[redacted]

Narrows Inlet Project
Interconnection System Impact Study

Report #: T&S Planning 2016-010

March 2016

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

Disclaimer of Warranty and Limitation of Liability

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

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

Unless otherwise expressly agreed by BCH:

1. any assumption, data or information (whether embodied in tangible or electronic form) supplied by, or gathered from, any source (including, without limitation, any consultant, contractor or subcontractor, testing laboratory and equipment suppliers, etc.) upon which BCH's opinion or conclusion as set out in this report is based (individually and collectively, "Information") has not been verified by BCH or BCH's Personnel; BCH makes no representation as to its accuracy or completeness and disclaims all liability with respect to the Information;
2. except as expressly set out in this report, all terms, conditions, warranties, representations and statements (whether express, implied, written, oral, collateral, statutory or otherwise) are excluded to the maximum extent permitted by law and, to the extent they cannot be excluded, BCH disclaims all liability in relation to them to the maximum extent permitted by law;
3. BCH does not represent or warrant the accuracy, completeness, merchantability, fitness for purpose or usefulness of this report, or any information contained in this report, for use or consideration by any person or entity. In addition BCH does not accept any liability arising out of reliance by a person or entity on this report, or any information contained in this report, or for any errors or omissions in this report. Any use, reliance or publication by any person or entity of this report or any part of it is at their own risk; and
4. In no event will BCH or BCH's Personnel be liable to any recipient of this report for any damage, loss, cost, expense, injury or other liability that arises out of or in connection with this report including, without limitation, any indirect, special, incidental, punitive or consequential loss, liability or damage of any kind.

Copyright Notice

Executive Summary

[redacted] the Interconnection Customer (IC), proposes to develop the Narrows Inlet Project to deliver electric energy to BC Hydro (BCH). The project, located in the Sunshine Coast region, consists of four generating stations with a total five generators: Chickwat with two generators each 9.5 MW, Tyson Creek (about) 10 MW, Upper Ramona Creek 7.0 MW, and Lower Ramona Creek 7.0 MW. The IC will build a customer owned 26 km, 132 kV transmission line from their 132/25 kV collector station Narrows Inlet (NITX) and tap into BCH 132 kV circuit 1L37 at the Point of Interconnection (POI), approximately 5 km north from Malaspina Substation (MSA). The maximum power injection into the BCH system is 40 MW, and the proposed Commercial Operation Date (COD) is November 1, 2017.

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 Narrows Inlet Project and its facilities to the BCH Transmission System through a tap point on 132 kV line 1L37, this System Impact Study (SIS) has identified the following conclusions and requirements:

(1) A "T" connection on line 1L37 with three 138 kV disconnects will be created at the POI.

(2) A direct transfer trip (DTT) scheme will be required to disconnect Narrows Inlet generation for MSA T1 or T5 outages.

(3) To prevent overvoltages the no-fault opening of 1L37 at MSA will be delayed so that Narrows Inlet will be tripped before 1L37 opens.

(4) The 1L37 line protection will be replaced by new relays. The IC is responsible to provide line protection at their NITX station for their 132 kV tap line to the POI.

(5) An ADSS fibre optic line will be needed from NITX to MSA station via the POI. BCH will supply, install, and terminate the fibre optic portion between MSA and the POI. The IC will supply, install, and terminate the fibre optic portion between NITX and the POI.

(6) Out-of-step protection will be required at the IC's generators, provided by the IC.

(7) Islanded operation will not be arranged. Power quality protection will be required to prevent/mitigate possible inadvertent islanded operation.

(8) During outages of BCH's 230 kV line 2L48 MSA to Saltery Bay (SAY) the line 1L37 MSA-SAY will be operated closed to provide the backup supply. In this operating condition the Narrows Inlet generators will need to be disconnected from the BCH system.

(9) Associated with the interconnection project there will be BCH protection, control, and telecommunication work in the related transmission lines, substations, and control centers.

(10) The project will change the 25 kV POI for the existing generator at Tyson Creek (TYS) to the Narrows Inlet Project's POI. BCH will need to do removals and changes at the location of the present POI on Pender Harbour (PHR) feeder 25F53.

(11) The non-binding good-faith cost estimate for Interconnection Network Upgrades required to interconnect the proposed project to BCH Transmission System is $3.92 million, and the estimated time to complete the Interconnection Network Upgrades is 18 months after project approval. The work required within the IC facilities or the Revenue Metering facilities is not part of Interconnection Network Upgrades. The BCH work to do removals and changes at the existing 25 kV POI for TYS is also not included in the cost estimate of the Network Upgrades.

The Interconnection Facilities Study report will provide greater details of the Interconnection Network Upgrade requirements and associated cost estimate and estimated construction timeline for this project.

Table of Contents

List of Tables

List of Figures

1. Introduction

The proposed Narrows Inlet Project is a modified version of an earlier proposed project "Stlixwim" which was the subject of an Interconnection System Impact Study report and a Facilities Study Report, both dated 2010.

In August 2015 the Interconnection Customer (IC), [redacted] proposed a revised project "Narrows Inlet" with modified generator data and a maximum power injection of 40 MW into the BCH Transmission System. The Narrows Inlet project has a total installed capacity about 12 MW less than that of the earlier Stlixwim proposal.

The project reviewed in this system impact study is described in Table 1-1 below.

Table 1-1: Summary of Project Information

Project Name	Narrows Inlet Project	
Interconnection Customer	[redacted]	
Point of Interconnection	A tap onto 132 kV line 1L37, 5 km from MSA	
IC Proposed COD	November 1, 2017	
Type of Interconnection Service	NRIS ☒	ERIS ☐
Maximum Power Injection (MW)	40.0 (Summer)	40.0 (Winter)
Number of Generator Units	5	
Plant Fuel	Hydro	

The IC proposes to connect this project via their own 26 km line onto a POI located about 5 km from Malaspina (MSA) on the 132 kV line 1L37 MSA to Saltery Bay (SAY). Maximum injection at the POI from this project is 40.0 MW.

The IC's generation and transmission system facilities include:

- Two 10.55 MVA generators at Chickwat (CKW);
- One 7.77 MVA generator at Lower Ramona (RML);
- One 7.77 MVA generator at Upper Ramona (RMU);
- One 10.33 MVA generator at Tyson Creek (TYS);
- The collector station NITX with a 132/25 kV transformer rated 83 MVA;
- Several 25 kV lines (of lengths 4 to 7 km) connecting the generating sites to NITX;
- A 26 km 132 kV line (overhead construction except for a 1.6 km submarine section) between NITX and the POI.

The generating station Tyson Creek (TYS) is an existing facility which is connected at 25 kV to BCH's 132/25 kV distribution substation Pender Harbour (PHR). The IC's proposed project will change the configuration so that the TYS generation will be connected to their 132/25 kV collector station NITX.

The proposed Commercial Operation Date is November 1, 2017.

The geographical locations of the facilities in the area, including the IC, are shown in Figure 1-1 and a transmission system diagram is shown in Figure 1-2.

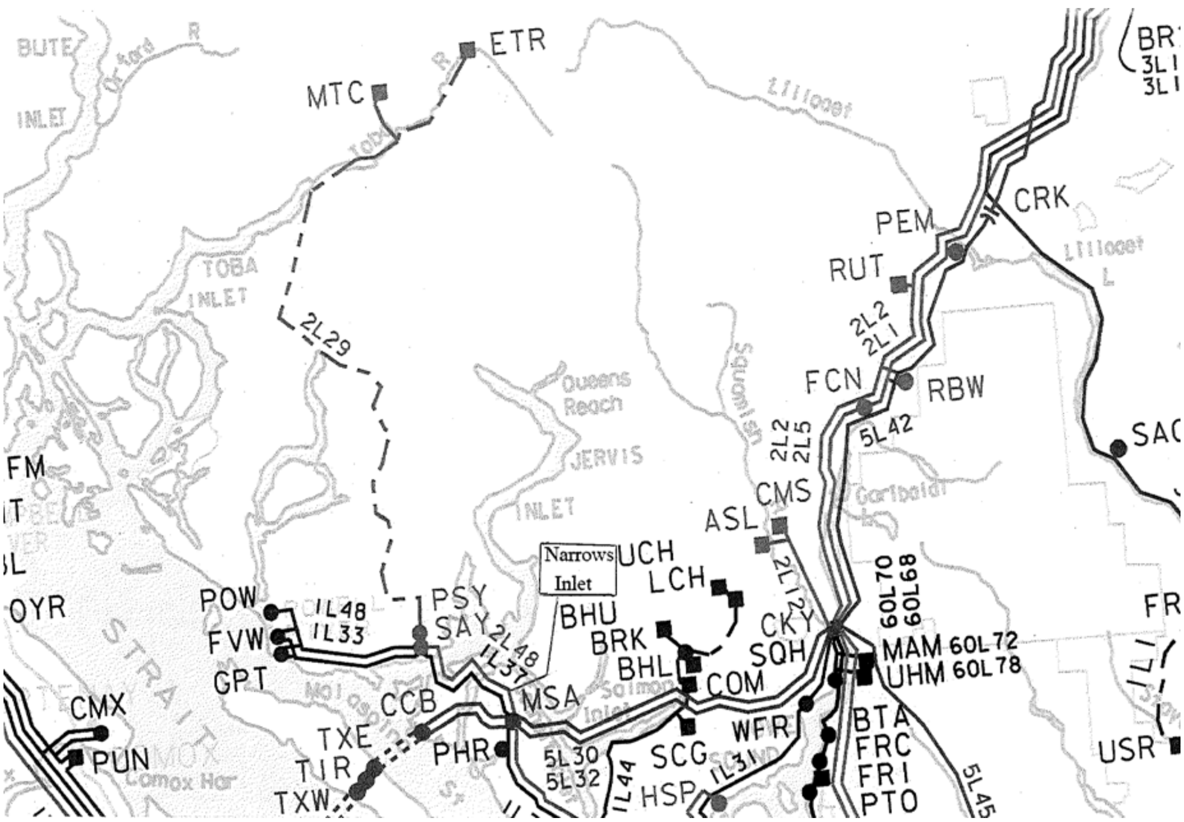


Figure 1-1: Interconnection Geographical Location Diagram

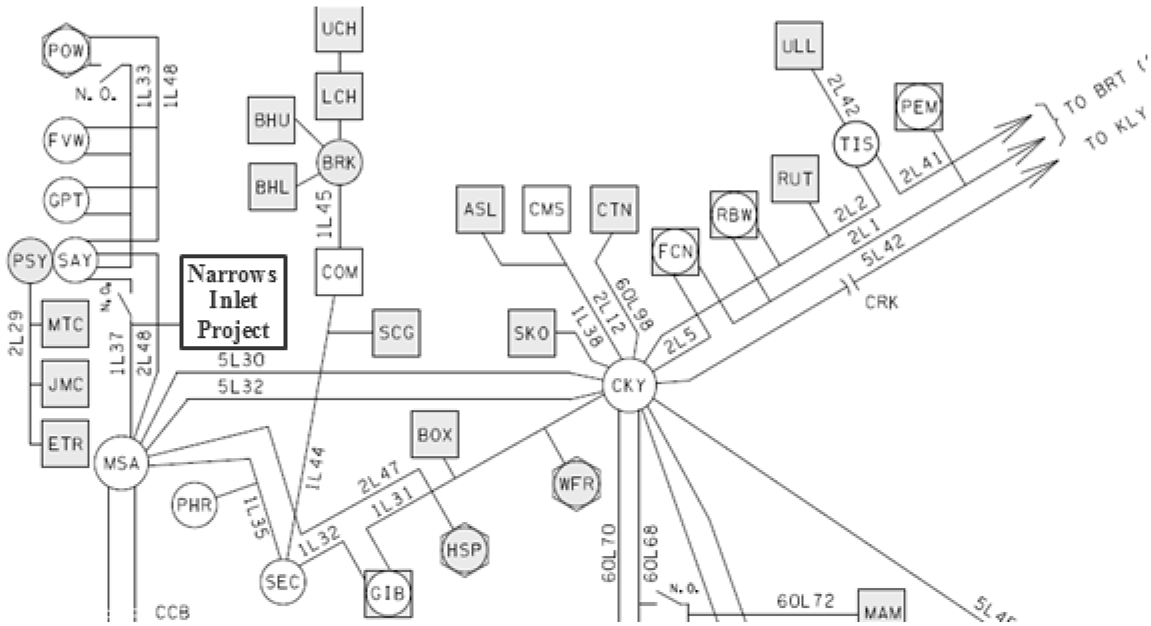


Figure 1-2: Transmission System Diagram

2. Study Purpose

The purpose of this SIS is to assess the impact of the interconnection of the proposed project on the BCH Transmission System. This study shall identify constraints and Network Upgrades required for interconnecting the proposed generating project in compliance with the NERC/WECC reliability standards and the BCH transmission planning criteria.

3. Terms of Reference

This study investigates and addresses the overloading, voltage deviation, and stability issues of the transmission network in the Sunshine Coast region as a result of the proposed interconnection for system normal and single contingency conditions. The studied topics include equipment thermal loading and rating requirements, system transient stability and voltage stability, transient over-voltages, potential harmonic resonances, 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 network studies will determine the requirements for reinforcements or operating restrictions/instructions for those types of events.

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

4. Assumptions

The studied power flow conditions are to include generation, transmission facilities, and load forecasts representing the BCH interconnection queue position applicable to this project. Applicable seasonal conditions and the appropriate study years for the study horizon are also to be incorporated. As a result, BCH 2017/18 Heavy Winter, 2018 Heavy Summer, and 2018 Light Summer power flow base cases were selected for this study. The IC's latest data submission in 2015 September has been used in this study.

All projects ahead of Narrows Inlet project in the Interconnection Queue are included in the study model. Powell River (POW) substation, supplied by 132 kV transmission lines from the SAY 230/132 kV station, currently serves a transmission customer who has its own generation. In this study, the studied scenario is based on 0 MW of generation injection from POW to the BCH system;

In addition to the proposed Narrows Inlet Project's generation and transmission system facilities, 13 other transmission-connected and distribution-connected generation facilities were also included in the region, and which were represented in the base cases at their Maximum Continuous Rating (MCR) levels, as summarized in Table 4-1 below.

Generation in the Sunshine Coast area used in the study are shown in the following table.

Table 4-1: Summary of MCR for the other Generators in the region

Project Name	Abbre-vation	Generator Type		Maximum Continuous Rating (MCR) (MW)
East Toba River generation	ETR	Hydro, existing IPP		146
Montrose Creek generation	MTC	Hydro, existing IPP		88
Jimmie Creek Hydro	JMC	Hydro, existing IPP		61
McNair Creek Hydro	MCH	Hydro, existing IPP		8.91
Box Canyon Hydro	BOX	Hydro, existing IPP		15.9
Woodfibre IPP	WFR	Hydro, existing IPP		1.6
Skookum Creek Project	SKO	Hydro, existing IPP		27.5
Sechelt Creek	SCG	Hydro, existing IPP		16.6
Upper Clowhom	UCH	Hydro, existing IPP		11
Lower Clowhom	LCH	Hydro, existing IPP		11
Clowhom Generating Station	COM	Hydro, existing IPP		31
Lower Bear Hydro Project	BHL	Hydro, existing IPP		8
Upper Bear Hydro Project	BHU	Hydro, existing IPP		12
Total	--	--		438.51

A “T” connection on circuit 1L37 with three 132 kV line disconnects will be created at the POI.

BCH’s present operating procedures in the SAY to MSA 230 kV and 132 kV transmission system will continue, with 132 kV line 1L37 SAY-MSA normally operated open at the SAY end. Whenever line 2L48 SAY-MSA is open the line 1L37 will be closed at SAY to allow a limited level of power transfer between SAY and MSA.

5. System Studies and Results

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

5.1 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 Narrows Inlet project’s 40 MW power injection on system voltages and transmission elements loadings at nearby BCH substations.

In this System Impact Study, no overload on the nearby circuits has been identified. Steady state voltage levels at nearby substations were found to be acceptable.

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 5-1. It can be observed from the tables that there is no abnormal voltage or circuit overload under system normal conditions.

Prior to the Narrows Inlet project, there are existing thermal overloads in the Cheekye (CKY) area’s 132 kV transmission system under single contingency situations. The CKY area Remedial Action Scheme (RAS) responds to remove these overloads.

The single contingency studies have indicated that with Narrows Inlet generation added the pre-existing overloads on 1L31 are exacerbated for loss of MSA T1/T5. While CKY area RAS will continue to be relied on to address 1L31 thermal overloads, a direct transfer trip of 1L37 following MSA T1 or MSA T5 contingency will be required. Refer to study results for system normal and for contingency cases in Table 5-1, below. The notes #2 to #4 below the table describe the corrective actions that remove the overloads shown for the first three of the contingency cases.

The Narrows Inlet Project will not be allowed to operate in an island configuration. Power quality type protection can be used to serve the anti-islanding purpose, and such a protection scheme will need to be installed within the IC’s facilities.

Table 5-1: Power flow Contingency Study Results

(Pre-outage condition: 2018 LS with 40 MW injection from Narrows Inlet at the POI)

System Condition	Bus Voltages (per unit on 132 kV base)					Power flow (MW)					
	POI	CKY 132	GIB 132	SEC 132	MSA 132	1L31 at GIB	1L31 at BOX	1L32 at SEC	1L35 at MSA	MSA T5 230/132	CKY T4 230/132
System Normal	1.046	1.047	1.054	1.055	1.045	15.7	30	13	-59	99	59
Loss of MSA T1/T5	1.049	1.039	1.023	1.040	1.047	112 (191% I)	124 (106% I)	113	40	-	151
Loss of 1L35	1.052	1.031	1.031	1.043	1.050	79 (132% I)	92	78	-	40	120
Loss of CKY T4 230/132	1.056	1.083	1.078	1.070	1.055	-43	-29	-46	113 (103% I)	153 (108% I)	-
Loss of 1L31	1.050	1.045	1.060	1.060	1.049	-	-	-3	-74	114	27
Loss of 1L32	1.042	1.048	1.054	1.054	1.041	3	18	-	-71	111	47
Loss of 2L9	1.048	1.048	1.058	1.058	1.047	-4	11	-7	-77	117	40
Loss of 2L13	1.049	1.049	1.059	1.058	1.048	0	15	-3	-74	113	44

Notes:

1. The critical period for system planning purposes is the light summer load period. The ratings for the critically loaded elements in this system are the Summer continuous ratings as follows:
   - Rating of 1L31 (CKY-WFR tap) is 118 MVA at 132 kV with 49C conductor temperature limit, and 1L31 (WFR tap – GIB) is 59 MVA at 132 kV with 49C conductor temperature limit.
   - Rating of 1L32 (GIB-SEC) is 115 MVA at 132 kV with 90C conductor temperature limit.
   - Rating of 1L35 (MSA-SEC) is 112 MVA at 132 kV with 90C conductor temperature limit.
2. For the outage "Loss of MSA T1/T5" the overloads shown for 1L31 (91% and 6% above the line's rated capacity) will be removed by a direct transfer trip of 1L37 following a MSA T1 or T5 contingency and by the CKY area's Remedial Action Scheme (RAS) that will trip 1L45 to disconnect Clowhom and the nearby IPPs
3. For the outage "Loss of 1L35" the overload shown above for 1L31 (32% above rating) will be removed by the CKY area RAS that will trip 1L45 to disconnect Clowhom and the nearby IPPs.
4. For the outage "Loss of CKY T4" the overloads shown for 1L35 and for MSA T5 (3% and 8% above ratings) will be removed by the CKY area RAS that will trip the Skookum Creek IPP.

5.2 Transient Stability Study

A series of transient stability studies under various system operating conditions using the 2018 Light Summer case have been performed. The model of the generating project was based on the IC's data submission plus any additional assumptions where the IC's data was incomplete or inappropriate. The models and parameters of the IC's key components are shown in Appendix A.

Narrows Inlet generator units will be unstable after the loss of 1L35 due to a multi-phase line fault; out-of-step protection will need to be utilized to trip Narrows Inlet units out of service. The swing center for this instability event is located within the generating plants.

The stability performance will be unacceptable after the loss of MSA transformers T1 or MSA T5 in 2018 Light Summer. A direct transfer tripping scheme to trip 1L37 in 9 cycles will be required after MSA T1/MSA T5 fault initiation. Transformers MSA T1 and T5 are within the same protection zone.

For other severe cases, such as N-1-1 contingencies (one facility already out of service and another facility contingency), it is anticipated that the project's generators may become unstable and the swing center of the instability would be inside the plant. The IC must detect the loss of synchronism and trip their generators for out-of-step conditions. Out of step protection will be the responsibility of the IC.

The transient stability study results for 2018 Summer light load case are summarized in Table 5-2 below.

Table 5-2: Transient Stability Study Results (Pre-outage condition: 2018 LS with 40 MW injection from Narrows Inlet at the POI)

Case	Outage	3-phase fault location	Fault Clearing Time (cycles)		Generator Max Rotor Swing (deg.) (difference from initial angle)					Maximum Transient Voltage (pu)		Stability Performance
			Close end	Far end	RML IPP	BOX IPP	SKO IPP	ETR IPP	COM (BCH)	MSA 132	SEC 132	
1	1L31 CKY-GIB	Close to CKY	CKY 8	GIB 8	9	tripped	99	1	22	1.03	1.047	Acceptable
2	1L31 CKY-GIB	Close to GIB	GIB 8	CKY 8	9	Tripped	15	2	40	1.01	1.042	Acceptable
3	1L32 SEC-GIB	Close to SEC	SEC 8	GIB 9	13	12	14	2	86	0.91	0.86	Acceptable
4	1L32 SEC-GIB	Close to GIB	GIB 8	SEC 9	10	17	15	2	46	1.02	1.035	Acceptable
5	1L35 MSA-SEC	Close to MSA	MSA 8	SEC 9	unstable	19	7	7	64	0.94	0.94	Loss of synchronism
6	1L35 MSA-SEC	Close to SEC	SEC 6	MSA 9	20	24	7	4	74	1.058	0.88	Acceptable
7	MSA T5 LV side	MSA 132 kV	MSA 132 8	MSA 230 6	unstable	30	13	5	114	0.49	0.58	Loss of synchronism
7A	MSA T5 LV side, with RAS	MSA 132 kV	MSA 132 8	MSA 230 6	tripped by RAS	19	6	4	57	0.95	0.95	Acceptable
8	MSA T5 HV side	MSA 230 kV	MSA 230 6	MSA 132 8	95	35	11	36	96	0.72	0.75	Unacceptable
8A	MSA T5 LV side, with RAS	MSA 230 kV	MSA 230 6	MSA 132 8	tripped by RAS	19	6	4	57	0.95	0.95	Acceptable
9	MSA T1 HV side	MSA 500 kV	MSA 500 5	MSA 230 6	80	35	17	31	87	0.82	0.82	Acceptable
10	1L37 NITX-MSA	Close to MSA	MSA 132 8	NITX 132 23	tripped	9	10	6	40	1.046	1.053	Acceptable
11	1L37 NITX-MSA	Close to SAY, at 85% point from MSA	NITX 132 8	MSA 132 23	tripped	13	11	6	31	1.045	1.063	Acceptable
12	1L37 NITX-MSA	Close to NTIX, equal to 85% of MSA-SAY	NITX 132 8	MSA 132 23	tripped	14	12	7	33	1.045	1.063	Acceptable

Notes:

1. For Case 5 the out-of-step protection at the Narrows Inlet generators will be relied on to trip these generators for this unstable case caused by a multi-phase line fault on 1L35 near the MSA end. The swing center(s) would be inside the Narrows Inlet generating plants.
2. For both Case 7 and Case 8 a direct transfer trip of 1L37 will be needed to isolate the Narrows Inlet generators from the BCH system. This RAS action will be initiated by a trip of the MSA T1 & T5 tripping zone.

5.3 Analytical Studies

The voltage sags due to the IC's random energization of the 132/25 kV transformer at NITX using their 132 kV CB are expected to be within BC Hydro interconnection requirements. At the 132 kV point of interconnection on 1L37 the maximum voltage dip following a random energization would be approximately 25% instantaneous peak and about 5% rms (see Appendix B). The corresponding voltage dip at the NITX station's 132 kV bus would be about 9% rms.

The proposed connection of the IC's project into 132 kV line 1L37 and the normally open operation of this line at the SAY end will create a potential for severe temporary overvoltages. These overvoltages can occur if there are too few generators on-line when the IC's generating facility becomes isolated due to any opening of the MSA end of line 1L37. The overvoltage is caused by a positive sequence series resonance involving the IC facility's equivalent source impedance and the 132 kV line charging capacitance. It will be necessary to delay the opening of the MSA end of line 1L37 for all non-protective trips (i.e. trips originating from local or remote supervisory) and also implement a DTT to disconnect the IC's facilities from the BC Hydro system. In addition, a line terminal surge arrester (132 kV IEC3) will be needed on line 1L37 at MSA as a backup for this overvoltage condition in case the DTT is not in-service. Appendix B shows the PSCAD simulation results for this event of a "non-fault" abrupt opening of 1L37 at MSA for two scenarios: all of the IC's generators on-line, and only one generator (7.8 MVA) on-line. Note that these two simulations do not have the surge arrestor modelled, to highlight the overvoltages.

The above observations about transformer energization and temporary overvoltage are based on assumptions that:

- The IC's NITX station 132/25 kV transformer has configuration Star grounded/Delta.
- The short circuit level at the 132 kV POI from the BCH Transmission System under normal operating conditions is about 1200 MVA.

5.4 Fault Analysis

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

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

The BCH station work will include the addition of a surge arrestor at station MSA on the 1L37 line terminal. No equipment changes are needed at the Pender Harbour (PHR) station when the Tyson Creek generating station is removed from the PHR 25 kV feeder as part of the IC's project.

5.5 Transmission Line Upgrade Requirements

No BCH line upgrade work has been identified in this study.

BCH will provide the required "T" connection on circuit 1L37 with three 132 kV line disconnects at the POI by constructing the line tap structure and a disconnect structure to provide a connection for the IC's 132 kV line; the disconnect switch will be used to isolate the IC's facilities from the BCH system. Additional right-of-way and anchor easements may be required to accommodate the tap connection, and vegetation clearing may be required. An illustrative diagram of the 3-disconnect switch is shown in Figure 5-1.

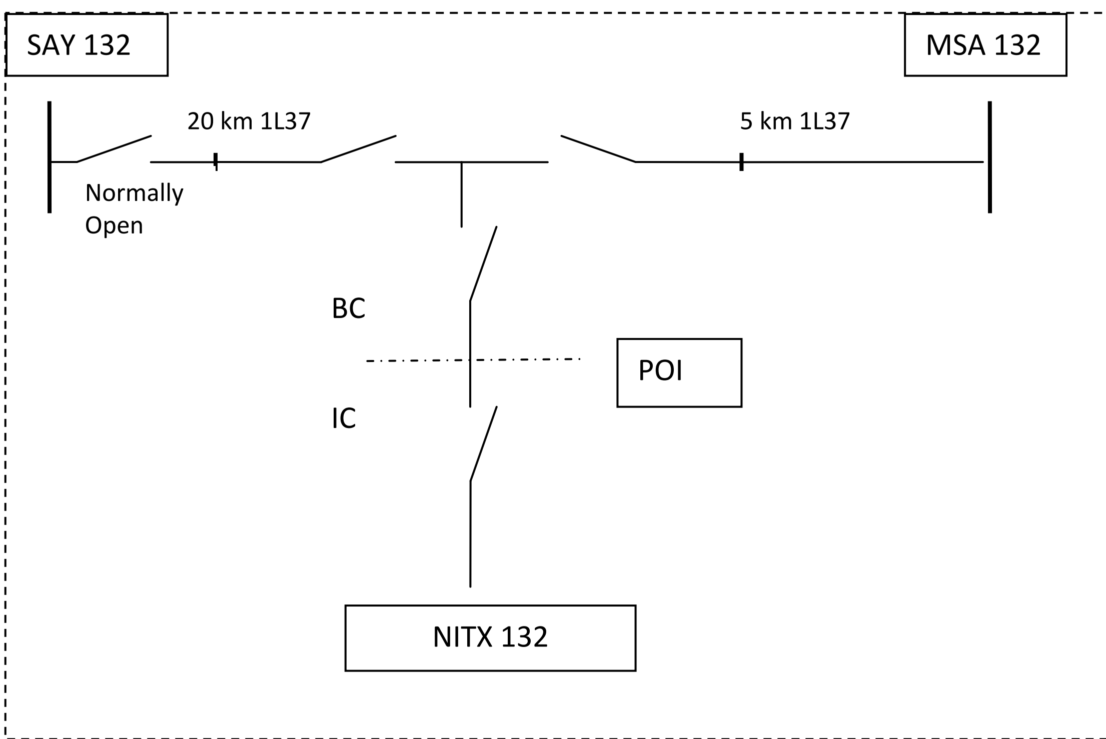


Figure 5-1 Arrangement of Disconnects at the POI

In addition, BCH will supply and install approximately 5 km of ADSS 48 strand fibre from MSA to the POI on 1L37, and will splice to the IC's fibre at the POI.

5.6 Protection and Control

Protection Work Required by BCH:
Malaspina (MSA)

- Replace existing MSA 1L37 line protection (currently electro-mechanical relays) with dual-primary relays in a stepped distance/DUTT configuration.
- Replace existing "Malaspina Separation Scheme" with a pair of RAS controllers.
- Review relay coordination of 1L35 and area.

Saltery Bay (SAY)

- Revise 1L37 relay settings to accommodate new relaying at MSA terminal of 1L37 and the tapped Narrows Inlet generation.

Pender Harbour (PHR)

- Revise existing PHR 25F53 relay settings to reflect removal of Tyson Creek IPP.

Protection Work Required by the IC:

- At the 132/25 kV collector station (NITX), provide 132 kV line protection that is compatible with BCH's line protection at the other terminals of the tapped 132 kV line.
- Provide entrance protection and power quality protection
- Provide out of step protection for the generators.

Summary of the control requirements for BCH and for the IC:

- The IC's SCADA data is required to be sent to BCH in accordance with the TIR, including required telemetry and status information.
- BCH will route the IC's telemetry and status to the appropriate Data Collection Platform (DCP). BCH control centers will reconfigure the existing equipment to accommodate the new IC, include the generator into the network model, and add the new telemetry and alarm points.

Control Work Required by BCH:

Alarm systems.

- Provide alarms for the new equipment and protection systems in accordance with standardized alarm guidelines.

Malaspina (MSA)

- Provide line telemetry via line protection relays for 1L37.
- Provide alarms as required for the new protection relays.
- Provide remote data access of the two new line relays at MSA.

- Revise MSA local control for 1CB5/6 to delay all local tripping and key DTT to Narrows Inlet's collector station NITX when the second breaker is being manually tripped.

BCH Control Centres.

- From the closest BCH station that communicates with the IC site, route the IC's telemetry and status to the closest DCP site (assumed to be ING DCP) and make associated connections and re-configurations. Update the existing database and displays at FVO/SIO to accommodate this new IC and update the network model to show the new generators.
- If existing Tyson Creek telemetry is moved to the new continuous telemetry connection, remove the existing dial-up connection at Ingledow IPP2 Data Concentrator.
- In association with the station work, update the database and displays at FVO and SIO to accommodate the alarm and telemetry additions/revisions.

Control Work Required by the IC:

- Provide the required telemetry and status information (per TIR) via a DNP3 RTU and route this information into the telecommunication channel to BCH.

5.7 Telecommunications

Assumptions:

- BCH will have no control of the IC.
- The fibre system will consist of the 5 km of ADSS 48 strand fibre from MSA to the POI (installed by BCH) and the same fibre on the IC's 132 kV line, installed by the IC.
- A channel bank will not be required at the IC's collector station (i.e. all circuits can be connected directly to fibre).
- The revenue metering circuits will be carried on the fibre between MSA and the IC's station NITX.

List of the required telecom circuits:

- A non-redundant WECC Class 2 DTT from MSA to NITX to trip the IC's 132 kV line at that location.
- For the NITX station, a SCADA circuit RS-232, minimum speed 9600 bps off MSA DCP.
- Revenue metering circuits (main and backup) from NITX to BCH.

Communication alternatives that were considered before the fibre option was selected as the lowest cost option:

- Fibre from MSA to NITX, using the existing BCH wood pole line (5 km from MSA to the POI, with some expectation of multiple pole replacements).
- Microwave from MSA to NITX was considered but there is no clear microwave path and no viable passive reflector sites.

Telecom Work Required by BCH:

- Supply and install 5 km of fibre between MSA and the POI .

At Malaspina station (MSA)

- Terminate the fibre from NITX.
- Install a teleprotection device, PDR2000 or equivalent, connected to the fibre facing the IC.
- Cross connect the IC's SCADA circuit from fibre to the DACS for connection to MDN DCP.
- Cross connect the revenue metering circuits from fibre to the DACS.

Telecom Work Required by the IC:

- Supply and install the fibre from NTIX to the POI.
- Provide telecommunications facilities for a continuous connection to BCH's closest BCH station with appropriate telecom facilities.
- The IC is required to provide a communications link for remote interrogation of the PPIS equipment by BCH servers.
- Move the telemetry for Tyson Creek from the existing dial-up connection to the new continuous connection.

5.8 Islanding

Islanded operation will not be arranged for this project. A direct transfer trip (DTT) from MSA to the IC's NITX station will be required to isolate the IC, as described earlier. 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 unit. The settings of these protective relays must conform to existing BCH practice for generating plants so that the generators will not trip for the ranges of off-nominal voltages and frequencies as given in the TIR.

5.9 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 will be required to apply for an Electricity Supply Agreement.

6. Distribution System Removals and Changes

Tyson Creek (TYS) powerhouse currently connects to a POI on BCH's 25 kV distribution feeder 25F53 from Pender Harbour (PHR) 132/25 kV station. The TYS connection to that POI is via a private 20 km line from the TYS switchyard. As part of the Narrows Inlet Project the POI for TYS will change from the existing POI to the new project's POI on BCH 132 kV transmission line 1L37. These removals and changes will be needed on the BCH distribution system:

- At the existing 25 kV POI remove a recloser, bypass switch, and load break switch.
- Modify the transformer and secondary conductor connections to a nearby BCH load customer.
- Make documentation changes related to the change in the TYS connection.

- The estimated cost to implement the above work is $103,087.
- All costs related to the decommissioning of the assets and changes to the BCH system as a consequence of the POI change will be tracked separately and paid for directly by the customer. The Customer will be required to provide a cash deposit in this amount in advance of the commencement of the work.
- The customer will be responsible for actual costs.

7. Revenue Metering

Specific metering information is provided in Table 7-1. The loss compensation parameters need to be calculated during implementation. The Tyson Creek generating station already has metering and so is not listed in the table.

Table 7-1: Metering Specific Information

IC Voltage	138 kV
Metering Voltage	138 kV(NITX) 25 kV(RML) 25 kV(RMU) 25 kV(CKW)
Maximum Power Injection	40 MW (NITX) 7 MW (RML) 7 MW (RMU) 19 MW (CKW)
Max Current	~167 Amps @ 138 kV (NITX) ~162 Amps @ 25 kV (RML) ~162 Amps @ 25 kV (RMU) ~439 Amps @ 25 kV (CKW)

<u>Point-of-Metering</u>	Primary side of the main 132 kV/25 kV transformer (NITX) Primary side of 25 kV/4.16 kV transformer (RML) Primary side of 25 kV/4.16 kV transformer (RMU) Primary side of 25 kV/13.8 kV transformer (CKW)
Voltage Transformers	3 x VTs (L-Grd) – 78000-120-120V (NITX) 3 x VTs (L-Grd) – 14400-120-120V (RML) 3 x VTs (L-Grd) – 14400-120-120V (RMU) 3 x VTs (L-Grd) – 14400-120-120V (CKW)
Current Transformers	3 x CTs 200x400-5-5A (NITX) 3 x CTs 200-5-5A (RML) 3 x CTs 200-5-5A (RMU) 3 x CTs 500x1000-5-5A(CKW)
COD	November 2017

Note:
1. Customer to provide accurate line length from point of metering to the point of interconnection for each individual station.

Refer to Appendix C for Revenue Metering Requirements.

8. Cost Estimate and Schedule

The non-binding good-faith cost estimate for Interconnection Network Upgrades required to interconnect the proposed project to BCH Transmission System is $ 3.92 million (including 20% contingency). An accuracy range of -35% to +100% is applied to this cost estimate. The estimate includes:

- Install one surge arrestor at MSA.
- Install a tap and three 138 kV disconnects near the POI.
- Upgrade 1L37 protections, alarms and SCADA at MSA and SAY.
- Replace “Malaspina Separation Scheme” with new RAS controllers.
- Install revenue meters

Excluded from this estimate are:

- Outages and related disruptions;
- First Nations consultation and accommodation;
- The Revenue Metering cost $208k, and
- BCH work to do removals and changes at the existing 25 kV POI for TYS, $103,087.

It is expected that the BCH work can be completed in approximately 18 months from project approval, and this assumes that all necessary funding approval, property acquisition, permits, materials and outages are available in time.

9. Conclusions and Discussion

In order to connect the Narrows Inlet Project to the BCH Transmission System at the POI, this SIS has identified the following issues and requirements.

- A "T" connection on line 1L37 with three 138 kV disconnects will be created at the POI.
- A direct transfer trip (DTT) scheme will be required to disconnect Narrows Inlet generation for MSA T1 or T5 outages.
- To prevent overvoltages the no-fault opening of 1L37 at MSA will be delayed so that Narrows Inlet will be tripped before 1L37 opens.
- The 1L37 line protection will be replaced by new relays. The IC is responsible to provide line protection at their NITX 132 kV station for their 132 kV tap line to the POI.
- An ADSS fibre optic line will be needed from NITX to MSA station via the POI. BCH will supply, install, and terminate the fibre optic portion between MSA and the POI. The IC will supply, install, and terminate the fibre optic portion between NITX and the POI.
- Out-of-step protection will be required at the IC's generators, provided by the IC.
- Islanded operation will not be arranged. Power quality protection will be required to prevent/mitigate possible inadvertent islanded operation.
- During outages of BCH's 230 kV line 2L48 MSA to Saltery Bay (SAY) the line 1L37 MSA-SAY will be operated closed to provide the backup supply. In this operating condition the Narrows Inlet generators will need to be disconnected from the BCH system.
- Associated with the interconnection project there will be BCH protection, control, and telecommunication work in the related transmission lines, substations, and control centers.
- The project will change the 25 kV POI for the existing generator at Tyson Creek (TYS) to the Narrows Inlet Project's POI. BCH will need to do removals and changes at the location of the present POI on Pender Harbour (PHR) feeder 25F53.
- The non-binding good-faith cost estimate for Interconnection Network Upgrades required to interconnect the proposed project to BCH Transmission System is $3.92 million, and the estimated time to complete the Interconnection Network Upgrades is 18 months after project approval. The work required within the IC facilities or the Revenue Metering facilities is not part of Interconnection Network Upgrades. The BCH work to do removals and changes at the existing 25 kV POI for TYS is also not included in the cost estimate of the Network Upgrades.

Appendix A – Dynamic Models

Generators

CKW generators G1, G2 :
Rating 10.55 MVA, 9.5 MW, 13.8 kV; +0.90, -0.90 pf, Ra= 0.0026 pu

Unit	Model	T'do	T"do	T'qo	T"qo	H	D	Xd	Xq	X'd
CKW	GENTPJU1	6.5	0.035	1.25	0.035	1.11	0.0	1.65	1.60	0.28
		X'q	X"d	X"q	Xl	$S_{G1.0}$	$S_{G1.2}$	K_{is}		
		0.65	0.19	0.19	0.15	0.07	0.18	0.0		

RMU generator G1 :
Rating 7.77 MVA, 7.0 MW, 4.16 kV; +0.90, -0.90 pf, Ra= 0.0070 pu

Unit	Model	T'do	T"do	T'qo	T"qo	H	D	Xd	Xq	X'd
RMU	GENTPJU1	6.5	0.035	1.25	0.035	1.153	0.0	1.65	1.60	0.28
		X'q	X"d	X"q	Xl	$S_{G1.0}$	$S_{G1.2}$	K_{is}		
		0.65	0.19	0.19	0.15	0.07	0.18	0.0		

RML generator G1 :
Rating 7.77 MVA, 7.0 MW, 4.16 kV; +0.90, -0.90 pf, Ra= 0.0070 pu

Unit	Model	T'do	T"do	T'qo	T"qo	H	D	Xd	Xq	X'd
RML	GENTPJU1	6.5	0.035	1.25	0.035	1.056	0.0	1.65	1.60	0.28
		X'q	X"d	X"q	Xl	$S_{G1.0}$	$S_{G1.2}$	K_{is}		
		0.65	0.19	0.19	0.15	0.07	0.18	0.0		

TYS generator G1 :
Rating 10.33 MVA, 9.3 MW, 4.16 kV; +0.90, -0.90 pf, Ra= 0.0042 pu

Unit	Model	T'do	T"do	T'qo	T"qo	H	D	Xd	Xq	X'd
TYS	GENTPJU1	5.32	0.039	0.0	0.35	1.11	0.0	2.3	0.713	0.34
		X'q	X"d	X"q	Xl	$S_{G1.0}$	$S_{G1.2}$	K_{is}		
		0.713	0.25	0.25	0.15	0.08	0.25	0.0		

Excitation Systems –

CKW – exciter model AC8B

Unit	Tr	Kp	Ki	Kd	Td	V_{PIDMAX}	V_{PIDMIN}	Ka	Ta	V_{Rmax}	V_{Rmin}
CKW	0.0	200.	145.	78.	0.1	99	-99	0.15	0.004	9.6	-8.6
	Kc	Kd	Te	Ke	V_{FEMAX}	V_{FEMIN}	E1	SE1	E2	SE2	
	0.1	0.3	0.25	1.0	10	0	5.36	0.05	7.14	0.18	

RMU – exciter model AC8B

Unit	Tr	Kp	Ki	Kd	Td	V_{PIDMAX}	V_{PIDMIN}	Ka	Ta	V_{Rmax}	V_{Rmin}
RMU	0.0	80.	30.	10.	0.1	99	-99	0.15	0.004	9.6	-8.6
	Kc	Kd	Te	Ke	V_{FEMAX}	V_{FEMIN}	E1	SE1	E2	SE2	
	0.1	0.3	0.25	1.0	10*	0*	6	0.05	8	0.18	

RML – exciter model AC8B

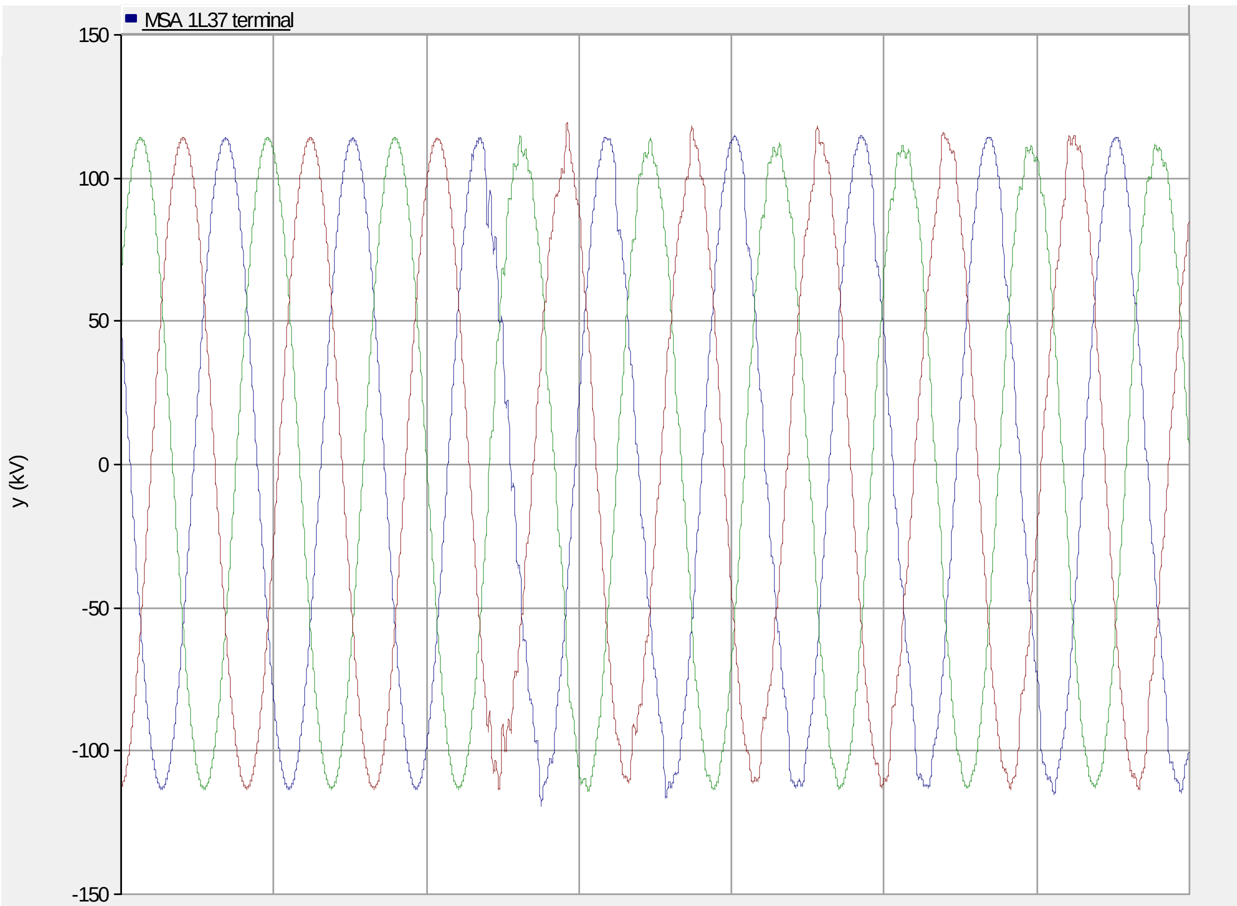
Unit	Tr	Kp	Ki	Kd	Td	V_{PIDMAX}	V_{PIDMIN}	Ka	Ta	V_{Rmax}	V_{Rmin}
RML	0.0	80.	30.	10.	0.1	99	-99	0.15	0.004	9.6	-8.6
	Kc	Kd	Te	Ke	V_{FEMAX}	V_{FEMIN}	E1	SE1	E2	SE2	
	0.1	0.3	0.25	1.0	10	0	6	0.05	8	0.18	

TYS – exciter model ESAC8B

Unit	Tr	Kp	Ki	Kd	Td	Ka	Ta	VRmax	VRmin	Te	Ke	E1	SE1	E2	SE2
TYS	0.0	80.	20.	10.	0.02	1.0	0.00	6.84	0.0	0.5	1.0	4.28	0.05	5.7	0.2

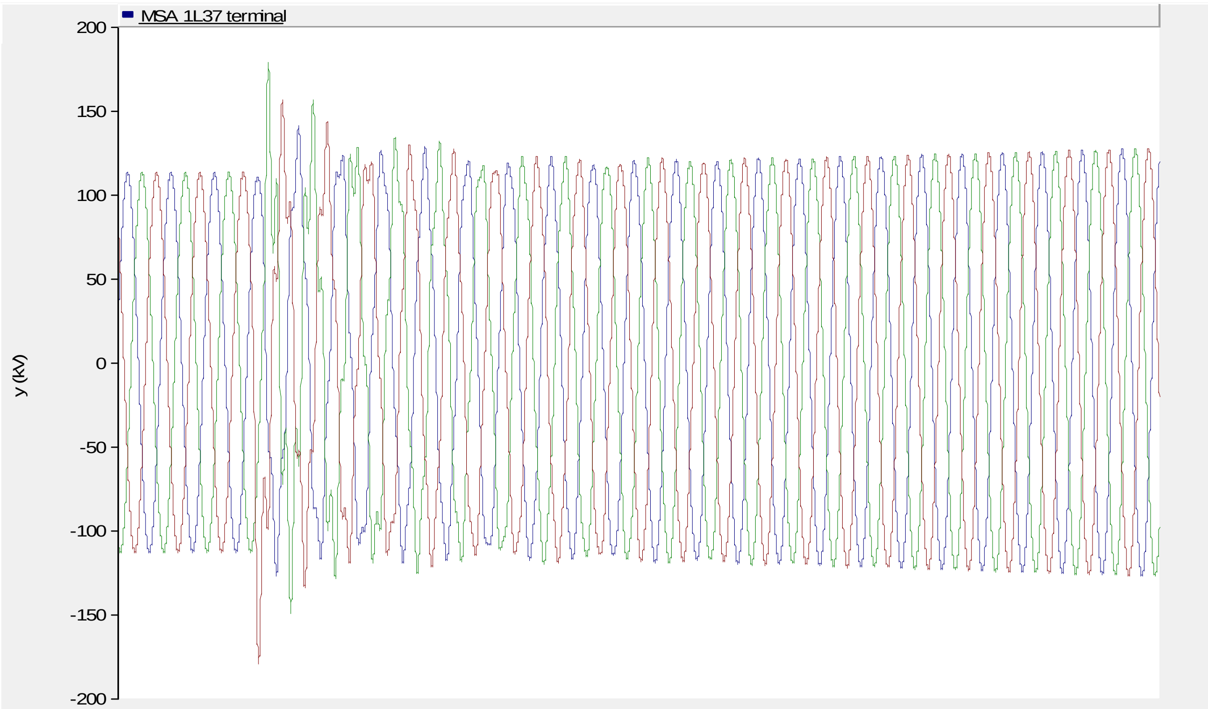
Appendix B – Selected Plots of Analytical Studies

- Transformer Energization:

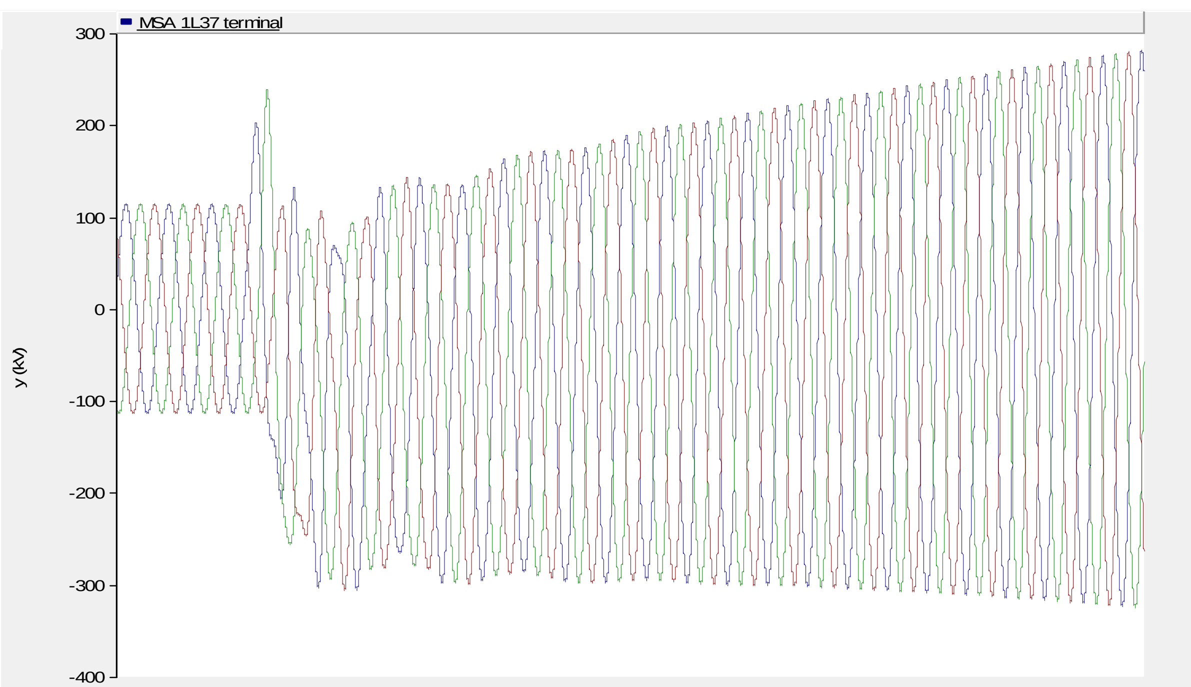


– Representative random uncontrolled TX energization. MSA 132kV bus voltage.

Non-protective abrupt opening of 1L37 at MSA with maximum and minimum MVA machine scenarios at Narrows Inlet:



– TOVs at MSA 138kV 1L37 line terminal following non-protective abrupt opening of 1L37 with Narrows Inlet maximum MVA machine online.



– TOVs at MSA 138kV 1L37 line terminal following non-protective abrupt opening of 1L37 with Narrows Inlet minimum MVA machine online (only 7MVA).

Appendix C – Revenue Metering Requirements

There will be four (new) metering points at the following location: at the Narrows Inlet collector station, Lower Ramona power plant, Upper Ramona power plant and Chickwat power plant.

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 for each metering point. The meters will be supplied and maintained by BC Hydro. The main meter will be leased by BCH to the PG. As per federal regulations, the meter will be periodically removed and re-verified in a MC authorized laboratory. Main and backup bi-directional load profile interval meters are required to measure the power received and the power delivered (by BCH to the PG) during each 30 minute time period. 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;

The remote read load profile revenue metering should be in accordance with the BCH Requirements for Complex Revenue Metering. The latest version of this document is published at BC Hydro webpage under Forms and Guides. The revenue metering responsibilities and charges (Power generator (PG) and BCH) shall be in accordance with Section 10 (10.1 and 10.2). For details about the specific responsibilities, see table on pages.23-25.

The POM shall have a dedicated communications line (landline or alternative technologies e.g. cellular, fiber optic, microwave, satellite etc. subject to BCH approval) available for revenue metering use only. If there is digital cell phone coverage for data, BCH will supply the wireless communications. In this case, there will an incremental cost for the PG. BCH MV-90 Server must be able to access and download data from the revenue meters remotely as they do when they dial in a site using a standard phone line (wireless or landline). For more details, please, refer to Section 8 of BCH Revenue Metering Requirements for Complex Metering

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. A 3-element metering scheme with 3 CTs and 3 VTs connected L-N (Grd) shall be used. The CTs and VTs must be pre-approved by BC Hydro's Revenue Metering Department. The PG should send an email to BCH RMSM stating the model/maker/ratio/MC approval numbers, etc. A list of approved models is available at Measurement Canada (MC) website under "Notice of Approval Database Section".

For Stand-Alone VTs and CTs, the H1 terminal of the VTs shall be connected on the BC Hydro side of the CTs. The revenue metering VT and CT secondary windings are not permitted to be shared with any other equipment therefore no other devices shall be connected to the revenue metering VT and CT secondary windings.

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). The key interlocks shall prevent opening 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. "*

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 PG or its consultant shall provide the line parameters data and the power transformer testing data to BC Hydro.

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.

For a complete list of the information needed in the design stage, see below:

Information required in the design stage includes:

1. Length of secondary cables
2. Single Line Diagram showing CTs, VTs, cabinets, all generating stations connecting to the POI
3. Identify whether revenue metering cabinets are indoors or outdoors - implication on whether cabinets need to be insulated
4. Communication medium contemplated to relay revenue metering data
5. 3-line diagram of the interconnection of the revenue metering CT & VT
6. Scaled Site Plan showing the relative location of the meter cabinet to the CT & VT (drawing showing the footprint for the sub)
7. Private power line parameters data and/or the power transformer testing data signed and stamped by a professional engineer (if applicable)
8. 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)
9. A simplified version of the lockout access steps to the revenue metering CT & VT (if applicable)
10. Location of the Meter Cabinet and verification of dedicated 120V AC 15A circuit for the meter cabinet - as per section 6.4 of BCH requirements
11. Contact name/phone on site for equipment/material delivery.
12. Mailing Address for the site (normal mailing address)

13. Interconnection Customer Billing Information
14. Operational Site Access for BC Hydro Meter Tech (for metering installation, maintenance, etc.)