

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

February 28, 2025

[REDACTED]

Dear [REDACTED],

RE: [REDACTED] - Interconnection System Impact Study Report

Enclosed is the Interconnection System Impact Study report for the proposed [REDACTED] project submitted under Attachment M-1: Standard Generator Interconnection Procedures (SGIP) including the Standard Generator Interconnection Agreement (SGIA) 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 System Impact 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 Transmission System. Network Upgrades costs are the responsibility of the Interconnection Customer (IC) for all projects requesting Energy Resource Interconnection Service (ERIS) and not obtaining transmission service for delivering energy.

Please note that [REDACTED] original Interconnection Request in 2014 was incorrectly submitted as a Network Resource Interconnection Service (NRIS). This Interconnection Request actually falls under the ERIS category, as defined in Section 1 of Attachment M-1 to the OATT.

Pursuant to the OATT, BC Hydro will design, procure, construct, install, and own the Network Upgrades. As the Interconnection Customer (IC), [REDACTED] will be responsible for paying the costs of the Network Upgrades.

Cost Estimate

Based on the Interconnection System Impact Study, the non-binding good faith estimated cost (typical accuracy range of +100%/-35%) for Network Upgrades required to interconnect your project is **\$151,000** plus tax.

Major Scope of Work Identified:

- Protection Planning work (protection settings, line configuration, etc.) is required at Capilano Substation, Cypress Substation, Hillcrest Substation and Capilano Pumping Station Substation.
- Review and revise the relay protection settings of the transmission line 60L99 (including 60L66) to accommodate the [REDACTED] project.
- Control Planning work related to telemetry and networking with BC Hydro's Fraser Valley Office and South Interior Office as required to accommodate the new alarms and IPP telemetry points. Update the network model to show the new generators.

Exclusions:

- GST
- Book value of decommissioned equipment
- Outage costs
- Permits

Key Assumptions:

- Construction may be completed by BCH or its contractor(s)
- 3 months of construction
- No expansion of existing station or control building to accommodate new equipment

Key Risks:

- Delays in receiving documentation from [REDACTED]
- Project schedule may be longer than expected, leading to increased costs
- Cost of materials may be affected by market conditions and escalation

Revenue Metering

Please note that as per the System Impact Study, there are no Revenue Metering upgrades required. However, BC Hydro Revenue Metering will need to review [REDACTED] one-line diagrams and perform work on existing Point-of Metering (POM) settings to accommodate changes to interconnect your project. Revenue Metering costs that are attributable to the Interconnection Customer are to be paid in cash and are included in the estimate above. 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 System Impact Study, the non-binding good faith estimated In-Service Date (ISD) for your project's Network Upgrades is April 30, 2025, based on resource availability. To achieve this timeline, we may need to expedite certain activities, including engineering design and procurement of equipment; the expediting of activities may result in increased costs.

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

- Submission of any additional technical data required for the Network Upgrades
- Execution of a Standard Generator Interconnection Agreement
- Financial commitments, as required

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

Next Steps

[REDACTED] previously paid a non-refundable \$15,000 Interconnection Request deposit to validate your Interconnection Request, as well as a \$75,000 System Impact Study deposit. The costs for these items will be reconciled and any remaining amount may either be applied as a credit to your next invoice or refunded to you. In March 2025, we will issue an invoice for the estimated Network Upgrade costs net any credits to be applied.

If you have any questions, please contact me at [REDACTED]

Sincerely,

[REDACTED]

Interconnections Manager, Transmission Generator Interconnections
BC Hydro

Encl.: [REDACTED]_System Impact Study_Report_28Feb2025.pdf

CC:
[REDACTED]

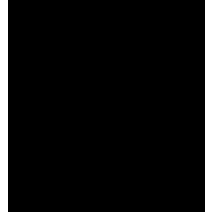


Interconnection System Impact Study

BC Hydro Permit to Practice #: 1002449

BC Hydro Interconnection Queue #: 

Prepared for: 

Prepared by:  
Sr. Engineer, Interconnection Planning

Reviewed by: 
Manager, Interconnection Planning

Accepted by: 
Director, Transmission Assets Planning

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.

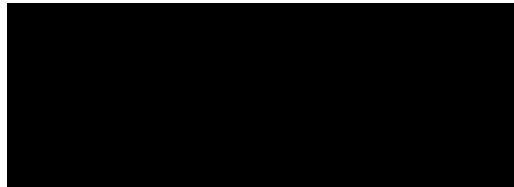
Section:

Entire report
except sections
listed below

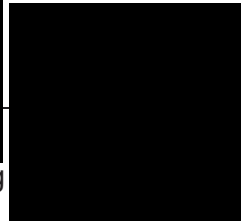
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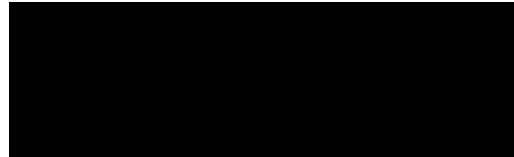
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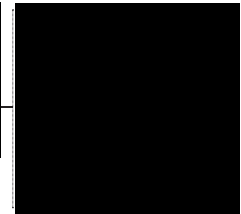
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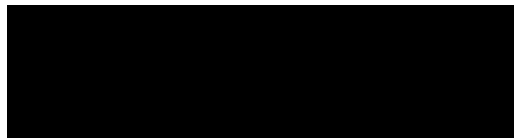
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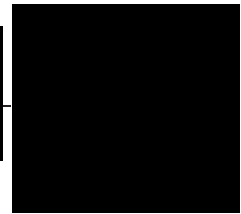
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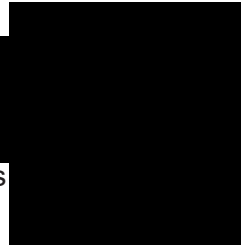
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Volume: 1 of 1

Prepared for: [REDACTED]

Prepared by: [REDACTED]

Title: Sr. Engineer, Interconnection Planning

Checked by: [REDACTED]

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Reviewed by: [REDACTED]

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Related Facilities: 60L99, CPS substation

Additional Metadata: Transmission Planning 2024-158

Revisions

Revision	Date	Description
0	2025 Feb	Initial release

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Acronyms

The following are acronyms used in this report.

BES Bulk Electric System

CAP Capilano Substation

COD Commercial Operation Date

CPS Capilano Pump Station

DCP Data Concentration Point

DDC DNP Data Concentrator

ERIS Energy Resource Interconnection Service

FVO Fraser Valley Office

GLR Glenmore Substation

IC Interconnection Customer

ING Ingledow Substation

NERC North American Electric Reliability Corporation

NRIS Network Resource Interconnection Service

OATT Open Access Transmission Tariff

POI Point of Interconnection

PPIS Power Parameter Information System

RAS Remedial Action Scheme

SIO South Interior Office

SIS System Impact Study

TIR BC Hydro 60 kV to 500 kV Technical Interconnection Requirements for
Power Generators

WECC Western Electricity Coordinating Council

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

1 Introduction

[REDACTED], the Interconnection Customer (IC), proposes to develop the [REDACTED] project to deliver electric energy to BC Hydro (BCH).

The [REDACTED] project is comprised of [REDACTED] generators to be added to the existing Capilano Pumping Station (CPS). There is one existing generator rated 1.77 MW at CPS powered by a hydraulic turbine.

The maximum power injection from CPS into BCH system is 9.6 MW. The IC proposed Commercial Operation Date (COD) is April 2025. The Point of Interconnection (POI) is at the CPS end of the 60 kV CPS tap line.

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

Table 1-1 Project Information

Project Name	[REDACTED]	
Interconnection Customer	[REDACTED]	
Point of Interconnection	At the CPS end of the 60 kV CPS tap line	
IC Proposed COD	April 2025	
Type of Interconnection Service	NRIS <input checked="" type="checkbox"/>	ERIS <input type="checkbox"/>
Maximum Power Injection (MW)	9.6 (Summer)	9.6 (Winter)
Number of Generators	3 x 2.8 MW (new), and 1.77 MW (existing)	
Plant Fuel	Diesel for the new units and hydraulic for the existing unit.	

The CPS station is currently tapped from 60L66 between the BCH owned Glenmore substation (GLR) and Capilano Substation (CAP), 1.5 km from the GLR end. The GLR substation will be decommissioned in summer of 2025 as planned. After the GLR decommission, the existing 60L66 will be part of 60L99. The CPS station is in the North Shore area where a cluster of residential and industrial loads is served by 60 kV lines from WLT and CYP 230/60 kV substations.

At CPS, three new [REDACTED] units [REDACTED] will be installed with the proposed project, and an existing generator unit Gen 003A is in operation. The key parameters are listed in Table 1-2.

Table 1-2 Summary of Generator Information

	Rated MVA	Rated MW	PF (lag/lead)	Terminal Voltage	
[REDACTED]	1.968	1.771	0.9 / 0.95	4.16	(existing)
[REDACTED]	3.5	2.8	0.8 / 0.8	12.47	(new)
[REDACTED]	3.5	2.8	0.8 / 0.8	12.47	(new)
[REDACTED]	3.5	2.8	0.8 / 0.8	12.47	(new)

The IC's station CPS as well as the 60 kV transmission system in the area are shown in Figure 1 and the geographical locations of CPS in the Lower Mainland is shown in Figure 2. The project and adjacent transmission system single line diagram is presented in Appendix A. The [redacted] project has two main power transformers that transfer the plant power output collected at its 12 kV bus to its 60 kV bus then to BCH 60 kV system.

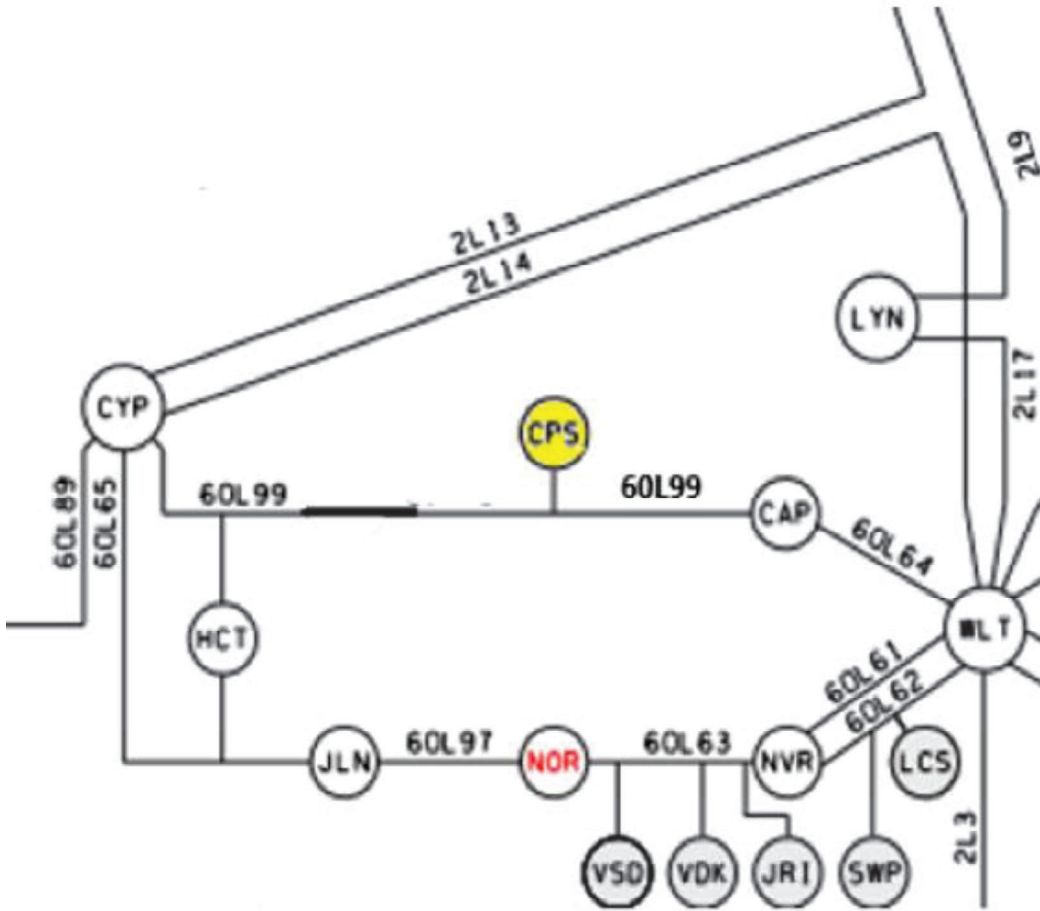


Figure 1 CPS and Adjacent Transmission System

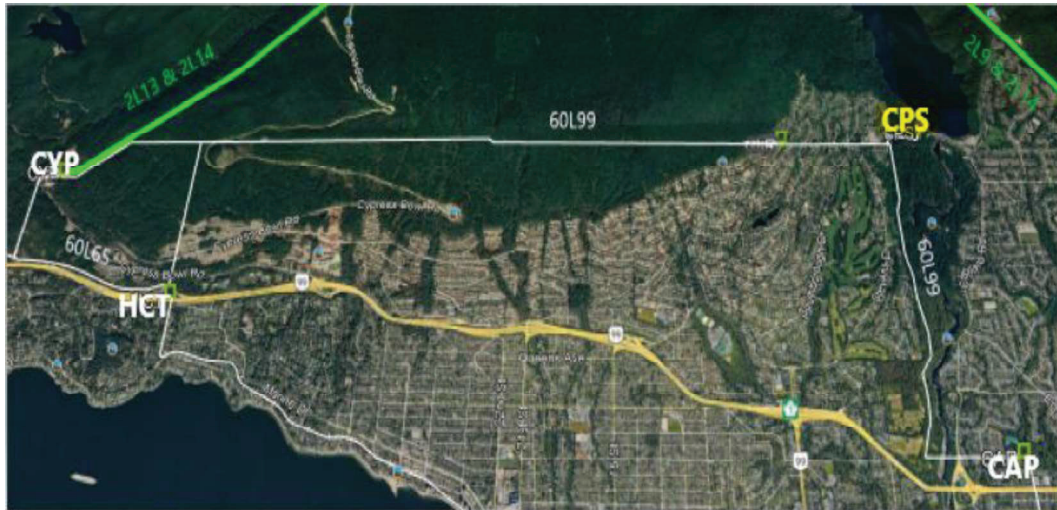


Figure 2 Regional Location of the [REDACTED] project

2 Purpose of Study

The purpose of this SIS is to assess the impact of the interconnection of the proposed project on the BC Hydro transmission system per BC Hydro’s Open Access Transmission Tariff (OATT). This study is to identify any constraints and 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, as well as the BC Hydro 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.

3 Scope of Study

This SIS investigates and addresses the voltage and overloading issues of the transmission system in the vicinity of the [REDACTED] for the long-term planning horizon as a result of the proposed [REDACTED]. 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

This study concludes that with [redacted] project connected to the system, there will be no overloading in the transmission system under system normal (N-0 or P0) and N-1 (or P1) contingency conditions.

Table 5-1 Summary of Branch Loading Analysis Results

Case	IC's Power Injection at POI (MW)	Contingency		Line/Equipment Loading (Percentage of The Line Rating)			
		Categories	Cases & Description	60L99 CPS - CAP	60L99 CPS - HCT	60L64 CAP - WLT	6L65 CYP - JLN
25 LS	9.6	Summer Rating (MVA)		75.9	75.9	80.7	75.9
		P0	1. System normal	36	27	11	44
		P1	2. 60L64 tripped	24	18	N/A	49
25 HS	9.6	N-1	3. 60L65 tripped	49	39	24	N/A
		P0	4. System normal	44	34	9	59
		P1	5. 60L64 tripped	38	30	N/A	65
25 HW	9.6	P1	6. 60L65 tripped	66	56	27	N/A
		Winter Rating (MVA)		83.1	83.1	100.3	97.7
		P0	7. System normal	40	30	7	45
25 HW	9.6	P1	8. 60L64 tripped	48	39	N/A	43
		P1	9. 60L65 tripped	61	52	11	N/A

Note: N/A means not applicable.

5.1.2 Steady State Voltage Analysis

With the connection of the IC's project, the voltage performance under system normal condition and single contingencies is acceptable for all the studied cases. Table 5-2 shows a summary of steady-state voltage performance under various system conditions and contingencies. No voltage violation is observed for these system conditions.

Table 5-2 Summary of Steady-State Voltage Study Results

Case	IC's Power Injection at POI (MW)	Contingency		Bus Voltage (pu)				
		Cat.	Cases & Description	CPS 60kV	CAP 60 kV	WLT 60 kV	HCT 60 kV	CYP 60 kV
25 LS	9.6	P0	1. System normal	1.06	1.06	1.05	1.07	1.07
		P1	2. 60L64 tripped	1.06	1.06	1.04	1.07	1.07
			3. 60L65 tripped	1.06	1.05	1.05	1.06	1.07
25 HS	9.6	P0	4. System normal	1.06	1.05	1.05	1.07	1.08
		P1	5. 60L64 tripped	1.06	1.05	1.05	1.07	1.08
			6. 60L65 tripped	1.05	1.05	1.04	1.03	1.08

25 HW	9.6	P0	7. System normal	1.05	1.05	1.05	1.06	1.06
		P1	8. 60L64 tripped	1.04	1.04	1.05	1.06	1.06
			9. 60L65 tripped	1.05	1.04	1.04	1.03	1.07

Note: N/A means not applicable.

5.2 Transient Stability Study

Transient stability studies have been performed using the 2025 heavy summer base cases to assess the impact of the 9.6 MW maximum power injections from proposed [REDACTED] project on the transmission network in vicinity area. No transient instability phenomenon and transient voltage violations have been observed based on the studied scenarios and contingencies.

If unexpected contingencies cause the generator to slip, the IC's facility must be able to detect the slipping conditions quickly and isolate the generating units from the BCH system. The expected slip center location would be located inside the IC's facilities.

A summary of the transient stability studies for 2025 heavy summer load conditions is provided in Table 5-3.

Table 5-3 Transient stability study results

System Base Case	Study Cases & Contingencies		Fault Locations	Fault Clearing Time (Cycles)		Generation Shedding Required	Transient Stability Performance
				Close End	Far End		
25 HS	1	60L64	At CAP end	8	28	No	Acceptable
	2	60L64	85% of the line from CAP	8 (WLT end)	23 (CAP end)	No	Acceptable
	3	60L65	At CYP end	47	28	No	Acceptable
	4	60L65 with 60L64 already out-of-service	At CYP end	47	28	No	Acceptable

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

The two entrance 60/12.5 kV transformers currently at the CPS substation have Δ/Y configurations, which do not align with the requirements defined in the BC Hydro's TIR. Section 5.4.2 (Existing Installations) states "Transformer replacement or additional equipment may be required for load substations planning to install generators, to avoid operating with an ungrounded system. If a delta configuration on the HV side is permitted, protection updates may also be necessary."

In this case, under/over voltage and frequency power quality protections have been installed to mitigate the delta configuration on the HV side of the transformers. These protections will separate the CPS generation from 60L69 if voltage and/or frequency are measured outside the setting limits.

BC Hydro's operational experience indicates that the current power quality protection at CPS has not shown any transient overvoltage (TOV) issues with the existing transformer configuration. Therefore, the existing delta configuration on the high-voltage side of the transformers is acceptable for the CPS substation. Transformer replacement or the addition of grounding banks on the HV side is not required. No further system upgrade is identified from the analytical perspective.

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 close to the POI (at the nearest BCH substation), are not included in this report but will be made available to the IC upon request.

5.6 Remedial Action Scheme

The interconnection of [REDACTED] project has no material impact on the BC Hydro bulk system performance, and therefore no additional RAS function is required for interconnecting the [REDACTED].

5.7 Station Upgrade Requirements

No Transmission Station upgrade is required for this project.

5.8 Protection, Control and Telecommunications

5.8.1 Protection Upgrade Requirement

In order to interconnect the new generators at CPS, line relay protection settings for 60L65 and 60L99 are required to be reviewed and revised.

5.8.2 Control Upgrade Requirement

The IC will provide SCADA data reporting to FVO/SIO in accordance with the TIR. Communication from CPS to ING Data Concentration Point (DCP) (or alternatively commercial IP communications to Edm DNP Data Concentrator (DDC)) is required to meet the performance objective stated in the TIR. The existing dialup telephone channel may not be reused.

The IC is responsible for providing a minimum IP communications link for remote interrogation of Power Parameter Information System (PPIS) equipment by BCH servers per the TIR. Examples of communication media include commercial cellular, satellite, and internet VPN. Communications selection is subject to BCH review and approval.

The IC is responsible for providing a PPIS meter, connected to a suitable high voltage source for harmonics and power quality metering. The currently approved measurement devices include Power Measurement ION 9000 or Schweitzer Engineering Labs SEL 735. Equipment selection is subject to BCH review and approval.

5.8.3 Telecommunication Upgrade Requirement

It is assumed that a cellular wireless modem to carry the PPIS circuit would be furnished.

No Telecommunication upgrade is required in the transmission system for this project.

5.9 Revenue Metering Requirements

No Revenue Metering upgrade is required in the transmission system for this project.

6 Cost Estimate

A non-binding good faith cost estimate and estimated schedule 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] project to the BC Hydro Transmission System at the POI, this SIS has identified the following conclusions and requirements:

- No unacceptable equipment overloading conditions in the Transmission System were observed in the power flow analysis due to the [REDACTED] project under system normal and contingency conditions.
- No unacceptable voltage violations in the transmission system were observed in the power flow and transient stability simulations due to the [REDACTED] project under system normal and contingency conditions.
- The IC is required to install out-of-step protection to detect their generating units out-of-step condition and isolate the generators from the BC Hydro system. The swing centers are expected within the IC's facilities.
- The generating units at CPS are not allowed to supply an islanded region which includes other BCH loads. The IC is required to provide anti-islanding protection (such as power quality type) within their facility to disconnect their generators from the system, which should help to prevent/mitigate possible inadvertent islanding while still connected with other BCH customers.
- The relay protection settings of the transmission line 60L99 (including 60L66) need to be reviewed and revised to accommodate the [REDACTED] project.
- The IC shall provide SCADA data reporting to BCH Control Centres in accordance with the BCH document "60 kV to 500 kV Technical Interconnection Requirements for Power Generators" (TIR).
- The IC is responsible for providing a communications link for remote interrogation of PPIS equipment by BCH servers.
- The IC shall install PPIS to ensure proper power quality is maintained for on-line, off-line, steady and dynamic states. The currently approved measurement devices include Power Measurement ION 9000 or Schweitzer Engineering Labs SEL 735.

Appendix A: The Project and Adjacent Transmission System Single Line Diagram

