[redacted]

quA-ymn Solar project

Interconnection System Impact Study

Report No: Transmission Planning 2020-009

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British Columbia Hydro and Power Authority

ACKNOWLEDGEMENTS

This System Impact Study report was

Prepared by: Jing Wang, Interconnection Planning

Reviewed by: Sam Li, Interconnection Planning

Approved by: Robert Pan, Manager, Interconnection Planning

Contributors in the respective disciplines:

___ [redacted] ________
Jing Wang, Interconnection Planning

___ [redacted] ________
Steven Small, Stations Planning

[redacted]

Baike Shen, Analytical Studies

[redacted]

Ming Lu, Transmission Line Design

[redacted]

Tyler Scott, Protection Planning

[redacted]

Yong Chen, Control Planning

[redacted]

Parker Moore, Telecom Planning

[redacted]

Soni Proctor, Revenue Metering

Revision Table

Revision Number	Date of Revision	Revised By

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EXECUTIVE SUMMARY

[redacted] the Interconnection Customer (IC), is proposing to build a solar farm near Highland Valley Copper mine in the South Interior region of British Columbia. The solar farm will have four SMA 4200-UP-US inverters for a total capacity of 15 MW. The proposed Point of Interconnection (POI) is a tap on the existing 138 kV circuit 1L55 between Highland (HLD) and Spatsum (STL) substations located 22.5 km from HLD. The maximum injection achievable for this project at the POI is 14.8 MW after accounting for internal losses and service load. The Commercial Operation Date (COD) proposed by the IC is September 30, 2020; however the required network upgrades identified below cannot be completed by that date.

This report documents the evaluation of the system impact of interconnecting the proposed generating facility, and identifies the required system modifications to obtain acceptable system performance with the interconnection of the proposed project. To interconnect the quA-ymn solar project and its facilities to the BCH system, this SIS has identified the following conclusions and requirements:

- No transmission element overload or voltage violation under system normal or single contingencies is identified as a result of adding the quA-ymn solar farm. No transient instability or unacceptable dynamic voltage performance following single system contingencies exists in the area.
- A disconnect switch at the POI will be added by BCH to connect the IC’s tap line. The disconnect switch will be used to isolate the IC’s facilities from the BCH system when needed.
- A WECC Level 3 non-redundant direct transfer trip (DTT) scheme from HLD to the quA-ymn solar farm for protective and non-protective tripping of 1L55 is required to facilitate disconnecting the quA-ymn solar farm under an islanding condition. Three telecom alternatives are stated on page 11, and Power Line Carrier (PLC) between HLD and the collector station QYSX of quA-ymn solar farm is BCH’s recommended solution and used for the cost estimation in this SIS.
- Islanded operation with existing BCH customers is not planned for the quA-ymn solar farm. As a backup to the direct transfer trip, the IC shall provide its own anti-islanding protection to detect an islanding condition and disconnect its facilities from the Transmission System.
- A 0.5 Mvar shunt capacitor bank is required to add at 34.5 kV bus in the quA-ymn solar farm, which is the IC’s responsibility.
- The IC is required to follow the requirements as applicable in the BCH document “60 kV to 500 kV Technical Interconnection Requirements for Power Generators” (TIR) that pertains to this type of asynchronous generation source (i.e. solar).

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 $2.147 million (+100%/-35%), and the estimated time to complete the Interconnection Network Upgrades is approximately 9 months after the project's implementation funding is approved. The work required within the IC facilities or the Revenue Metering facilities is not part of Interconnection Network Upgrades.

Considering the time for completing the identified Network Upgrades and the commissioning work, the IC proposed COD of September 30, 2020 would not be achievable.

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.

TABLE OF CONTENTS

1.0 INTRODUCTION

The project reviewed in this Interconnection System Impact Study (SIS) report is as described in Table 1-1 below.

Table 1-1: Summary Project Information

Project Name	quA-ymn Solar Project		
Interconnection Customer	[redacted]		
Point of Interconnection	A tap on 1L55, 22.5 km from HLD		
IC Proposed COD	September 30, 2020		
Type of Interconnection Service	NRIS ☒	ERIS ☐	
Maximum Power Injection (MW)	14.8(1) (Summer)	14.8(1) (Winter)	
Number of Generator Units	4 Inverters		
Plant Fuel	Solar		

Note: 1. The maximum achievable injection at the POI is 14.8 MW after accounting for internal losses and service load which is lower than the IC proposed 15 MW.

The Interconnection Customer (IC), [redacted], is proposing to develop a solar farm in the South Interior region of British Columbia. This solar farm was previously referred to as [redacted] project. An Interconnection System Impact Study (SIS) was performed in 2018 as a non-tariff study for this project and documented in the report T&S Planning 2018-010 dated June 2018.

In September 2019, the IC revised their application to change the size of individual inverters from 1.875 MW to 3.75 MW, and reduce the total number of solar inverters from 8 to 4. The project is re-named to quA-ymn solar project. To assess the impact of the changes in the inverter size and configuration, an Interconnection System Impact Re-Study is conducted and documented in this report. The re-study is performed in accordance with the tariff requirement.

The inverters to be used in the quA-ymn solar farm are the model 4200-UP-US from the manufacturer SMA, each rated at 4.2 MVA. The maximum active power output from each inverter is capped to 3.75 MW by SMA to limit the farm output to 15 MW. With the inverter change, the total maximum reactive power output from all the inverters reduces to 7.6 Mvar, which is substantially lower than 12 Mvar in the 2018 SIS.

The maximum power (15 MW) generated from all 4 inverter units will first be stepped up to the 34.5 kV level through step-up transformers and then to the 138 kV system through a 17 MVA, 138 kV (Y-gnd) / 34.5 kV (Δ) transformer unit. The power generated from the solar farm will be transmitted through an IC owned 1 km, 138 kV transmission line and into the BCH's system via a tap connection on circuit 1L55, between Highland station (HLD) and Spatsum station (STL). The Point of Interconnection (POI) is located at this tap point which is approximately 22.5 km along 1L55 from HLD. The maximum achievable injection into the BCH system at the POI, after losses, is approximately 14.8 MW. The IC's proposed Commercial Operation Date (COD) for this project is September 30, 2020.

There are three industrial facilities fed by circuit 1L55, Highmont station (HVC), Lower Level Dam station (LLD) and Spatsum station (STL). These load stations are owned by the same customer, Highland Valley Copper. These industrial facilities have more than 100 MW peak demand with large amount of motor loads. Because of their proximity to the solar farm, the load characteristics of these facilities could have a significant impact on the performance of the solar farm.

There are two existing generating stations owned by independent power producers (IPP) in the nearby area. Kwoiek Creek Generating Station (KCH) with a total capacity of 60 MW is connected to HLD via a 72.7 km, 138 kV transmission line 1L57 and Merritt Green Energy generating station (MIG) with a total capacity of 40 MW is connected to Merritt 2 substation (MR2) which is fed by 1L254 from HLD.

HLD is a 138/60 kV substation in the Merritt area. In addition to supplying the industrial customer Highland Valley Copper and interconnecting the IPPs, HLD connects to BC Hydro's Savona (SVA) substation via 1L203 and 1L205, and Nicola (NIC) substation via 1L243. Combined with local load and generation patterns, the Bulk System operating conditions (specifically 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.

The study also considers the impact of generation projects proposed in the South Interior West area. The UNB/ONA Energy Project, a 15 megawatt PV solar generating facility close to NIC, is included in the study.

Figure 1-1 shows the layout and the connection of the quA-ymn solar farm. The direct current power elements within the solar farm have been omitted from the layout. Figure 1-2 shows the geographic location of the quA-ymn Solar Project in the Highland area.

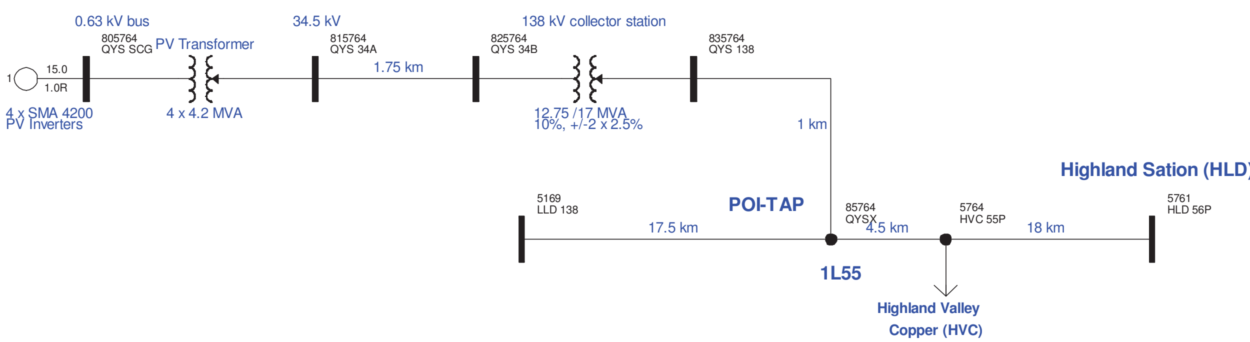


Figure 1-1 – quA-ymn Solar Farm Layout

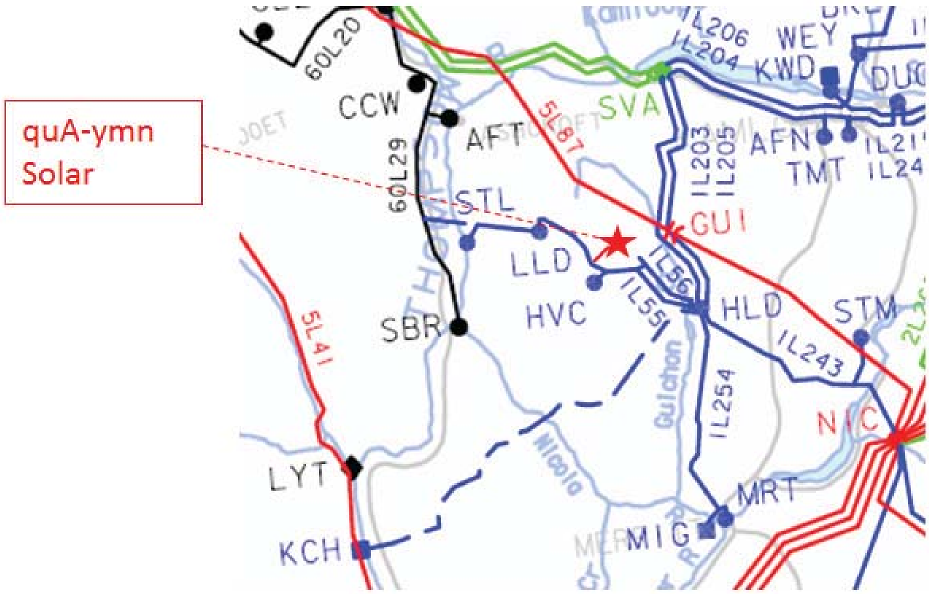


Figure 1-2 - The Geographic Location of quA-ymn in the Highland area

2.0 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. This study will identify constraints and Network Upgrades required for interconnecting the proposed generating project in compliance with the NERC/WECC reliability standards and the BC Hydro transmission planning criteria.

3.0 TERMS OF REFERENCE

This study investigates and addresses the voltage and overloading issues of the transmission network in the vicinity of HLD as a result of the proposed interconnection. Topics studied include equipment thermal loading and rating requirements, system transient stability and voltage stability, transient over-voltages, protection coordination, operation flexibility, telecom requirements and high level requirements for local area protection schemes (LAPS). BCH planning methodology and criteria are used in the studies.

The SIS does not investigate operating restrictions and other factors for possible second contingency outages. Subsequent internal network studies will determine the requirements for reinforcements or operating restrictions/instructions for those kinds of events. Any use of firm or non-firm transmission delivery will require further analysis specific to the transmission service that may be requested later and will be reviewed in a separate study.

The work necessary to implement the network improvements identified in this SIS report will be described in greater detail in the Interconnection Facilities Study report for this project.

4.0 ASSUMPTIONS

The power flow conditions studied include generation, transmission facilities, and load forecasts representing the queue position applicable to this project. Applicable seasonal conditions and the appropriate study years for the study horizon are also incorporated. The 2019 winter and summer load conditions are selected for this study.

This system Impact study was carried out based on the model data and information submitted by the IC to BC Hydro in September 2019 for this project. Reasonable assumptions are made to complete the study and the report, whenever such information is unavailable.

Other key assumptions made for this study are listed as follows.

- A set of tentative voltage ride-through (VRT) and frequency ride-through (FRT) settings that meet the minimum requirements specified in the TIR are assumed for the study purpose. The assumed VRT/FRT settings are detailed in Section 5.3.
- The industry loads at HVC, LLD and STL are represented with static load characteristics. A typical load model with motor dynamics is included for sensitivity study purpose.
- Because no dynamic model information is available for the UNB/ONA energy project, a proxy of UNB/ONA energy project has been made in the dynamic simulations for the quA-ymn Solar project. The performance assessment of the UNB/ONA energy project is beyond the scope of this study and will be studied separately.
- No Surge Arrester (SA) has been modeled to capture maximum possible temporary over-voltage (TOV). SA is only added at critical locations to evaluate energy requirements and potential operation times for extreme TOV conditions.

5.0 SYSTEM STUDIES AND RESULTS

Power flow, short circuit and transient stability studies are carried out to evaluate the impact of the proposed interconnection on the BCH Transmission System. Studies are also performed to determine the protection, control and communication requirements and to evaluate possible over-voltage issues.

5.1 Reactive Power Compensation

The solar farm is required to have capability of providing a range of 0.95 leading to 0.95 lagging power factor as measured at the Point of Interconnection when generating at its maximum power injection. In other words, the quA-ymn solar farm shall be capable of injecting and absorbing reactive power up to 33% of its rated active power, or a ±5 Mvar through the POI.

Load flow studies were performed to determine whether the solar farm is capable of meeting the above requirement after accounting for the reactive power losses within the IC's facility. The results of the simulations provided in the Table 5-1 below indicate that the inverters are able to absorb the required reactive power but inadequate to produce the required amount of reactive power into the system. Thus a 0.5 Mvar shunt capacitor bank at 34.5 kV bus will need to be added as a part of solar farm facility.

The reactive power capability in lagging power factor of the project was assessed under the following assumptions:

- Maximum active power output (15 MW) from the equivalent generator;
- Maximum reactive power output (7.6 Mvar lagging) from the equivalent generator.

The reactive power capability in leading power factor of the project was assessed under the following assumptions:

- Maximum active power output (15 MW) from the equivalent solar generator;
- Maximum reactive power consumption (7.6 Mvar leading) from the equivalent solar generator.

Table 5-1: Reactive Power Capability of quA-ymn solar farm (no shunt capacitor)

Operation	Pgen (MW)	Qgen (Mvar)	Q_{POI} (Mvar)	Gen Bus Voltage (pu)	34.5 kV Bus Voltage (pu)	138 kV Bus Voltage (pu)
Lagging PF (Reactive power injection)	15	7.6	4.5	1.04	1.01	1.01
Leading PF (Reactive power absorption)	15	-7.6	-11.2	0.97	1.00	0.99

5.2 Steady State N-0 and N-1 Power Flows

Steady state pre-outage (N-0) and single contingency (N-1) power flow analyses were performed to evaluate the impacts of integrating the quA-ymn solar project's 14.8 MW power injection on system voltages and transmission elements loadings in the area.

With the quA-ymn Solar project connected, the voltages in the surrounding areas were observed to be within acceptable limits, and no transmission elements overload was observed in the transmission system in steady state system normal (N-0) and steady state single contingency (N-1) conditions.

The voltage levels at nearby key substations and the loading of circuits under system normal (N-0) and applied N-1 conditions are shown in Table 5-2.

Table 5-2: Steady State Power Flow Results for quA-ymn Solar Project

System Load Condition	System configuration	Branch Loading (%)					Bus Voltage (PU)				
		1L203 HLD-SVA	1L205 HLD-SVA	1L243 HLD-STM	1L243 UOS tap-NIC	1L55 HLD-HVC	QYSX POI	LLD 138	HLD 138	SVA 138	NIC 138
2019 LS	System Normal	11	15	15	7	45	0.991	0.988	1.011	1.028	1.019
	Loss of 1L203 (HLD-SVA)	----	23	14	7	45	0.984	0.981	0.994	1.031	1.018
	Loss of 1L243 (HLD-NIC)	13	17	----	----	45	0.985	0.982	1.005	1.027	1.020
2019 HW	System Normal	12	15	30	24	44	0.99	0.987	1.01	1.022	1.025
	Loss of 1L203 (HLD-SVA)	----	23	27	20	44	0.985	0.982	1.005	1.023	1.023
	Loss of 1L243 (HLD-NIC)	12	14	----	----	44	0.98	0.978	1.0	1.021	1.025

Notes:

- ‘HW’ and ‘LS’ stand for heavy winter and light summer, respectively

In addition to the local load and generation patterns, the Bulk System operating conditions, including the dispatch pattern of generation from the Northern Region (NI) and from the South Interior (SI) have some effect on the flows on 1L203, 1L205 and 1L243. The operating conditions with different generation dispatch patterns from NI and SI have been tested and the study conclusions are not affected by this variation.

The area single line diagram is shown in Appendix A of this report.

5.3 Transient Stability Study

A series of transient stability studies under various system operating conditions including the heavy winter case and the light summer case have been performed. The model of the generating project was based on the IC’s data submission and any additional assumptions where the IC’s data was incomplete or inappropriate.

No transient instability phenomenon or unacceptable dynamic voltage performance has been observed based on the studied scenarios and contingencies.

The transient stability study results for 2021 summer light load case are summarized in Table 5-3 below.

Table 5-3: Transient Stability Study Results
(Pre-outage condition: 2021 LS with 14.8 MW Injections from quA-ymn Solar Project)

Case	Outage	3Φ Fault Location	Fault Clearing Time (Cycles)		quA-ymn Solar Farm Performance	Minimum Transient Voltage (p.u.)	Other Non-Islanded Units
			Close End	Far End			
1	1L203/1L205 (HLD – SVA)	Close to HLD	HLD 7	SVA 9	Acceptable	0.93	Acceptable
2	1L203/1L205 (HLD – SVA)	Close to SVA	SVA 7	HLD 9	Acceptable	0.97	Acceptable
3	1L243 (HLD – NIC)	Close to HLD	HLD 7	NIC 9	Acceptable	0.97	Acceptable
4	HLD T2 LV bus	25 kV bus	T2 25kV 60	--	Acceptable	1.0	Acceptable
5	HVC TN HV bus	138 kV side	TN HV 8	--	Acceptable	0.99	Acceptable
6	HVC TN LV bus	13.8 kV side	TN LV 60	--	Acceptable	1.0	Acceptable

The above transient stability study results were derived based on the typical static load characteristics of the nearby industry loads HVC, LLD and STL. To investigate the impact of the load dynamics on the solar farm operation, a typical load model with the effect of motor dynamics was developed for these industrial facilities and a preliminary investigation was conducted for sensitivity study purpose with the motor dynamics taken into consideration. It appears from the investigation that motor load tripping could occur at HVC/LLD/STL and that the quA-ymn solar farm is capable of riding through the critical system disturbance listed in the Table 5-3 if the inverters at quA-ymn solar farm meet the minimum voltage ride through requirement specified in BC Hydro “60 kV to 500 kV Technical Interconnection Requirements For Power Generators” (TIR).

Having adequate voltage ride-through (VRT) and frequency ride-through capabilities (FRT) is critical for the inverter-based resources to reduce likelihood of being unnecessarily tripped in operation. It has been confirmed by the vendor that the VRT/FRT settings of the SMA 4200-UP-US inverters could be configured to meet the requirements stated in the BCH’s TIR.

The study was performed with a set of tentative VRT and FRT settings derived from the VRT/FRT maximum capability curves provided by the vendor. Figure 5-1 shows the tentative VRT/FRT settings curves in comparison to the requirements stated in the TIR.

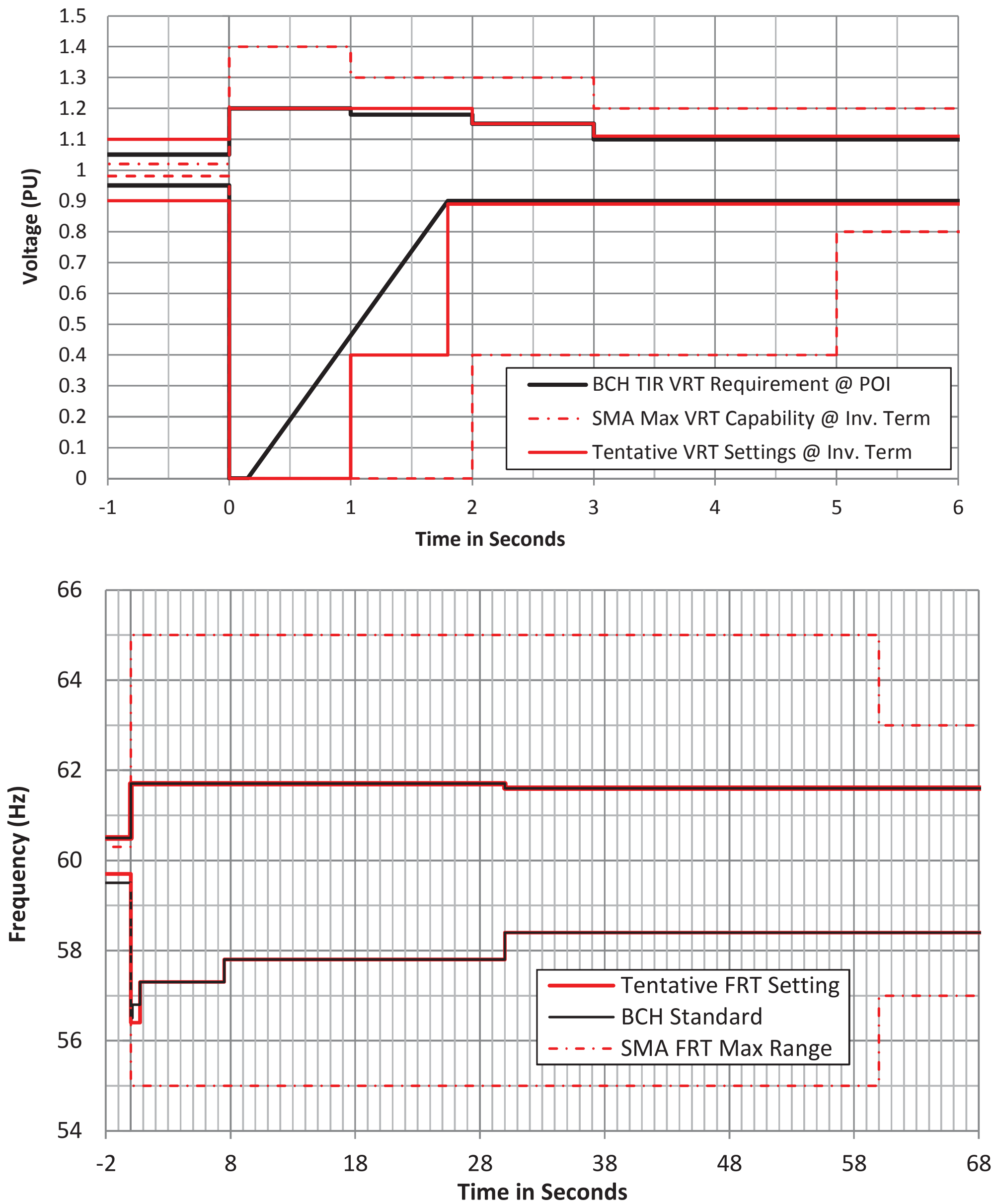


Figure 5-1: Inverter VRT and FRT settings assumed in the study

5.4 Analytical Studies

A system analytical study was performed to investigate the possible temporary over-voltage (TOV) and transformer energization concerns caused by the connection of quA-ymn solar farm.

The following requirements were identified for connecting the quA-ymn solar farm into the transmission network:

- A direct transfer trip (DTT) from HLD to the collector station (QYSX) for protective and non-protective tripping of 1L55. This DTT requirement is described with additional details in Section 5.8 below.
- Functionality of harmonics monitoring at the QYSX HV side.

5.5 Fault Analysis

The short circuit analysis for the System Impact Study is based upon the latest BCH system short circuit model, which includes project equipment and impedances provided by the IC. The model included higher queued projects and planned system reinforcements but excluded lower queued projects. Thevenin impedances, including the ultimate fault levels at POI, are not included in this report but will be made available to the IC upon request.

BCH will work with the IC to provide accurate data as required during the project design phase.

5.6 Transmission Line Upgrade Requirements

No transmission line upgrades has been identified for this project.

At the POI, BCH will design and build the tap that will include a tap structure and a switch structure on the tap side. A 152 kV rated disconnect switch will be installed to isolate the IC's facilities from the BCH system. Additional Right-of-Way (ROW) may be required to accommodate the tap.

As determined in Telecom Requirements in Section 5.8 below, the following four wave traps will need to be added for the Power Line Carrier (PLC) alternative:

- A wave trap on 1L55 between the QYSX tap and the LLD tap.
- A wave trap on the line side of disconnect switch 1D25 of HLD.
- A wave trap on the line side of the HVC POI disconnect switch 1D1L55.
- A wave trap on the line side of the main incoming disconnect switch in QYSX.

5.7 BCH Station Upgrades or Additions

A wave trap on the line side of disconnect switch 1D25 of HLD will be required, as listed in 5.6. No other station upgrades or additions are identified for this project.

5.8 Protection and Control & Telecommunications

Protection

Protection Work Required by BCH:

- Review line protection settings of 1L55 at HLD for the interconnection of the IC's project.
- Revise 1L55 Primary Protection (PYPN) and Secondary Protection (SYPN) to initiate a direct transfer trip (DTT) for protection tripping and non-protection opening of 1L55. A WECC Level 3 tele-protection circuit is required to deliver the DTT signal.

Protection Work Required by the IC:

- The IC will provide entrance protection, power quality protection, redundant protection for the line in accordance with the requirements laid out in BC Hydro "60 kV to 500 kV Technical Interconnection Requirements For Power Generators" (TIR) that pertains to this type of asynchronous generation source (i.e. solar).
- The IC shall provide a model of their generation source, preferably in a table format to be used in an Aspen OneLiner Voltage Controlled Current Source model. This table shall include current output and power factor at a variety of voltage levels. If the inverter is programed to output negative sequence current, this information will be required as well.

Control

Control Work Required by BCH:

- Provide alarm at HLD for the new DTT facilities in accordance with standardized alarm guidelines.
- At BCH Control Centres, re-configure FEPs at SI1 DCP (or ING DCP if satellite is used) and update the existing database and displays at FVO/SIO to accommodate the quA-ymn generation and alarm addition at HLD.
- Update the network model and network application in BCH Control Centres to show the quA-ymn generation.

Control Work Required by the IC:

- The IC is required to provide telemetry and status information via a DNP3 RTU/IED (Distributed Network Protocol 3, Remote Terminal Unit/Intelligent Electronics Device) to the BCH Control Centres in accordance with TIR requirements.
- The IC is responsible to provide a continuously reporting channel to the closest BC Hydro station with appropriate telecom facilities (station to be determined by BC Hydro Telecom). Broadband satellite communications is also an acceptable option provided the performance objective stated in TIR are met.
- The IC is required to install Power Parameter Information System (PPIS) to ensure proper power quality is maintained for on-line, off-line, steady and dynamic states.
- The IC is also responsible for providing a communications link for remote interrogation of protective 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 are subject to BCH review and approval.
- The IC shall provide 1L55 protection event records from 1L55 protection relays to BC Hydro under the following circumstances.
    - Fault on 1L55
    - Relay mis-operation for fault outside 1L55
    - Relay operation due to Power Quality Protection elements

Telecom

The following communication alternatives for the WECC Level 3 non-redundant DTT from HLD to QYSX were considered:

- A fiber optic line on 1L55 from HLD to QYSX was considered but it would be cost prohibitive and is not selected.
- Third party lease was considered, but this option would only be viable when a communication circuit lower than the WECC Level 3 is applicable.
- Power Line Carrier (PLC) between HLD and QYSX.

PLC is the recommended solution. The works under the PLC alternative are described below.

Telecom Work Required by BCH:

Work on 1L55

- Install a wave trap on 1L55 between the QYSX tap and the LLD tap.

Work at HLD

- Install a wave trap on the line side of disconnect switch 1D25.
- Install a line matching unit (LMU) and connect to communications interface on existing CVT.
- Install a single shelf PLC terminal facing QYSX, ABB 600 or equivalent.
- Install a Teleprotection terminal, ABB NSD570 or equivalent.

Work at HVC

- Install a wave trap on the line side of the HVC POI disconnect switch 1D1L55.

Telecom Work Required by the IC at QYSX:

- Install a wave trap on the line side of the main incomer disconnect switch in QYSX station.
- Install a coupling capacitor or CVT with telecom interface.
- Install a LMU.
- Install a single shelf PLC terminal facing HLD, ABB 600 or equivalent.
- Install a Teleprotection terminal compatible with equipment at HLD, ABB NSD570 or equivalent.
- Install a Ku-band satellite terminal to transport SCADA, PPIS and metering circuits to BC Hydro.

The location of the wave traps, coupling capacitors, and other PLC/teleprotection to be installed is shown in the diagram in Appendix B.

5.9 Islanding

Islanded operation with other nearby BCH customers has not been arranged for the quA-ymn Solar farm. A direct transfer trip scheme will be utilized to isolate the solar farm for protective tripping of 1L55. The back-up to the DTT is the solar farm's own anti-islanding protection at QYSX in accordance with the TIR to detect an islanding condition and disconnect its facilities from the system.

5.10 Black Start Capability

BCH does not require the proposed project to have black start (self-start) capability.

However, if the IC desires their facilities to be energized from the BCH system, the IC is required to apply for an Electricity Supply Agreement. Upon receipt of this application, a plant pick-up study would be required to assess the impact of energizing the IC's facilities.

5.11 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 $2.147 million (+100%/-35%). The cost estimate includes 20% contingency.

The estimated time to complete the Interconnection Network Upgrades is approximately 9 months after the project's implementation funding is approved. Considering the time for completing the identified Network Upgrades and the commissioning work, the proposed COD of September 30, 2020 would not be achievable.

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.

6.0 REVENUE METERING

Specific metering information is provided in Table 6-1. Refer to Appendix D for more detailed information.

The estimated Revenue Metering cost is $66,600, which is not included in the network upgrade cost.

Table 6-1: Metering Specific Information

Point-of-Metering	Secondary side of the main power transformer
Voltage Transformers	2 x 34500 – 115 V
Current Transformers	2 X 300 – 5 A

Note:

- The IC shall update the single line diagram showing metering on the secondary side of the power transformer.
- The IC shall update the single line diagram showing key interlocking scheme on the line and load side of the metering equipment.
- The IC shall make sure the there is no station service upstream of the point of metering.

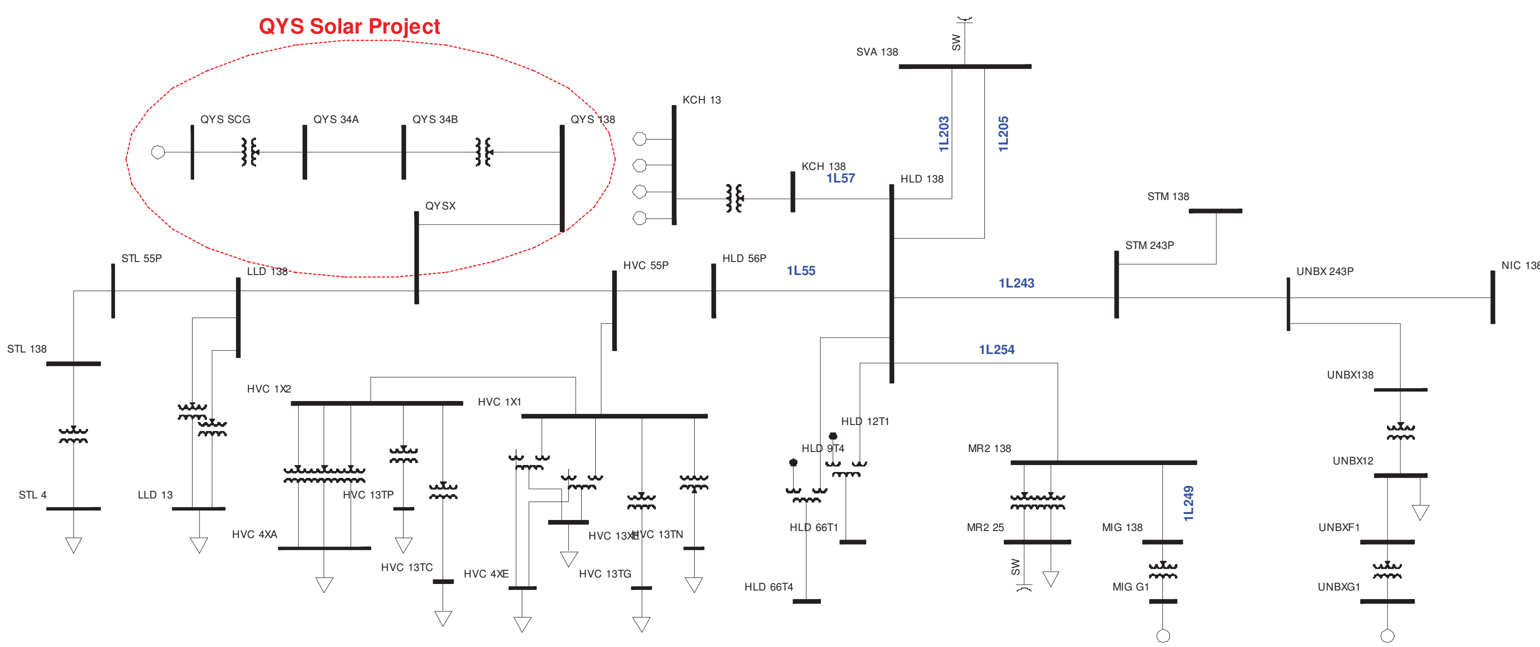
7.0 CONCLUSIONS & DISCUSSION

In order to interconnect the quA-ymn Solar project and its facilities to the BCH Transmission System at the POI, this SIS has identified the following issues and requirements:

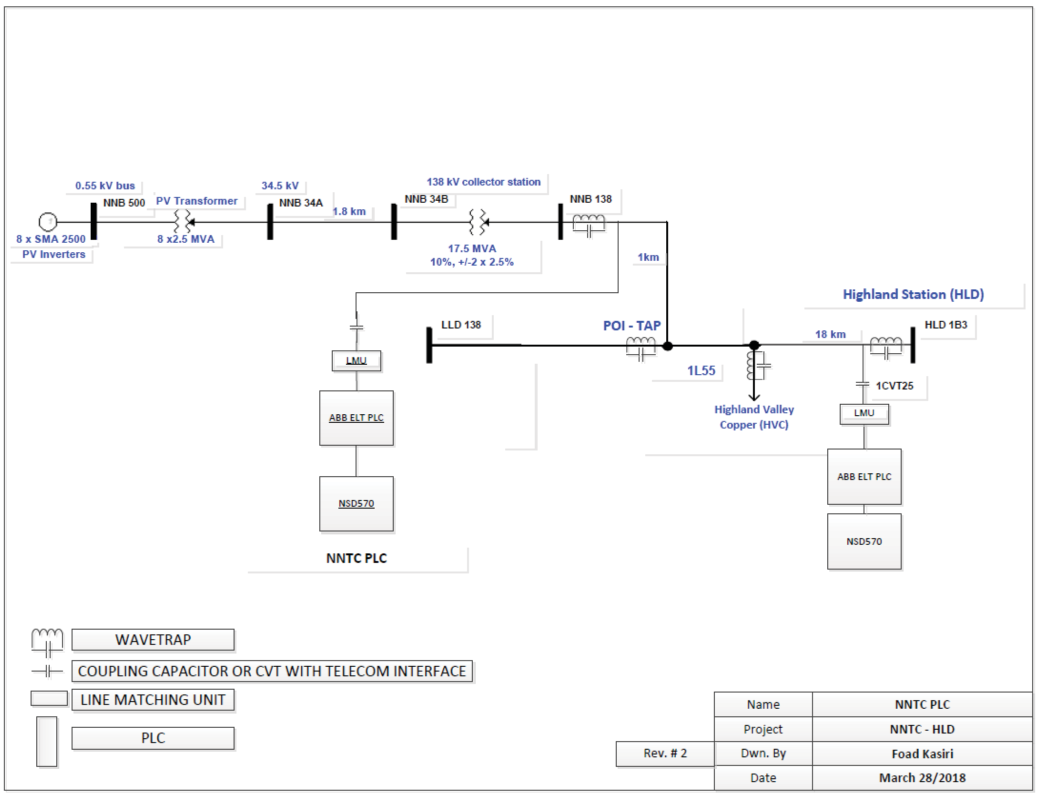
- No transmission element overload or voltage violation under system normal or single contingencies is identified as a result of adding the quA-ymn solar farm. No transient instability or unacceptable dynamic voltage performance following single system contingencies exists in the area.
- A disconnect switch at the POI will be added by BCH to connect the IC's tap line. The disconnect switch will be used to isolate the IC's facilities from the BCH system when needed.
- A WECC Level 3 non-redundant direct transfer trip (DTT) scheme from HLD to the quA-ymn solar farm for protective and non-protective tripping of 1L55 is required to facilitate disconnecting the quA-ymn solar farm under an islanding condition. Three telecom alternatives are described on page 11, and Power Line Carrier (PLC) between HLD and QYSX is BCH's recommended solution and used for the cost estimation in this SIS.
- Islanded operation with existing BCH customers is not planned for the quA-ymn solar farm. As a backup to the direct transfer trip, the IC shall provide its own anti-islanding protection to detect an islanding condition and disconnect its facilities from the Transmission System.
- A 0.5 MVAr shunt capacitor bank is required to add at 34.5 kV bus in the quA-ymn solar farm.
- The IC is required to follow the requirements as applicable in the BCH document "60 kV to 500 kV Technical Interconnection Requirements for Power Generators" (TIR) that pertains to this type of asynchronous generation source (i.e. solar).
- The cost estimate for the Interconnection Network Upgrades required to interconnect the proposed project to BCH Transmission System is $2.147 million (+100%/-35%). The work required within the IC facilities or the Revenue Metering facilities is not part of Interconnection Network Upgrades.
- The estimated time to complete the Interconnection Network Upgrades is approximately 9 months after the project's implementation funding is approved. The proposed COD of September 30, 2020 would not be achievable.

The above conclusions and requirements were derived upon a number of key assumptions as described in Section 4.0.

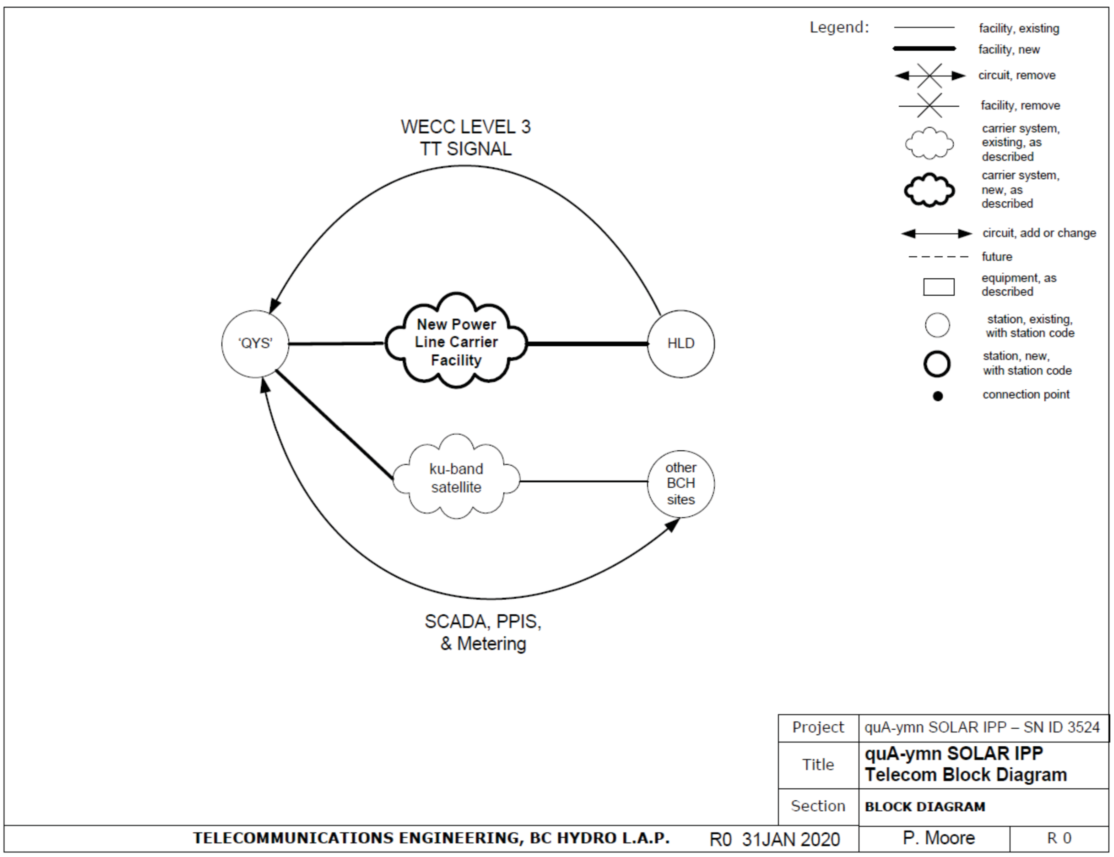
APPENDIX A – Area Single Line Diagram with the IC Project



APPENDIX B – Telecom PLC Diagram



APPENDIX C – Telecom Block Diagram



APPENDIX C – 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 on the BC Hydro's webpage under Forms and Guides. 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.23-25.

Revenue class meters (main and backup) approved and sealed by Measurement Canada (MC) will be installed to register the energy delivered and received from the power generator. The meters will be supplied and maintained by BC Hydro. The main meter will be leased by BCH to the PG. The meters will be programmed for 5 minutes interval and will be remotely read each day by BCH/ABSU Enhanced Billing Group using MV-90.

A 2-element metering scheme with 2 CTs and 2 VTs connected L- L will be used if the power transformer's secondary is delta/ungrounded wye/impedance grounded wye.

The CTs and VTs used on the metering scheme will be supplied by the Power Generator and should be of a model/type approved by Measurement Canada. The CTs and VTs must be pre-approved by BC Hydro's Revenue Metering Department.

For Stand-Alone VTs and CTs, the H1 terminal of the VTs shall be connected on the BC Hydro side of the CTs (upstream of the CTs). The revenue metering VT and CT secondary windings are not permitted to be shared with any other equipment other than the ones listed:

- Check meters;
- Demand or energy management devices;
- Voltmeter, ammeter or other similar instruments; or
- Dedicated Under-frequency relays.

For generation applications, all instrument transformer compartment doors shall be **key interlocked** with a BC Hydro side disconnect device and a Power Generator side disconnect device(s) to prevent opening the instrument transformer compartment door(s) unless all disconnect devices are visibly open. *Where the POM is on the Power Generator side of the power transformer, the BC Hydro side disconnect device shall be on the BC Hydro side of the power transformer to insure no-load losses.*

The PG or its consultant shall provide the line parameters data and the power transformer testing data to BC Hydro if the distance between POI and POM is significant and/or metering is on the secondary side.

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, communication scheme, meter cabinet location, as well as any other metering related document. BC Hydro's Revenue Metering department can be contacted via email: metering.revenue@bchydro.com

