Kwalsa Phase II Project (Big Silver)

System Impact Study Addendum

May 20, 2016

This is an addendum to the System Impact Study Report (No. T&S Planning2012-004 Kwalsa Phase II Project Interconnection System Impact Study) dated August, 2012.

Subsequent to the Interconnection System Impact Study report (Report No. T&S Planning 2012-004) dated August 2012, [redacted] the Interconnection Customer (IC), revised its plant design and the units' parameters in a new submission for Big Silver which is one of the generating sites in the Kwalsa Phase II project.

The IC proposed to install four 11 MW (12.25 MVA) units at Big Silver instead of the IC's originally proposed one 6.816 MVA and three 13.56 MVA units. BCH's Upper Harrison Terminal station (UHT) is the designated Point of Interconnection (POI). The total power injection to the BC Hydro system at the POI from the Kwalsa Phase II project is 83.2 MW, which remains unchanged. The proposed commercial operation date (COD) for the Big Silver site is November 1, 2016. A restudy was performed and the results are documented in this addendum.

For the Big Silver units changes, it has been concluded in this restudy that no additional network upgrades are required beyond what have already been identified in the 2012 report (T&S Planning2012-004).

It has been identified in this restudy that UHT substation has the existing high ground potential rising (GPR) of ~ 9 kV which exceeds BC Hydro's allowable 5kV limit. BC Hydro is investigating the high GPR issue and will determine whether or not some modifications in the station will be required. Also to protect workers in UHT, touch and step potential will be studied and necessary modifications will be done if required. The IC is advised to review potential high GPR issues on its sites as well.

In the previous studies for this project, it was planned that the transmission line 2L90 between Bridge River Terminal (BRT) and Kelly Lake Station (KLY) would be upgraded and put in service before the Kwalsa Phase II project, but the upgrade project was later delayed and has not been in service. In this re-study, the thermal ratings of the existing 2L90 were used and generation restriction at BCH's Bridge River plants is used to mitigate the transmission constraints.

As a result of the status change of the 2L90 thermal upgrade project, the assumption in the third paragraph under Section 4 of the 2012 SIS report is no longer valid and need to be disregarded. And in the 2012 SIS report, the first bullet of the conclusions in the Executive Summary and the same conclusion in the Conclusion & Discussion section:

> *"No BCH transmission lines or substations need to be upgraded or added to accommodate the subject project."*
>
> *Will be superseded by the conclusion below:*
>
> *"Under the system normal condition, 2L90 can be overloaded during some generation and load scenarios. To prevent the overloading, generation restriction at BCH's Bridge River #1 and #2 power plants will be needed as a mitigating solution."*

With reduced generation outputs at Bridge River #1 and #2 power plants, the loading conditions in the Bridge River area transmission network are different from what are described in Sections 5.1 and 5.2 and in Appendixes A and D, but are generally less constrained. No update of those sections or the Appendixes was chosen in this addendum.

The IC's 138 kV transmission lines associated with connecting BSV to the IC's 138 kV transmission system in the new submission are slight different from those in the 2012 study. The sentences in the third paragraph of the Executive Summary and the same sentences in the last paragraph of Introduction of the 2012 SIS report:

> *"TWY will be connected to the existing 138kV line from KWL to Tipella generating station (TPA) at TPA via an 8 km overhead line. BSV will be radially connected to TWY via a 4 km submarine cable and two overhead line segments (10 and 16 km)."*
>
> *Will be superseded by the following sentences:*
>
> *"BSV will be radially connected to TWY via a 4.3 km submarine cable and two overhead line segments (8.3 and 14.8 km). TWY is connected to the 138kV line from KWL to Tipella generating station (TPA) at TPA via a 7.3 km overhead line."*

The Interconnection Facilities Study (IFS) report TGI-2010-A080-FS-R1 contains greater details of the Interconnection Network Upgrade requirements, associated cost estimates and estimated construction timeline for this project. The IFS report may need to be updated.

An update of the Power Flow and Dynamic Models and Data for Big Silver is listed below in Appendix, and supersedes the Big Silver's model and data in Appendix C in the previous SIS report (T&S Planning2012-004).

Appendix: Generator and exciter models and parameters

Table 1 - Generator G1-G4 each: Ratings 12.225 MVA, 11.0 MW, 13.8 kV; +0.9, -0.85 pf

Unit	Model	T'do	T"do	T'qo	T"qo	H	D	Xd	Xq	X'd
G1-G4	GENTPJU1	3.34	0.02	0.3	0.07	1.11	0	1.253	0.713	0.266
		X'q	X"d	X"q	Xi	$S_{G1.0}$	$S_{G1.2}$	K_{is}		
		0.703	0.216	0.276	0.113	0.0275	0.3188	0		

Table 2 - Excitation System model: using submitted model AC8B (parameters as submitted or adjusted where necessary)

Unit	Model	Tr	Kp	Ki	Kd	Td	Vpidmax	Vpidmin	Ka	Ta	
G1-G4	AC8B	0.0	140.	167.	32.	0.02	99.	-99.	1.0	0.004	
VRmax	VRmin	Kc	Kd	Ke	Te	VFEmax	VFEmin	E1	S(E1)	E2	S(E2)
33.	-27.	0.65	0.4	1.0	0.62	99.	0.	4.98	0.12	6.65	1.17

Compensator COMP – at exciter input, due to multiple units on same bus (typical setting).

Unit	Model	Xe
G1-G4	COMP	-0.05

[redacted]

Kwalsa Phase II Project

Interconnection System Impact Study

Report No: T&S Planning2012-004

August 2012

Revision 0

British Columbia Hydro and Power Authority

ACKNOWLEDGEMENTS

This report was prepared and reviewed by T&D, Interconnection Planning and approved by both Interconnection Planning and Transmission Generator Interconnections.

Revision Table

Revision Number	Date of Revision	Revised By

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EXECUTIVE SUMMARY

The Interconnection Customer (IC), [redacted] proposes to develop the Kwalsa Phase II Hydroelectric Project in the Upper Harrison area of British Columbian order to deliver electric energy to BC Hydro (BCH) through the 2008 Clean Power Call (CPC). In April 2012, the IC resubmitted data and changed the number of generating stations from four to three.

Based on the IC's data resubmission in 2012, this report documents the evaluation of the system impact of interconnecting the proposed generating facilities and identifies the required system modifications to obtain acceptable system performance with the interconnection of the subject project. This report supersedes the BCH's report ASP2010-T048 that was based on the IC's initial data submission in 2010.

The subject project is comprised of three generating stations: NW Stave River station (NWS), Tretheway Creek station (TWY) and Big Silver Creek station (BSV). NWS will be tapped onto the existing 138kV line from Harrison Hydro LP's Kwalsa substation (KWL) to Lamont generating station (LMN) at approximately 25.6 km away from KWL. TWY will be connected to the existing 138kV line from KWL to Tipella generating station (TPA) at TPA via an 8 km overhead line. BSV will be radially connected to TWY via a 4 km submarine cable and two overhead line segments (10 and 16 km). BCH's Upper Harrison Terminal station (UHT) is the designated Point of Interconnection (POI). The maximum power injection to the BCH system is 83.2 MW. The proposed Commercial Operation Dates (CODs) are December 1, 2013 for NWS, December 1, 2015 for TWY and November 1, 2016 for BSV.

To interconnect the subject project to the BCH Transmission System, this System Impact Study (SIS) has identified the following conclusions:

- No BCH transmission lines or substations need to be upgraded or added to accommodate the subject project.
- Interconnection of the subject project and other nearby CPC projects can cause marginal (1%) overload on Rosedale station (ROS) transformer T1 under system normal condition. Generation redispatch by operators will be needed to remove the overload if it does occur.
- After loss of one single transmission facility, BCH's transformers ROS T1 and Bridge River Terminal (BRT) T4 and several transmission circuits such as 3L5 UHT-ROS can be overloaded. The existing Bridge River system generation shedding scheme will be relied on to resolve the overload. The subject project will be included in the generation shedding scheme.
- The IC's units and some BCH generating units in the Bridge River area may lose stability after a 3-phase fault in the area. Generation shedding through the above mentioned Bridge River area scheme is needed in order to achieve acceptable dynamic performance. The IC is also required to provide out of step protection at their site to trip the slipping units if adverse system conditions cause an unacceptable swing.
- Power quality protection will be required to trip the IC's plants under islanded conditions.
- Based upon the previous Interconnection Facilities Study report (TGI-2010-A080-FS-R1) released in February 2011, the +/- 20% cost estimate for Interconnection Network Upgrades required to interconnect the proposed project to the BCH Transmission System is $ 368, 000 and the estimated time to complete the Interconnection Network Upgrades is 6 months after project approval.

The Interconnection Facilities Study (IFS) report TGI-2010-A080-FS-R1 contains greater details of the Interconnection Network Upgrade requirements, associated cost estimates and estimated construction timeline for this project. The IFS report may need to be updated.

The work required within the IC facilities is not part of Interconnection Network Upgrades.

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1.0 INTRODUCTION

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

Table 1. Summary Project Information

Project Name	Kwalsa Phase II	
Interconnection Customer	[redacted]	
Point of Interconnection (POI)	Upper Harrison Terminal station (UHT)	
IC Proposed COD	See details below.	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	83.2 (summer)	83.2 (winter)
Number of Generator Units	9	
Plant Fuel	Hydro	

The Interconnection Customer (IC), [redacted] proposes to develop the Kwalsa Phase II Hydroelectric project in the Upper Harrison area to deliver electric energy to BC Hydro (BCH) through the 2008 Clean Power Call (CPC). According to the data resubmission in 2012, the s Kwalsa Phase II Hydrolectric project is comprised of three generating stations, down from four: NW Stave Creek, Tretheway Creek and Big Silver Creek stations. The details of these three stations are as follows:

- Big Silver Creek station (BSV) consists of one 6.816 MVA and three 13.56 MVA units, each with 0.9/0.9 leading and lagging power factors. The proposed COD is November 1, 2016.
- Tretheway Creek station (TWY) consists of two 12.973 MVA units with a rated power factor of 0.9 (lagging). The proposed COD is December 1, 2015.
- NW Stave Creek station (NWS) consists of two 9.035 MVA units and one 3.427MVA unit with a rated power factor of 0.9 (lagging). The IC proposed COD is December 1, 2013.

The units at each station will be stepped-up to 138kV and connected to Harrison Hydro LP's Kwalsa substation (KWL). NWS will be tapped onto the existing 138kV line from KWL to Lamont generating station (LMN) at approximately 25.6 km away from KWL. TWY will be connected to the existing 138kV line from KWL to Tipella generating station (TPA) at TPA via 8 km overhead line. BSV will be radially connected to TWY via a 4 km submarine cable and two overhead line segments (10 and 16 km). At KWL, the generation outputs are stepped-up to 360kV and then fed to the adjacent POI, BCH's UHT station. In order to accommodate the subject project, the IC will build the third 138-360kV transformer at KWL. Figure 1 below shows the connection of Kwalsa Phase II hydro Electric project and some other existing or future hydro projects, which as a whole is denoted as Upper Harrison generation cluster.

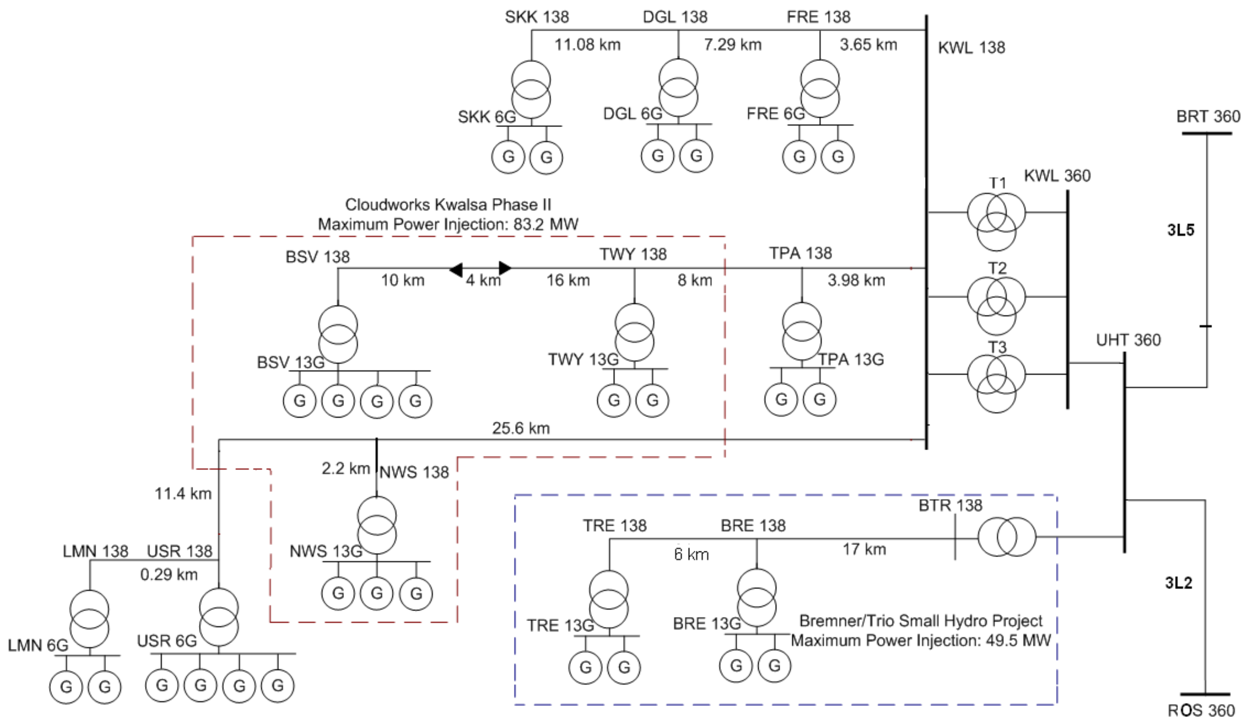

Figure 1 – The Kwalsa Phase II Hydroelectric Project Interconnection Diagram

2.0 PURPOSE OF STUDY

The purpose of this SIS is to assess the impact of the proposed interconnection on the BCH Transmission System. This study will identify constraints and Network Upgrades required for interconnecting the proposed generating project in compliance with the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards and the BCH transmission planning criteria.

3.0 TERMS OF REFERENCE

This study investigates and addresses the overloading, voltage deviation and stability issues of the transmission network in the North Coast area 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, operating flexibility, telecom requirements and high level requirements for Remedial Action Schemes (RAS). 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. Determination of any upgrades on the IC's facilities is beyond the SIS scope.

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 study is carried out based on the updated model, data and information submitted by the IC in April 2012. The power flow conditions studied include generation, load forecasts and transmission system reinforcements representing the queue position of the subject project. Applicable seasonal conditions and the appropriate study years for the study horizon are incorporated.

The export to US is set at the firm transfer level (230MW). All the Lower Mainland including Bridge River area generating plants (except Burrard Thermal) are dispatched at their maximum continuous rating (MCR) levels. If any violations are identified after a single contingency, the Lower Mainland generation may be reduced to Effective load carrying capacity (ELCC) levels or lower to identify the need for system reinforcement.

The transmission line 2L90 from Bridge River Terminal (BRT) to Kelly Lake Station (KLY) will have a thermal upgrade project completed around 2013. After the upgrade, the line can be operated at 90°C, which translates to 1010 Amps in summer and 1285 Amps in winter.

5.0 SYSTEM STUDIES AND RESULTS

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

5.1 Steady State Power Flow Analysis

A series of pre-contingency and single contingency (i.e., N-1) studies have been conducted to check to assess the impact of the proposed interconnection under three load conditions: 2017 light summer (LS) load, 2017 heavy summer (HS) load and 2016 heavy winter (HW) load. The details can be found in Appendix A.

In pre-contingency power flows, marginal (3%) thermal overload occurs on Rosedale station (ROS) 360-230kV transformer T1 in summer. This overload is caused by interconnection of Kwalsa Phase II and other nearby generation projects. The original SIS for the subject project in 2010 mentioned that this overload would be resolved by a network upgrade project in Bridge River area but that upgrade will not be done. BCH's subsequent review of the historical outputs of Bridge River area hydroelectric plants showed that a more realistic overload on ROS T1 is 1%. This level of overload can be mitigated by manual generation redispatch via system operators.

Some single contingency outages can cause voltage violation at ROS bus as well as overload on a number of facilities including transformers ROS T1, BRT T4, transmission lines 3L5 UHT-ROS and 2L90

BRT-KLY. The existing Bridge River system generation shedding scheme will continue to be relied on to resolve the single contingency overloads and voltage violations. The Kwalsa Phase II Hydroelectric project will be included in this generation shedding scheme.

5.2 Transient Stability Study

A series of transient stability studies under various system operating conditions have been performed. The results for 2017 summer light load without and with generation shedding are listed Appendix B.

Addition of the Kwalsa Phase II project to the area will stress the local transmission system and worsen the dynamic performance. Under several studied single contingencies, the existing plants of Upper Harrison generation cluster, Kwalsa Phase II and Bremner Trio small hydro plant would go unstable if generation is not shed. The existing BCH plants BR1, BR2 and WAH would also go unstable under severe contingencies. Generation shedding through the Bridge River system generation shedding scheme is required to achieve acceptable system dynamic performance.

As a common practice, out of step protection also needs to be provided by the IC at their facilities to trip their units if unexpected contingencies cause the units to slip.

5.3 Analytical Studies

An operational issue needs to be paid attention to in the energization of the third transformer at KWL. Simultaneous energization of KWL transformers could be done with UHT circuit breakers 3CB3 and 3CB4 after these breakers are equipped with point-on-wave (POW) controllers in late 2012. Use of UHT 3CB3 and 3CB4 for simultaneous energization of KWL transformers must only be restricted to cases when the transformers to be energized are the same as (or a subset of) the transformers that are previously de-energized with UHT 3CB3 and 3CB4. Any transformer that is not in the last de-energization action and needs to be energized must only do so with its own 360kV disconnect after the simultaneous energization of other transformers. The above restrictions are based on the assumption that the POW controllers to be installed have remnant flux calculation feature that warrants usage of an optimized energization strategy. If this assumption fails, a different strategy will be adopted that provides non-optimal but consistent performance regardless of the configuration of transformers to be energized. The above restrictions will no longer apply.

In cases when the POW controllers are out of service, single transformer energization by means of using 360kV disconnects is mandatory to avoid significant disturbances at UHT and ROS buses.

5.4 Fault Analysis

The short circuit analysis for the System Impact Study is based upon the latest BCH system 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 Upgrades

No BCH transmission line upgrade is planned for accommodating the interconnection of the subject project.

5.7 BCH Station Upgrades or Additions

No BCH station reinforcements are required for interconnecting the subject project.

5.8 Protection and Control & Telecommunications

(1) <u>Protection Requirements:</u>

The IC's units will be automatically included in the existing Bridge River system generation shedding scheme. Since this scheme sheds units by opening the 138kV circuit breakers at KWL, it covers all the units connected along the three 138kV lines from KWL.

The IC needs to provide entrance protection in accordance with the BC Hydro 60kV to 500 kV Technical Interconnection Requirements for Power Generators (TIR).

The IC will provide out of step protection. BCH can provide swing plots to assist with setting of out-of-step protection.

The IC will provide power quality protection to address power quality and anti-islanding issues.

BC Hydro will review line 3L2 and 3L5 protection settings at UHT, ROS and BRT and revise as necessary.

(2) <u>Control Requirements:</u>

The IC will provide the required telemetry and status information (per TIR) via a Distributed Network Protocol (DNP) 3.0 remote terminal unit (RTU). The telemetry and status information is to be reported to BCH's Fraser Valley Office (FVO) and Vernon control center (SIO) via continuous communications. The IC is responsible for providing a continuous telecommunication channel (minimum 2400 bps) from their site to BCH's UHT station with appropriate telecom facilities.

From UHT the telemetry and status information will be routed to the Ingledow data collection point (ING DCP) and connected directly to the front end processors (FEPs). BCH will reconfigure the FEPs at ING to accommodate the new project. BCH will update the database and displays at FVO and SIO to include the telemetry and status information of the new project, update the alarm additions and update network model to show the new generators.

(3) Telecommunication Requirements:

As indicated in section (2), the IC will provide the continuous channel from their site to UHT.

Assume spare capacity is available on BCH's existing telecommunication equipment. BCH will install the required fibre optic termination equipment and modems at UHT. BCH will also install the required communication interface cards at the existing Digital Access and Cross-connect System (DACS) equipments at UHT and ING.

5.9 Islanding

Islanded operation is not arranged for this project. Power quality protection will be required at the generating units to detect abnormal system conditions such as under/over voltage and under/over frequency and subsequently trip the units. The settings of these protective relays must conform to existing BCH practice for generating plants so that the generator will not trip for normal ranges of voltages and frequencies.

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.

5.11 Other issues

(1) Operation study for finalizing generation shedding details will be performed later. Operating Orders will be updated accordingly.

(2) As per BC Hydro's "60 kV to 500 kV Technical Interconnection Requirements For Power Generators "(TIR) section 5.4.3, it is required that BC Hydro will conduct studies to determine the optimum PSS settings that will be implemented and confirmed by field tests during the commissioning of each generator.

5.12 Cost Estimate and Schedule

The detailed cost estimate for the Interconnection Network Upgrades and the estimated implementation schedule was produced in the previous Interconnection Facilities study report (TGI-2010-A080-FS-R1) is duplicated below.

"The cost estimate, +/- 20%, for the interconnection Network Upgrades required to interconnect the proposed project to the BCH Transmission System is $368,000. The estimated time to construct the Network Upgrades required to interconnect the project to the BCH Transmission System is 6 months."

The Interconnection Facilities Study report containing more detailed information of the cost estimates may need to be updated.

6.0 REVENUE METERING

Measurement Canada (MC) approved and sealed Revenue class meters will be installed at each of the IC's generating sites and at the POI. The main point of metering (POM) to be located at the POI should not be installed inside BC Hydro's station but outside the fence. The IC is responsible for securing the real estate for the main point of metering. The IC is also responsible for supplying auxiliary power and telecom for revenue metering use in each one of the points of metering. The location of the POMs is subject to approval by BC Hydro's Revenue Metering department.

The planning, design, installation and commissioning of the metering should be coordinated between the Interconnection Customer and BC Hydro's Revenue Metering Department. The responsibilities and charges between the Interconnection Customer and BC Hydro shall be in accordance with Section 10 (10.1 and 10.2) of BC Hydro's Requirements for Remotely Read Load Profile Revenue Metering.

All meters will be supplied and maintained by BC Hydro. Main and backup meters will use the same Current Transformers (CTs) and Voltage Transformers (VTs) secondaries and shall not share the secondary with any other equipment. The meter will be leased to the Interconnection Customer by BC Hydro. The Interconnection Customer will supply the MC approved CTs and VTs, a dedicated communications line for the POM, along with additional equipment. Please refer to Appendix E for more detailed information.

The estimated cost for network upgrades provided in this report do not include any costs for Revenue Metering.

7.0 CONCLUSIONS & DISCUSSION

In order to interconnect the subject project to the BCH Transmission System at the POI, this SIS has identified the following issues and requirements:

- No BCH transmission line or station upgrade is required for interconnecting the subject project.
- Addition of the subject project and other CPC projects will cause minor (1%) overload on ROS transformer T1 under normal condition. This overload will be mitigated by operator redispatch;
- Overload can occur on several BCH transformers and transmission lines after some single contingency outages. The existing Bridge River system generation shedding scheme will continue to be relied on to eliminate the overload. The subject project will be automatically included in the generation shedding scheme after entering service.
- The IC's units and other generating units in Bridge River area may lose stability after a 3-phase fault in the area. Generation shedding through the above mentioned Bridge River area scheme is needed in order to achieve acceptable dynamic performance. The IC is also required to provide out of step

protection at their site to trip the slipping units if adverse system conditions cause an unacceptable swing.

- Power quality type of anti-islanding protection is required to trip the IC's plants if an islanded condition does occur;
- The IC will provide a continuous (minimum 2400 bps) telecommunication channel from their sites to UHT station.

APPENDIX A – Power Flow Study Results

Base Case	Kwalsa Phase II Injection	Other Lower Mainland incld. Bridge River Gen. (MW)	Peace Generation (MW)	S.I. Generation (MW)	System Condition	3L5 UHT-ROS Loading (%)	ROS T1 Loading (%)	2L78 ROS-ALZ Loading (%)	3L2 UHT-BRT Loading (%)	BRT T4 Loading (%)	2L90 BRT-KLY Loading (%)	2L1, 5 BRT-RBW-CKY Loading (%)	2L2 BRT-RBW - CKY Loading (%)	2L9, 17 CKY-LYN-WLT Loading (%)	2L13 CKY-CYP Loading (%)	2L14 CYP-WLT Loading (%)	2L3 WLT-HPN Loading (%)	ROS 360kV Volt (pu)	BRT 360kV Volt (pu)
Equipment Summer Rating (MVA)						499	450	677	499	450	402	201	478/417	390	358	339	396		
2017 LS	MCR	MCR	550	784	Normal	77%	102%	65%	21%	87%	85%	45%	45%	86%	82%	63%	91%	1.016	1.019
2017 HS	MCR	MCR	550	4417	Normal	81%	103%	67%	23%	83%	66%	56%	51%	88%	87%	57%	95%	1.000	1.017
2017 HS	MCR	MCR	3750 (Full)	1313	Normal	85%	107%	69%	26%	79%	51%	66%	57%	95%	93%	63%	103%	0.997	1.017
Equipment Winter Rating (MVA)						499	501	797	499	534	512	352	478	475	465	439	478		
2016 HW	MCR	MCR	3750 (Full)	4327	Normal	85%	94%	58%	26%	68%	28%	45%	55%	70%	68%	37%	74%	99%	1.019

ii. Single-contingency Power Flow Results.

Base Case	Kwalsa Phase II Injection	Other LM Generation (MW)	Peace Generation (MW)	S.I. Generation (MW)	Conting-ency	3L5 Loading (%)	ROS T1 Loading (%)	2L78 Loading (%)	3L2 Loading (%)	BRT T4 Loading (%)	2L90* Loading (%)	2L1, 5 Loading (%)	2L2 Loading (%)	2L9, 17 Loading (%)	2L13 Loading (%)	2L14 Loading (%)	2L3 Loading (%)	ROS 360kV Volt (pu)	BRT 360kV Volt (pu)
2017 LS	MCR	MCR	550	784	BRT T4	165%	186%	129%	101%	/	37%	10%	21%	64%	62%	43%	16%	0.915	0.974
	MCR	MCR	550	784	ROS T1	14%	/	1%	74%	189%	146%	92%	76%	115%	109%	88%	127%	1.016	0.981
	MCR	MCR	550	784	3L5	/	16%	10%	60%	173%	136%	85%	71%	110%	104%	84%	121%	1.033	0.991
	MCR	MCR	550	784	3L2	59%	82%	52%	/	108%	97%	55%	51%	92%	88%	68%	98%	1.018	1.006
	MCR	MCR	550	784	2L90	104%	131%	85%	46%	57%	/	89%	74%	113%	107%	86%	123%	0.996	1.013
	MCR	MCR	550	784	2L1	79%	104%	66%	23%	85%	90%	/, 3%	54%	80%	77%	57%	83%	1.014	1.018
	MCR	MCR	550	784	2L5	80%	106%	67%	24%	83%	92%	12%, /	55%	81%	78%	58%	84%	1.014	1.019
	MCR	MCR	550	784	2L2	75%	101%	64%	20%	88%	82%	/	63%	67%	65%	46%	68%	1.017	1.020
	MCR	MCR	550	784	2L9	86%	112%	71%	29%	79%	104%	20%	29%	/, 4%	137%	115%	70%	1.021	1.021
	MCR	MCR	550	784	2L17	86%	111%	71%	29%	77%	103%	21%	30%	4%, /	134%	113%	70%	1.010	1.016
	MCR	MCR	550	784	2L13	84%	110%	70%	27%	79%	100%	25%	33%	133%	/	17%	76%	1.011	1.017
	MCR	MCR	550	784	2L14	80%	106%	67%	24%	83%	92%	35%	39%	109%	43%	/	82%	1.014	1.018
2017HS	MCR	MCR	3750 (Full)	1313	BRT T4	168%	181%	130%	102%	/	7%	32%	36%	74%	74%	45%	77%	0.896	0.995
	MCR	MCR	3750 (Full)	1313	ROS T1	12%	/	0%	70%	187%	115%	109%	85%	123%	117%	90%	141%	1.038	1.013
	MCR	MCR	3750 (Full)	1313	2L90	102%	124%	82%	42%	61%	/	93%	75%	111%	108%	78%	123%	0.982	1.010
	MCR	MCR	3750 (Full)	1313	2L9	95%	118%	77%	36%	68%	72%	38%	40%	/, 9%	153%	121%	80%	0.987	1.013
2017LS	MCR	ELCC	550	784	BRT T4	125%	152%	99%	96%	/	25%	10%	15%	48%	48%	30%	46%	0.981	1.007
	MCR	ELCC	550	784	ROS T1	16%	/	0%	55%	155%	111%	72%	58%	89%	85%	65%	95%	1.030	1.008
	MCR	ELCC	550	784	2L90	77%	102%	65%	48%	53%	/	71%	58%	88%	84%	65%	93%	1.019	1.012
	MCR	ELCC	550	784	2L9	63%	87%	55%	35%	68%	81%	17%	23%	/, 4%	109%	88%	54%	1.021	1.021
	MCR	ELCC	550	784	2L13	61%	85%	54%	32%	70%	78%	21%	26%	105%	101%	17%	58%	1.021	1.022
2017HS	MCR	ELCC	550	784	BRT T4	128%	149%	101%	96%	/	7%	18%	22%	51%	53%	24%	50%	0.951	0.997
	MCR	ELCC	550	784	ROS T1	12%	/	0%	41%	153%	92%	83%	65%	91%	89%	59%	100%	1.036	1.009
	MCR	ELCC	550	784	2L90	75%	96%	62%	45%	55%	/	72%	57%	84%	83%	83%	90%	1.004	1.019
	MCR	ELCC	550	784	2L9	67%	89%	57%	37%	64%	61%	29%	29%	/	113%	82%	55%	1.008	1.021
	MCR	ELCC	550	784	2L13	66%	87%	56%	38%	65%	59%	32%	31%	109%	/	30%	62%	1.008	1.022
2016HW	MCR	ELCC	3750 (Full)	4327	BRT T4	130%	132%	86%	96%	/	20%	27%	34%	40%	43%	25%	40%	0.938	1.002
	MCR	ELCC	3750 (Full)	4327	ROS T1	14%	/	0%	41%	128%	49%	61%	70%	73%	70%	39%	77%	1.006	1.027
2017LS	MCR	ELCC-250MW at BR1 & BR2	550	784	BRT T4	74%	99%	63%	45%	/	24%	9%	15%	49%	48%	29%	47%	1.019	1.029
	MCR		550	784	ROS T1	16%	/	1%	43%	100%	78%	47%	43%	74%	72%	52%	78%	1.039	1.024

APPENDIX B – Transient Stability Simulation Results

i. Transient simulation results -- without Generation Shedding.

	Outage	3Φ Fault Location	Generator Maximum Rotor Angle Swing (degree)														Min Transient Volt. (pu)		Perfor-mance Accept-able?
			BR1	BR2	WAH	BSV	TWY	NWS	BRE	TRE	TPA	USR	LMN	FRE	DGL	SKK	BRT 360	ROS 360	
1	3L5	UHT 360	Unstable	Unstable	≤40	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	<0.7	>0.95	No
2	3L5	ROS 360	Unstable	Unstable	40	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	<0.7	>0.95	No
3	3L2	UHT 360	≤40	≤40	≤40	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	>0.95	<0.7	No
4	3L2	BRT 360	70	70	20	≤80	≤80	≤80	≤80	≤80	≤60	≤60	≤60	≤60	≤60	≤60	>0.75	>0.8	Yes
5	BRT T4 (360/230)+ 2L19+BR1 T3(230/66/12)	BRT 360	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	<0.7	<0.7	No
6	Same as 5	BRT 230	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	<0.7	<0.7	No
7	Same as 5	BR1 66	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	<0.7	<0.7	No
8	ROS T1 (360/230)+2L78	ROS 360	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	<0.7	<0.7	No
9	ROS T1 (360/230)+2L78	ALZ 230	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	<0.7	<0.7	No
10	2L77 + CBN T7(230/60) +CBN T3 (230/25)	CBN 230	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	Unstable	<0.7	<0.7	No
11	Same as 10	CBN 60	≤40	≤40	≤80	≤60	≤60	≤60	≤60	≤60	≤60	≤60	≤60	≤60	≤60	≤60	>0.85	>0.9	Yes
12	Same as 10	CBN 25	≤40	≤40	≤60	≤40	≤40	≤40	≤40	≤40	≤40	≤40	≤40	≤40	≤40	≤40	>0.9	>0.9	Yes
13	2L90 BRT-KLY	BRT 230	≤80	≤80	<40	≤60	≤60	≤60	≤60	≤60	≤60	≤60	≤60	≤60	≤60	≤60	>0.75	>0.75	Yes
14	2L90 BRT-KLY	KLY 230	≤60	≤60	≤40	≤40	≤40	≤40	≤40	≤40	≤40	≤40	≤40	≤40	≤40	≤40	>0.85	>0.85	Yes
15	2L1 BRT-FCN	BRT 230	≤60	≤60	≤40	≤40	≤40	≤40	≤40	≤40	≤40	≤40	≤40	≤40	≤40	≤40	>0.8	>0.85	Yes
16	2L2 BRT-CKY	BRT 230	≤60	≤60	≤40	≤40	≤40	≤40	≤40	≤40	≤40	≤40	≤40	≤40	≤40	≤40	>0.85	>0.85	Yes

ii. Transient simulation results -- with Generation Shedding.

	Outage	3Φ Fault Location	BR1	BR2	WAH	BSV	TWY	NWS	BRE	TRE	TPA	USR	LMN	FRE	DGL	SKK	BRT 360	ROS 360	Performance Acceptable?
1	3L5	UHT	≤60	≤60	≤40	Shed	Shed	Shed	≤90	≤90	Shed	Shed	Shed	Shed	Shed	Shed	>0.8	>0.95	Yes
2	3L5	ROS 360	≤40	≤40	≤40	Shed	Shed	Shed	<80	<80	Shed	Shed	Shed	Shed	Shed	Shed	>0.85	>0.95	Yes
3	3L2	UHT 360	≤40	≤40	≤40	Shed	Shed	Shed	<80	<80	Shed	Shed	Shed	Shed	Shed	Shed	>0.9	>0.9	Yes
7	Same as 5	BR1 66	≤40	≤40	≤40	Shed	Shed	Shed	≤40	≤40	Shed	Shed	Shed	Shed	Shed	Shed	>0.85	>0.85	Yes
8	ROS T1 (360/230)+2L87	ROS 360	≤60	≤60	≤80	Shed	Shed	Shed	<80	<80	Shed	Shed	Shed	Shed	Shed	Shed	>0.85	>0.85	Yes
9	ROS T1 (360/230)+2L87	ALZ 230	≤60	≤60	≤80	Shed	Shed	Shed	<80	<80	Shed	Shed	Shed	Shed	Shed	Shed	>0.85	>0.85	Yes
10	2L77 + CBN T7(230/60) +CBN T3 (230/25)	CBN 230	≤60	≤60	≤80	Shed	Shed	Shed	<80	<80	Shed	Shed	Shed	Shed	Shed	Shed	>0.85	>0.85	Yes
5	BRT T4 (360/230)+ 2L19+BR1 T3(230/66/12)	BRT 360	Shed	Shed	≤60	Shed	Shed	Shed	Shed	Shed	Shed	Shed	Shed	Shed	Shed	Shed	>1	>1	Yes
6	Same as 5	BRT 230	Shed	Shed	≤60	Shed	Shed	Shed	Shed	Shed	Shed	Shed	Shed	Shed	Shed	Shed	>1	>1	Yes

* The generation shedding arrangements shown in the table are tentative. More accurate shedding requirements will be determined in future operation studies.

APPENDIX C – Dynamics Data

Big Silver Creek (BSV)

BSV Unit Rating: G1 6.816 MVA; G2-G4 13.56 MVA. All are 0.9/0.9 leading/lagging power factors, 6.9kV.

Generator: GENSAL

	T'_{D0}	T''_{D0}	T''_{Q0}	H	D	X_D	X_Q	X'_D	X''_D	X_L	S(1.0)	S(1.2)
BSV G1	2.47	0.0338	0.0812	0.8169	0	1.49	0.894	0.267	0.171	0.0786	0.086	0.394
BSV G2-G4	3.01	0.0471	0.089	1.1983	0	1.495	0.897	0.342	0.213	0.1059	0.076	0.372

Exciter: AC8B

	T_R	K_{PR}	K_{IR}	K_{DR}	T_{DR}	K_{PIDMX}	K_{PIDMN}	K_A	T_A	V_{RMAX}	V_{RMIN}	K_C	K_D	K_E	T_E	V_{EFM}	V_{EFN}	E_1	S_{E1}	E_2	S_{E2}
BSV G1	0.01	80	20	10	0.01	99	-99	1.0	0.01	6.45	0	0	0	1	0.139	99	0	4.22	0.023	5.63	0.145
BSV G2-G4	0.01	80	20	10	0.01	99	-99	1.0	0.01	6.58	0	0	0	1	0.134	99	0	4.25	0.081	5.67	0.160

Power System Stabilizer (PSS): PSS2A for BSV G1-G4

IC1	REMBUS1	IC2	REMBUS2	M	N			
1	0	3	0	5	1			
T_{W1}	T_{W2}	T_6	T_{W3}	T_{W4}	T_7	K_{S2}	K_{S3}	
7	7	0	7	0	7	3.18*	1	
T_8	T_9	K_{S1}	T_1	T_2	T_3	T_4	V_{STMAX}	V_{STMIN}
0.5	0.1	7	0.07	0.02	0.07	0.02	0.05	-0.05

* KS2=4.81 for BSV G1.

Governor: WSHYDD for BSV G1-G4

db1	err	T_d	K_1	T_f	K_D	K_P	R
0	0	0.01	4	0.4	5	0.2	0.05
T_t	K_G	T_P	VEL_{OPEN}	VEL_{CLOSE}	P_{MAX}	P_{MIN}	db_2
0	1	0.4	0.02	0.02	1	0	0
GV_1	P_{GV1}	GV2	P_{GV2}	GV3	P_{GV3}	GV4	P_{GV4}
0	0	0.15	0	0.7	0.8	0.8	0.9
GV5	P_{GV5}	A_{turb}	B_{turb}	T_{turb}	T_{rate}		
1	1	-1	0.5	1.5	12.5**		

**T_{rate}=6.3 for BSV G1.

Tretheway Creek (TWY)

TWY Unit Ratings (G1-G2): 12.973 MVA, 0.90 power factor, 6.9 kV.

Generator: GENSAL

Unit	T'_{D0}	T''_{D0}	T''_{Q0}	H	D	X_D	X_Q	X'_D	X''_D	X_L	S(1.0)	S(1.2)
TWY G1-G2	2.6	0.042	0.073	1.01	0.0	1.5	0.9	0.37	0.24	0.095	0.082	0.55

Exciter Model: AC8B

	T_R	K_{PR}	K_{IR}	K_{DR}	T_{DR}	K_{PIDMX}	K_{PIDMN}	K_A	T_A	V_{RMAX}	V_{RMIN}	K_C	K_D	K_E	T_E	V_{EFM}	V_{EFN}	E_1	S_{E1}	E_2	S_{E2}
TWY G1-G2	0.01	80	20	10	0.01	99	-99	1.0	0.01	11.1	0.0	0	0	1.0	0.128	99	0	2.31	0.64	4.621	0.79

Note: The PID controller output limits are assumed to be fully open, i.e. K_{PIDMAX} = 99 and K_{PIDMIN} = -99 in PSS/E type AC8B exciter model.

Power System Stabilizer Data (PSS2A):

Unit	IC1	IC2	M	N	T_{w1}	T_{w2}	T_6	T_{w3}	T_{w4}	T_7	K_{s2}	K_{s3}	T_8	T_9	K_{s1}	T_1	T_2	T_3	T_4	V_{smx}	V_{smn}
G1	1 0	3 0	5	1	7	7	0	7	0	7	3.47	1.0	0.5	0.1	7.0	0.07	0.02	0.07	0.02	0.05	-0.05
G2	1 0	3 0	5	1	7	7	0	7	0	7	3.47	1.0	0.5	0.1	7.0	0.07	0.02	0.07	0.02	0.05	-0.05

Note: Ks2 should be set to T7/(2H) all the time.

Governor: WSHYDD for TWY G1-G2

db1	err	T_d	K_1	T_f	K_D	K_P	R
0	0	0.01	4	0.4	5	0.2	0.05
T_t	**K_G**	**T_P**	**VEL_{OPEN}**	**VEL_{CLOSE}**	**P_{MAX}**	**P_{MIN}**	**db_2**
0	1	0.4	0.02	0.02	1	0	0
GV_1	**P_{GV1}**	**GV2**	**P_{GV2}**	**GV3**	**P_{GV3}**	**GV4**	**P_{GV4}**
0	0	0.15	0	0.7	0.8	0.8	0.9
GV5	**P_{GV5}**	**A_{turb}**	**B_{turb}**	**T_{turb}**	**T_{rate}**		
1	1	-1	0.5	1.5	11.67		

Note: Actual turbine rating data should be used for the last parameter of the governor model.

Northwest Stave River (NWS)

NWS Unit Rating: G1-G2 9.035 MVA, G3 3.427 MVA. All are 0.9 lagging power factor, 6.9 kV.

Generator: GENSAL

Unit	T'_{D0}	T''_{D0}	T''_{Q0}	H	D	X_D	X_Q	X'_D	X''_D	X_L	S(1.0)	S(1.2)
NWS G1-G2	1.97	0.034	0.057	1.19	0.0	1.19	0.773	0.327	0.224	0.109	0.088	0.22
NWS G3	1.80	0.019	0.041	0.6644	0.02	1.512	0.907	0.313	0.207	0.106	0.115	0.446

Exciter Model: AC8B

Unit	T_R	K_{PR}	K_{IR}	K_{DR}	T_{DR}	K_{PIDMX}	K_{PIDMN}	K_A	T_A	V_{RMAX}	V_{RMIN}	K_C	K_D	K_E	T_E	V_{EFM}	V_{EFN}	E_1	S_{E1}	E_2	S_{E2}
NWS G1-G2	0.01	80	20	10	0.01	99.0	-99.0	1.0	0.01	9.36	0.0	0	0	1.0	0.128	99.0	0.0	3.80	0.086	5.10	0.286
NWSG3	0.01	80	20	10	0.01	99.0	-99.0	1.0	0.01	9.36	0.0	0	0	1.0	0.128	99.0	0.0	3.55	0.01	4.733	0.03

Notes:

1. The PID controller output limits are assumed to be fully open, i.e. K_{PIDMAX} = 99.0 and K_{PIDMIN} = -99.0 in PSS/E type AC8B exciter model.
2. The exciter saturation factors for unit 3 are recalculated based on the exciter saturation curve provided. The exciter saturation factors for units 1 and 2 are corrected by switching S_{E1} and S_{E2}.

Power System Stabilizer Data: PSS2A for NWS G1-G3

Unit	IC1	IC2	M	N	T_{w1}	T_{w2}	T_6	T_{w3}	T_{w4}	T_7	K_{s2}	K_{s3}	T_8	T_9	K_{s1}	T_1	T_2	T_3	T_4	V_{smx}	V_{smn}
G1-G2	1 0	3 0	5	1	7	7	0	7	0	7	2.94	1.0	0.5	0.1	7.0	0.07	0.02	0.07	0.02	0.05	-0.05
G3	1 0	3 0	5	1	7	7	0	7	0	7	5.27	1.0	0.5	0.1	7.0	0.07	0.02	0.07	0.02	0.05	-0.05

Notes: Ks2 should be set to T7/(2H) all the time.

Governor: WSHYDD for NWS G1-G3

db1	**err**	**T_d**	**K_1**	**T_f**	**K_D**	**K_P**	**R**
0	0	0.01	4	0.4	5	0.2	0.05
T_t	**K_G**	**T_P**	**VEL_{OPEN}**	**VEL_{CLOSE}**	**P_{MAX}**	**P_{MIN}**	**db_2**
0	1	0.4	0.02	0.02	1	0	0
GV_1	**P_{GV1}**	**GV2**	**P_{GV2}**	**GV3**	**P_{GV3}**	**GV4**	**P_{GV4}**
0	0	0.15	0	0.7	0.8	0.8	0.9
GV5	**P_{GV5}**	**A_{turb}**	**B_{turb}**	**T_{turb}**	**T_{rate}**		
1	1	-1	0.5	1.5	8.13**		

**Trate=3.08 for NWS G3.

Notes: Actual turbine rating data should be used for the last parameter of the governor model.

APPENDIX D - Post Disturbance Swings of the Interconnected Systems

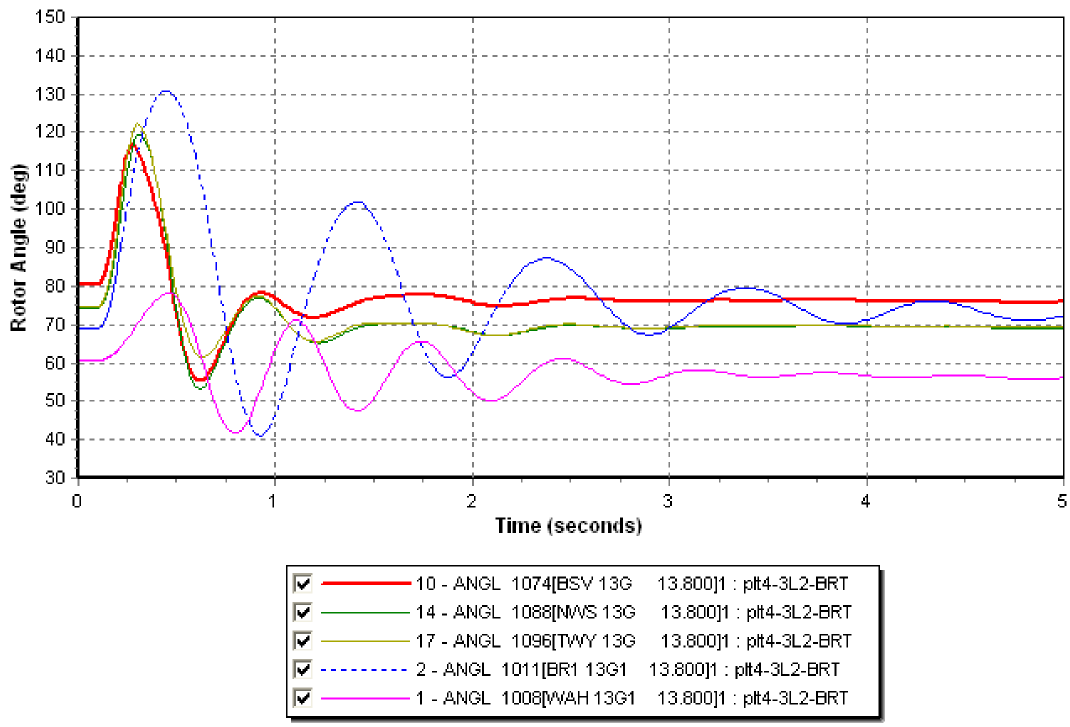

Figure D1. Rotor angle swing curves for a three-phase fault on 3L2 at BRT (Case4 in Appendix B)

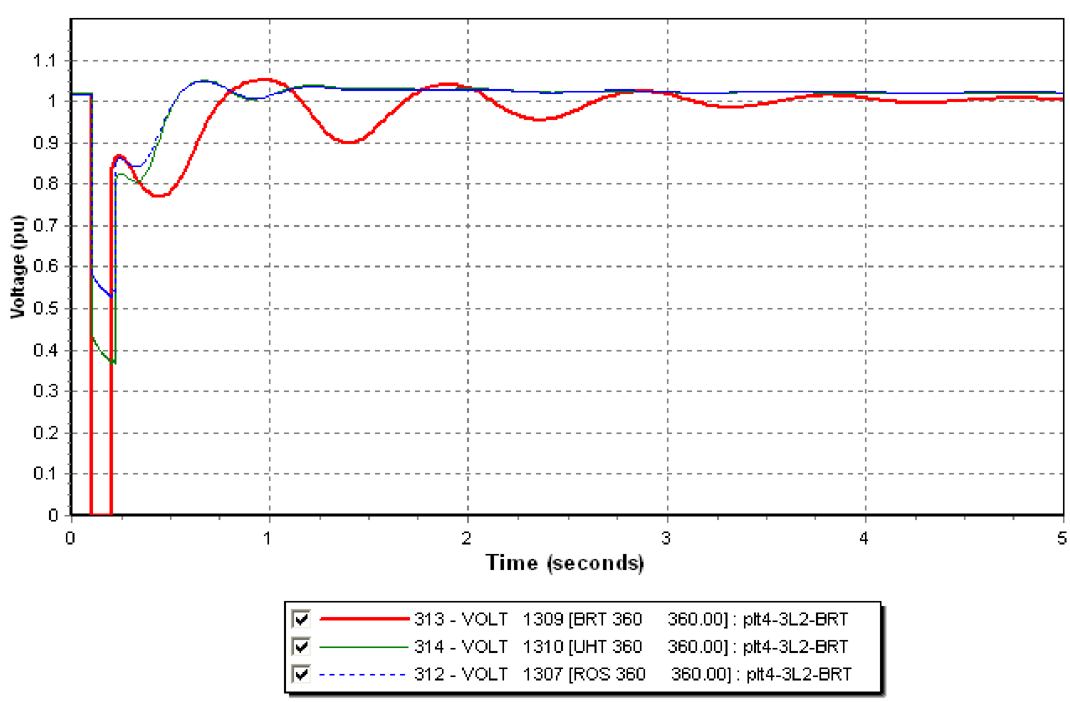

Figure D2. Voltage swing curves for a three-phase fault on 3L2 at BRT (Case4 in Appendix B)

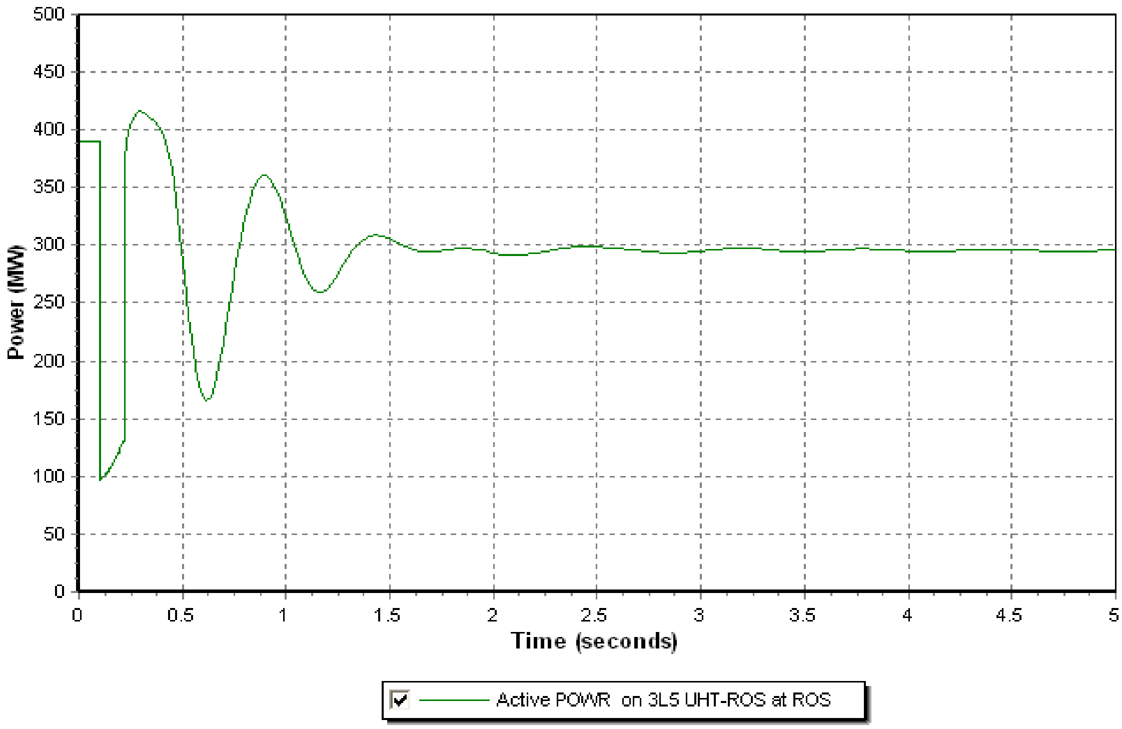

Figure D3. Power swing curves for a three-phase fault on 3L2 at BRT (Case4 in Appendix B)

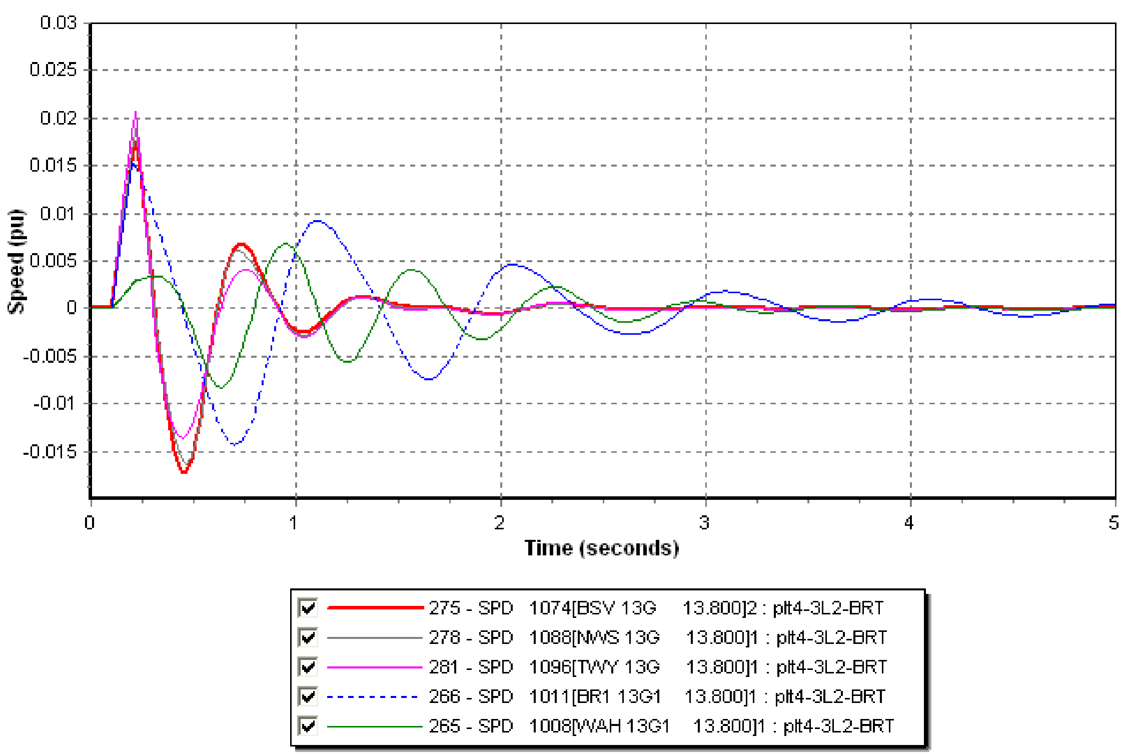

Figure D4. Frequency swing curves for a three-phase fault on 3L2 at BRT (Case4 in Appendix B)

APPENDIX E – Revenue Metering

Revenue class meters approved and sealed by Measurement Canada (MC) shall be installed on the output of the generator. As per federal regulations, the meter should be periodically removed and re-verified in a MC authorized laboratory. The CTs and VTs used on the metering scheme shall also be of a model/type approved by Measurement Canada. The location of the Point-of-Metering (POM) is subject~~ed~~ to approval by BC Hydro's Revenue Metering department. The planning, design, installation and commissioning of the point of metering should be coordinated between the power generator and BC Hydro's Revenue Metering Department. The responsibilities and charges between the Interconnection Customer and BC Hydro shall be in accordance with Section 10 (10.1 and 10.2) of BC Hydro's Requirements for Remotely Read Load Profile Revenue Metering. For a complete list of tasks, see table on pages 23-25:

http://www.bchydro.com/etc/medialib/internet/documents/appcontent/your_account/requirements_for_remotely_read_load_profile_revenue_metering.Par.0001.File.requirements_for_remotely_read_load_profile_metering_jun2004.pdf

All meters will be supplied and maintained by BC Hydro. Main and backup meters will use the same CTs and VTs secondaries and shall not share the secondary with any other equipment. The meter will be leased to the Interconnection Customer by BC Hydro. The revenue class instrument transformers (CTs and VTs units) will be supplied by the Interconnection Customer and must be a MC approved model. A list of approved models is available at the MC website under "Notice of Approval Database Section". The remote read load profile revenue metering equipment should be in accordance with BC Hydro Requirements for Remotely Read Load Profile Revenue Metering. The latest version of this document is published at BC Hydro webpage under Forms and Guides.

Main and backup bi-directional load profile interval meters are required to measure the power received and the power delivered by BC Hydro (BCH) during each 30 minute time period. The meters will be programmed for 5 minute intervals and will be remotely read each day by the BCH Enhanced Billing Group using MV-90 software. The POM requires a dedicated communications line that is provided by the Customer. This line should be available on the meter cabinet and it is for revenue metering use only. The communication line provided could be a protected landline or a wireless alternative approved by BC Hydro. The landline should be installed in accordance with *"IEEE Standard 487 Guide for the Protection of Wire-Line Communication Facilities Serving Electric Power Stations".* If there is digital cellular phone coverage for data (IP), due to IT security reasons, BC Hydro will supply the wireless communications equipment at an incremental cost to the Interconnection Customer.

A *3*--element metering scheme with 3 CTs and 3 VTs connected L-N (Grd) will be used when the POM is located on the BC Hydro side of the power transformer. If the POM is located on the low side of the power transformer (Power Generator side of the power transformer) and the Power Generator (PG) installation is a three phase, three wire, delta connection, or a three phase, four wire, WYE with a **resistance or impedance grounded neutral** (treated as a DELTA connection), a *2*-element metering scheme with 2 CTs and 2 VTs connected L-L will be used instead.

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

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 Interconnection Customer shall provide the line parameters data and the power transformer testing report data signed and stamped by a professional engineer.

Where two or more Interconnection Customers or one Interconnection Customer with more than one generating station/generator share a private power line to connect to the BCH system, a main POM located in the Point-of-Interconnection (POI) will be required, as well as an individual POM on each one of the generating stations/generators.

During the planning phase, BC Hydro's Revenue Metering Department should be contacted to discuss costs and specifics of the project. The Interconnection Customer should prepare and submit drawings showing the single line diagram (SLD), station lay-out and informing the proposed metering scheme, the length of the secondary cables needed (between CT/VT and the meter cabinet), meter cabinet location, CTs and VTs location, model/maker, connections, and MC Approval numbers, as well as any other related documentation.

Information required in the design stage includes:

1. Length of secondary cables
2. CT and VT models and approvals from Measurement Canada and if they come with a second set of secondaries
3. Single Line Diagram showing CTs, VTs, cabinets, all generating stations connecting to the POI
4. Identify whether revenue metering cabinets are indoors or outdoors - implication on whether cabinets need to be insulated
5. Communication medium contemplated to relay revenue metering data
6. 3-line diagram of the interconnection of the revenue metering CT & VT
7. Scaled Site Plan showing the relative location of the meter cabinet to the CT & VT (drawing showing the footprint for the sub)
8. Private power line parameters data and/or the power transformer testing data signed and stamped by a professional engineer
9. A set of manufacture switchgear drawings showing the installation of the revenue metering CT & VT (ensure the installation of the metering CT & VT complies with section 5.4 of BCH Requirements for Remotely Read Load Profile Revenue Metering, published at BCH website)
10. A simplified version of the lockout access steps to the revenue metering CT & VT (if already available)
11. Verification of dedicated 120V AC 15A circuit for the meter cabinet - as per section 6.4 of BCH requirements
12. Contact name/phone on site for equipment/material delivery.
13. Royal Mailing Address for the site (normal mailing address)
14. Interconnection Customer Billing Information
15. A copy of Measurement Canada issued Certificate of Registration for the Interconnection Customer
16. Operational Site Access for BC Hydro Meter Tech (for metering installation, maintenance, etc.)

The BC Hydro's Revenue Metering department can be contacted at: metering.revenue@bchydro.com.