cases with the assumptions stated above. Steady-state studies were performed in accordance with the NERC TPL-001-4 Planning Standard.

When the [redacted] project is connected, the surrounding area bus voltages under system normal (N-0) and single contingencies (N-1) are observed to be within acceptable limits. When [redacted] project is not connected (pre-project condition), the bus voltages under system normal in the surrounding areas are observed to be within acceptable limits, too. The effect of Kwoiek Creek generators (KCH) outage during winter was considered in 2026 heavy winter base case, and this outage would result in comparable surrounding area bus voltages under system normal and N-1 contingencies.

Thermal overloading of the 1L55 line section from the HVC tap to the proposed switching station was observed in the transmission system in system normal (N-0) conditions. This section of 1L55 line is approximately 19.14 kms, and the section rating is 254A Summer (30°C) and 488 A Winter (0°C) at maximum conductor temperature of 49°C. Upgrades of the transmission line 1L55 are needed from the HVC tap to the POI to achieve the rating of 800 A under (30°C), which is same as the thermal rating of 1L55 from HLD to HVC tap.

Selected transmission study results in various system scenarios are listed in Table 5-1.

The BCH TIR requires wind/solar generators have the dynamic reactive power capability at a minimum of +/- 33% of its Maximum Power Output (MPO) at the high voltage side of the IC's station. The [redacted] project show being capable of injecting and absorbing reactive power greater than +/-49.5 Mvar, and the simulations for the [redacted] project indicate that the project meet the reactive capability requirements.

Table 5-1: Selected Steady State Study Results

		1L55 Branch Sections						Surrounding Area Busses						
		1L55 HLD-HVC tap	1L55 HVC-BEH	1L55 BEH-QYS	1L55 QYS-HLTx[2]	1L55 HLTx-LLD	1L55 LLD-STL tap-STL	HLSx POI (HLTx) 138	QYS POI 138	HVC tap 138	LLD 138	HLD 138	SVA 138	NIC 138
		Branch Summer Rating and Loadings Under Contingency						Bus Voltages (PU) in Summer						
Branch Summer Rating (MVA)		191.2[1]	60.7	60.7	60.7	60.7	60.7							
P0	System Normal	6	202	220	199	47	6	1.047	1.02	1.008	1.045	1.011	1.012	1.013
P0[3]	System Normal (no HLSx)	89	49	32	54	55	7	0.928	0.937	0.941	0.926	0.960	1.004	1.009
		Branch Winter Rating and Loadings Under Contingency						Bus Voltages (PU) in Winter						
Branch Winter Rating (MVA)		191.2[1]	116.6	116.6	116.6	116.6	116.6							
P0	System Normal	8	104	113	102	25	3	1.048	1.022	1.011	1.046	1.018	1.02	1.025
P0[3]	System Normal (no HLSx)	88	25	16	28	28	4	0.937	0.946	0.950	0.935	0.988	1.013	1.028

Notes:
(1) Limited by CT settings of 800 A.
(2) The tentative name for the switching station is [redacted] Terminal Station (HLTx).
(3) System normal without [redacted] (i.e., pre-project system) has been studied for N-0 condition.

5.2 Transient Stability Study

Transient stability studies have been performed using the 2026 heavy winter and 2026 light summer base cases to assess the impact of [redacted] Project on the transmission network in the vicinity area, in accordance with the TPL-001-WECC-CRT-3.2 Performance Criteria. The Kwoiek Creek generators (KCH), Merritt Green Energy generator (MIG), and the two higher-queued generation projects are set with the maximum power injection to BCH system to represent maximum system stress.

Various PV and BESS dispatch combination scenarios are considered and studied, such as the PV dispatched at IC's maximum power output of 150 MW while BESS is set at 0, and the BESS set at IC's maximum power output of 150 MW while PV is dispatched at 0. The outcomes of various PV and BESS dispatch combination scenarios are comparable.

No transient instability has been observed based on the studied scenarios and contingencies. A summary of the selected transient stability studies for 2026 light summer load conditions with [redacted] dispatched at its maximum output of 150 MW is provided in Table 5-2 below.

The [redacted] inverters are required to have voltage ride-through (VRT) and frequency ride-through (FRT) capabilities per BCH's TIR. With the default settings provided by the vendor, the fault ride-through performance of the [redacted] inverters is satisfactory and does not result in inverters tripping in dynamic simulations.

Table 5-2: Selected Transient Stability Study Results (2026 Light Summer)

NERC TPL-001-4 Category	Case	Contingency	3-Ph Fault Location	Fault Clearing Time (Cycles)		[redacted] project Performance	Minimum Transient Voltage @ POI (PU)	Other Non-Islanded Units
				Close End	Far End			
P1	P1-1	1L203/1L205 (HLD – SVA)	Close to HLD	HLD 7	SVA 9	Acceptable	0.98	Acceptable
	P1-2	1L203/1L205 (HLD – SVA)	Close to SVA	SVA 7	HLD 9	Acceptable	1.03	Acceptable
	P1-3	1L243 (HLD – NIC)	Close to HLD	HLD 7	NIC 9	Acceptable	1.03	Acceptable
	P1-4	HLD T2 LV bus	25 kV bus	T2 25kV 60	--	Acceptable	1.05	Acceptable
	P1-5	HVC TN HV bus	138 kV side	TN HV 8	--	Acceptable	1.05	Acceptable
	P1-6	HVC TN LV bus	13.8 kV side	TN LV 60	--	Acceptable	1.04	Acceptable
	P1-7	1L55 (STL – HLT)	Close to HLT	HLT* 24	--	Acceptable	1.05	Acceptable

* Assumed conversative fault clearing times for the proposed switching station at POI.

5.3 Reliability Impact to Adjacent Utilities

The reliability impact of the proposed interconnection to adjacent system was monitored in accordance with FAC-002-3. No unacceptable performance is observed in the adjacent system.

5.4 Analytical Studies

Analytical Studies assessed the impact of the 150 MW [redacted] Project based on the customer provided data. The study identified the following key findings and recommendations:

- Voltage sags caused by energization of entrance transformers are expected to exceed the limits specified by BC Hydro's Technical Interconnection Requirement (TIR). Point-On-Wave (POW) controlled closing of the transformer HV 138kV circuit breaker is required to control the magnetizing inrush current and the associated voltage sag.
- A direct transfer tripping (DTT) scheme is required to trip the 150 MW [redacted] and Storage Plant if there is a protective operation or no-fault opening of transmission line 1L55 between the BC Hydro HLD substation and the new switching station (HLTx).
- The 138kV circuit breakers should have the out-of-phase current interrupting capability to trip the solar farm at the new switching station (HLTx).
- The IC is required to meet the harmonic limitations that are specified in IEEE 519-2022 standard. Harmonic studies will be required when the associated data becomes available.
- The Power Parameter Information System (PPIS) meter is required within the Power Generating Facility to provide electrical parameters including but not limited to kW, kVar, kVA, Voltage, Current, Power Factor, Power Frequency and Harmonics.

For the [redacted] project as an Inverter-Based-Resource (IBR) plant, detailed EMT models of the interconnecting facilities should be submitted to BC Hydro at the Facilities Study stage. These models shall provide an accurate representation of the controls and protection features of the plant. The model will be used to demonstrate plant compliance with the requirements specified in BC Hydro's TIR.

5.5 Fault Analysis

The short circuit analysis for the SIS is based upon the latest BC Hydro system model, which includes project equipment and impedances provided by the IC. Thevenin impedances, including the near term and ultimate fault levels at POI, are not included in this report but will be made available to the IC upon request.

5.6 Remedial Action Scheme

System thermal overload issues had been identified in heavy summer scenario with extreme system conditions and under various contingencies, listed in Table 5-3 below.

Table 5-3: List of System Thermal Overload Issues for RAS Actions

Condition	Contingency	Overloaded circuits
Heavy Summer case with BC-US transfer high	5L81 and 5L82 or, 5L81 with 5L82 OOS, or 5L82 with 5L81 OOS,	5L44, 5L83, 5L87,
	5L81 and 5L83 or, 5L81 with 5L83 OOS, or 5L83 with 5L81 OOS,	5L44, 5L82, 5L87,
	5L82 and 5L83 or, 5L82 with 5L83 OOS, or 5L83 with 5L82 OOS,	5L81, 5L87
Heavy Summer case with Peace area high generation and South Interior low generation	5L87	1L204

The solution is proposed to block [redacted] power injection to BC Hydro system. The new RAS functions are proposed as follows in Table 5-4.

Table 5-4: RAS Functional Requirements

No.	Contingency (Note 1)	Block the [redacted] Power generation injection to BC Hydro system. (Note 2)	Speed Requirement (Note 3)
1	5L81 and 5L82 or, 5L81 with 5L82 OOS, or 5L82 with 5L81 OOS,	Yes	5 to 10 seconds
2	5L81 and 5L83 or, 5L81 with 5L83 OOS, or 5L83 with 5L81 OOS,	Yes	

3	5L82 and 5L83 or, 5L82 with 5L83 OOS, or 5L83 with 5L82 OOS,	Yes	
4	5L87	Yes	

Notes:

1. Contingency signal includes loss of line by fault or open terminal/tripping logic without fault.
2. The generation blocking signal should be sent to [redacted] Power station.
3. The speed requirement is defined as the time from the fault initiation to blocking the IC's generation injection.

5.7 Station Upgrade Requirements

A 138 kV three-breaker-ring switching station will be built to interconnect the proposed [redacted] farm, which includes the following requirements.

- A 2,000 A ring bus arrangement, and 138 kV circuit breakers (1CB1, 2, 3) are added with associated switching devices (1D1/2CB1, 2, 3).
- Termination of the 138 kV transmission line from [redacted] farm at HLTx, and terminations of 1L55 by looping in and out at HLTx.
- All other station facilities include but not limited to a station service transformer, current transformers, voltage transformers, surge arrestors, connector to a mobile diesel generator, ground grid, control building, lighting, fencing, lightening, etc. for HLTx functions.

The Draft of HLTx one line diagram is shown in Figure 5-1 below.

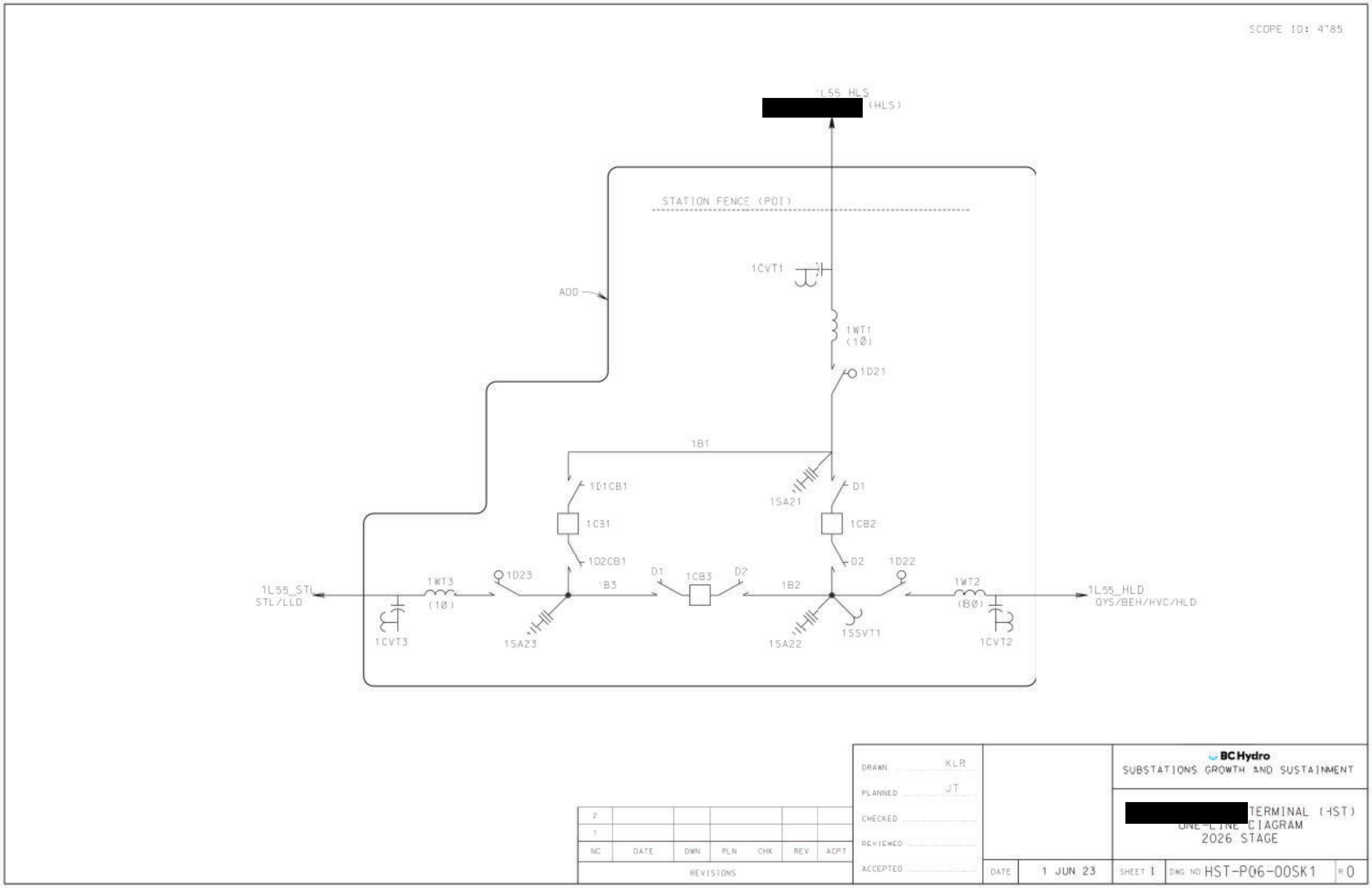

Figure 5-1: Draft of HLTx one line diagram

5.8 Transmission Line Requirements

Reconductor and re-termination of 1L55 are required to interconnect the 150 MW [redacted] project.

- Reconductor a portion of 1L55 line from HVC tap to the POI (which is approximately 19.14 km) to the new rating of 800A at 300 C summer ambient temperature.
- Re-terminate line 1L55 at approximately structure 23-10 (POI) to the new switching station HLTx and re-terminate the other portion of line 1L55 at approximately structure 23-10 (POI) to the new switching station HLTx.
- Two new dead-end structures should be installed in-line to re-terminate the existing line 1L55 at HLTx.
- The last span of the customer line from the customer substation into HLTx switching station, should have the owners engineer review (if design build by the customer) by BCH.
- Exact conductor will be determined at a later stage. At this time, it is assumed that Goose conductor would be able to provide the required rating as it also matches the existing section of line 1L55 from HLD to structure 11/9.

5.9 Protection, Control and Telecommunications

5.9.1 Protection Upgrade Requirement

BCH will provide line protections for 1L55_A, 1L55_B and 1L55_C protections. Existing 1L55 is a single transmission line but will be segregated into three as a part of this project: HLD to HLTx is 1L55_A, HLTx to STL is 1L55_B and HLTx to HLSx is 1L55_C. BCH to build a new 138kV three-breaker-ring terminal switching station (tentatively designated as HLTx) for interconnecting to the new proponent [redacted] Station (tentatively designated as HLSx).

The IC, Highland BC Solar Project Limited Partnership, is required to provide the following for the interconnection of [redacted] Station:

- Entrance protection that complies with the latest version of the “60 kV to 500 kV BC Hydro Technical Interconnection Requirements for Power Generators.”
- Provide two SEL-411L relays at the entrance of HLSx to provide protection coverage for 1L55_C. BC Hydro P&C Planning will provide settings for these relays.
- The IC with Inverter Based Resources shall provide the full model of their generation sources in a table format which includes current output, angle, and power factor at a variety of voltage levels. If the inverter is programmed to

output negative sequence current this information will be required as well. This will have to be provided to P&C Planning prior to P&C Planning begins work on the P&C Application.

- The IC is responsible for providing a communications link for remote interrogation of the line protection relays and PPIS equipment by BCH servers.
- Provide anti-islanding protection to prevent Highland project from operating in islanded condition.
- HLSx inverters are required to have fault ride-through (FRT) capabilities.
- HLSx shall install PDR 2000 telecom modules at their station to communicate with BCH RAS PDR 2000 telecom I/O modules at NIC.
- Derive appropriate actions to block HLSx generation injection to BC Hydro system instantaneously or within 5 to 10 seconds on receipt of RAS PY key and SY key from NIC. Proponent should ensure circuits associated with BC Hydro RAS shall be designed in compliance to PRC-012-2 R 4.1.5.

In addition, the following SIGNED and SEALED documents must be submitted by the IC to Protection Planning for review at least 8 weeks prior to the target Interconnection date.

- IFC Protection one-line diagram.
- Relevant DC schematics of protection relay(s) and wiring diagram
- Transformer nameplate drawings
- Generating Resource specifications that is usable by BC Hydro for protection studies
- Entrance HV interrupting device(s) nameplate with interruption time rating indicated.
- Relevant Protection relay(s) settings

5.9.2 Control Upgrade Requirement

BC Hydro will provide a new control system for the new HLTx, including remote and local control and indication for the new devices that will be installed at HLTx.

BC Hydro control center will add HLSx, HLTx and other changes to 1L55 as needed into the Energy Management System (EMS) network model.

The IC is required to report telemetry, and status information in real-time by exception using a RTU with DNP3 reporting to a Data Concentration Point per the Technical Interconnection Requirements (TIR) for Power Generators. The IC is responsible to provide a dedicated (always on) telecommunication to the closest BC Hydro station with appropriate telecom facilities (station to be determined by BC Hydro Telecom).

The IC is responsible for providing a PPIS meter, connected to a suitable high voltage source for harmonics and power quality metering. The selection of the PPIS meter is subject to BC Hydro approval.

The IC is also responsible for providing a communications link for remote interrogation of the line protection relays and PPIS equipment by BCH servers. As a minimum it can be a dial-up telephone line. Alternative communications include IP cellular modem, IP satellite, BCH WAN (where appropriate), and is subject to BCH review and approval.

Communications and equipment selection is subject to BCH review and approval.

In addition, IC may be asked to provide 1L55_C protection event records from 1L55_C protection relays to BC Hydro under the following circumstances (in circumstance that remote data access is not working).

- Fault on 1L55_C
- Relay mis-operation for fault outside 1L55_C
- Relay operation due to Power Quality Protection elements

The exchange of event reports will assist BC Hydro in analysing system disturbances. This should improve the protection performance of both BC Hydro and the IC for faults near points of interconnection.

Minor work will be required by BC Hydro to commission status, telemetries, alarms, and remote access at IC's facility.

5.9.3 Telecommunications Upgrade Requirement

A microwave solution from Carson Microwave Station (CRN) with clear passage over the 'HLSx' site would be necessary to deliver WECC Level 1 circuits to 'HLTx'. This would involve a right-of-way, covenant, or other instrument, as determined by BC Hydro Properties Department at a later stage.

Transport capacity for circuits is in limited supply on the BC Hydro network backbone in the vicinity of CRN. An existing power line carrier system would be employed to carry WECC Level 3 signals to HLD.

A few assumptions were made when delivering the above study results including right-of-way, access road, available existing telecom system capacity, commercial telecommunication service availability, and equipment availability, etc., but the details are not included in this report.

The [redacted] Project telecom block diagram is shown in Figure 5-2 below.

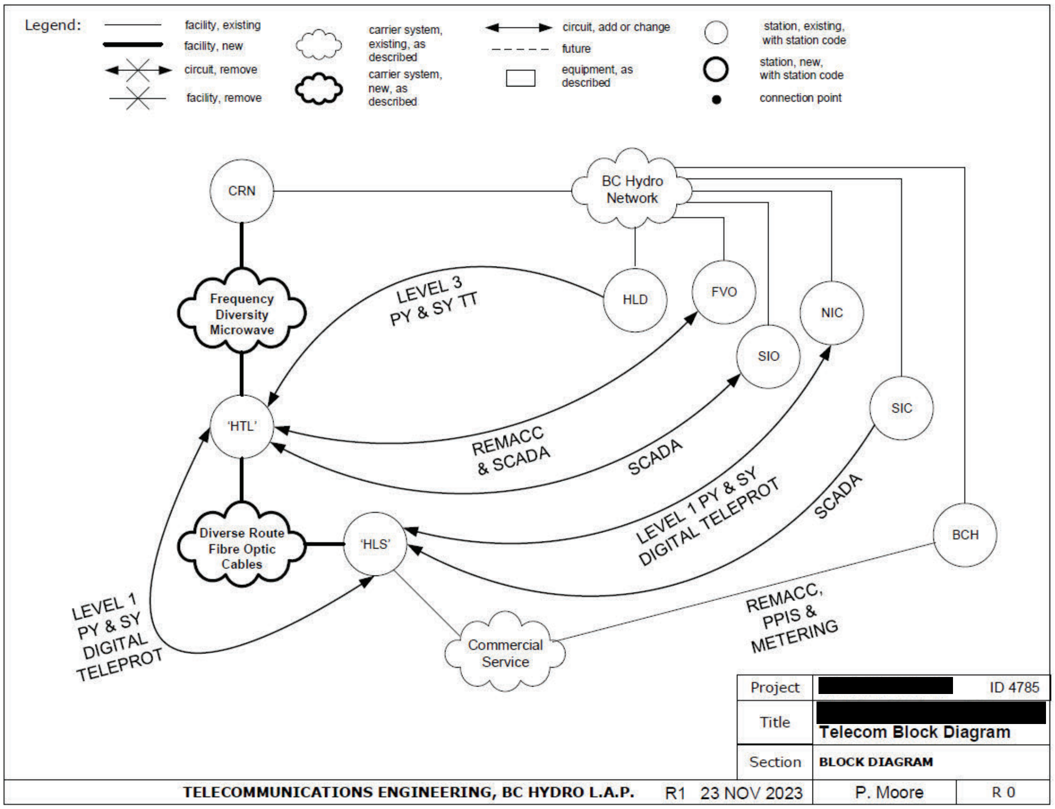

Figure 5-2 [redacted] Project Telecom Block Diagram

The requirements to derive the need for the telecom additions are described bellow.

Tele-protection Requirements for Telecom:

- Provide WECC Level 3 PY and SY transfer trip signals, HLD to 'HLTx, for "HLD 1L55_A PY DTT to 'HLTx' " and "HLD 1L55_A SY DTT to 'HLTx' ".
- Provide WECC Level 1 PY and SY 64 kbps synchronous circuits between 'HLTx' and 'HLSx' for " 'HLTx'-'HLSx' 1L55_C PY DIGITAL TELEPROT" and " 'HLTx'-'HLSx' 1L55_C SY DIGITAL TELEPROT". Physical interface shall be C37.94 optical over multimode fibre using ST connectors.
- Provide WECC Level 1 64 kbps synchronous circuits between NIC and 'HLSx' to be used by NIC PY and SY RAS Controller for "BLOCK power generation injection to BC HYDRO system at 'HLSx'". Physical interface shall be C37.94 optical over multimode fibre using ST connectors.

Tele-control Requirements for Telecom:

- Provide ‘HLTx’ SCADA (RTU ‘A’) circuit off FVO and SIO.
- Provide ‘HLTx’ SCADA (RTU ‘B’) circuit off FVO and SIO.
- Provide ‘HLTx’ REMACC circuit(s) off FVO.
- Provide 'HLSx' SCADA circuit off SIC.

Other Requirements:

- 'HLSx' remote access to protective relays (REMACC) and PPIS circuit(s).
- 'HLSx' revenue metering circuit(s).

The detailed telecommunication upgrade works required would be described in the next stage of Facilities study. It is expected that all work would be done by BC Hydro unless otherwise indicated.

The IC is required to install two 48-strand single mode fibre optic cable from HLTx to HLSx.

5.10 Revenue Metering Requirements

- The remote read load profile revenue metering installation should be in accordance with Canada federal regulations and BC Hydro Requirements for Complex Revenue Metering. The latest version of this document is published at BC Hydro’s external website. The revenue metering responsibilities and charges shall be in accordance with Section 10 (10.1 and 10.2). For details about the specific responsibilities, see table on pages.23-26.

- Primary Metering is required. A 3-element metering scheme with 3 CTs and 3 VTs connected L-N (Grd) will be used.

- Main and backup load profile interval meters are required to measure the power delivered. The meters will be programmed for 5 minutes interval and will be remotely read each day by BCH Billing Group using MV-90; the POM shall have a dedicated communications line (BC Hydro’s approved wireless IP solution, landline, or other approved alternative). It should be used for revenue metering only. If there is digital cell phone coverage for data in the site, BCH can supply the IP Wireless Communications Modem equipment.

- The revenue class meters (main and backup) are Measurement Canada (MC) approved and will be supplied and maintained by BC Hydro. The MC approved revenue class instrument transformers (CTs and VTs units) are supplied by IC/PG (IC must submit all technical information for CTs and VTs as

Model/Maker/MC Approval under to BC Hydro prior to purchasing it. And BC Hydro will analyze it.

- If the impedance and losses between the POM and the PODR are significant, the meters will be programmed to account for the line and/or transformer losses between the POM and PODR. The customer or the consultant shall provide the line parameters (and/or power transformer) data signed and stamped by a professional engineer.

- During the planning phase, BCH Revenue Metering department should be contacted to discuss the specifics of the project. The applicant should send drawings to BCH Revenue Metering Department showing the 1-line diagram (SLD) and informing the planned metering scheme, meter cabinet location, as well as any other related document. BC Hydro's Revenue Metering department can be contacted via email: metering.revenue@bchydro.com.

Hereunder are some information about CTs and VTs, which are important as reference for guidance.

Voltage Transformers (Supplied by IC)	3 x VTs (L-Grd) – 80,500-115-115V – To be supplied by PG
Current Transformers (Supplied by IC)	3 x CTs- 800:5-5 A – Ratio – To be supplied by PG

6 Cost Estimate and Schedule

The cost estimate provided for the Interconnection Network Upgrades is a non-binding good-faith cost estimate based on a Class 5, conceptual level estimate. The cost estimate for the Interconnection Network Upgrades required to interconnect the proposed project to BCH Transmission System is $62.18 million (+100%/-35%). The cost estimate includes 35% contingency.

The cost estimate excludes:

- GST
- Book value of decommissioned equipment
- Outage costs (lost revenue)
- Any work at IC's station

- Transmission line from IC's station (HLSx) to BC Hydro's new switching station (HLTx)

The non-binding good faith estimated time to construct is 4 to 5 years after completion of the Interconnection Facilities Study stage and execution of a Standard Generator Interconnection Agreement (SGIA). The Interconnection Facilities Study report will provide greater detail of the Interconnection Network Upgrade requirements along with a Class 3 preliminary estimate (+15%/-10%) and estimated construction timeline for this project.

7 Conclusions

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

- A three-circuit-breaker-ring switching station is required for interconnecting the [redacted] Project. This proposed switching station is close to the IC proposed POI on 1L55 and is tentatively named as [redacted] Terminal Station (HLTx) in this SIS.

- When [redacted] project is connected, the section of 1L55 from HVC tap to the proposed switching station HLTx needs to be uprated to 800 Amps under 30°C ambient temperature.

- A list of subsequent requirements relating to analytical studies, station upgrades, line upgrades, RAS design, protection, control & telecommunication upgrades are stated in detail in this report.

- The cost estimate for the Interconnection Network Upgrades required to interconnect the proposed project to BCH Transmission System is $62.18 million (+100%/-35%). The cost estimate includes 35% contingency. The non-binding good faith estimated time to construct is 4 to 5 years after the execution of the SGIA, which indicates that the IC's proposed COD of July 31, 2026 can not be achieved.

The Interconnection Facilities Study report will provide greater detail of the Interconnection Network Upgrade requirements along with a Class 3 preliminary estimate (+15%/-10%) and estimated construction timeline for this project.