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Newfoundland and Labrador Hydro



Feasibility Study of

Hydraulic Potential of Coastal Labrador

Phase 2: Project Definition Phase

Final Report

March 2013

HATCH™

Newfoundland and Labrador Hydro
Feasibility Study of Hydraulic Potential of Coastal Labrador

Phase 2: Project Definition Phase

Final Report

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Executive Summary

In Phase 2, Hatch has undertaken a feasibility and project definition study of four small hydro sites that were screened in Phase 1 as having the potential to serve the Coastal Labrador towns of Hopedale, Makkovik, Charlottetown (CHT), Port Hope Simpson (PHS), and Mary's Harbour (MSH). The direction prescribed by Newfoundland and Labrador Hydro (NL Hydro) was to have one site for each of the three communities of Hopedale, Makkovik and the combined towns of CHT/PHS/MSH. The four sites included two that were competing alternative sites to provide power from one hydro plant to CHT/PHS/MSH. It was recommended by Hatch and was decided to carry these two sites through Phase 2 since the evaluation and need to mitigate the environmental impacts of one of these could eventually lead to it being dropped as a candidate site.

In addition, at the end of Phase 2 NL Hydro requested Hatch to evaluate the potential of diesel displacement opportunities with storage hydro schemes serving the communities of CHT, PHS, MSH and the town of St. Lewis (STL), based on the sites studied during Phases 1 and 2. The most practical configuration of the storage options was a site on the Gilbert River to serve CHT plus a site on the St. Lewis River to serve PHS/MSH/STL. An alternative to the St. Lewis River storage site would be one on the Alexis River to serve PHS/MSH/STL. The description of hydro storage potential is presented in this report as Annex – Potential Storage.

The key activities in Phase 2 were: *(a)* additional site reconnaissance and verification geographical positioning system (GPS) measurements at various sites; *(b)* a more in-depth geotechnical assessment of site geology; *(c)* more detailed mapping (LiDAR) at the four sites and over its upstream reach; *(d)* the development of hydrological sequences of mean daily flows at each of the four sites covering the period 1978-2011; *(e)* a quick analysis of three alternative site locations for the headworks of Site 8 (8A, 8B and 8C) to determine its optimum location; *(f)* revised scheme layouts and engineering designs based on the updated site mappings; *(g)* cost estimates and project schedules; *(h)* preparation of new estimates of potential energy generation on an inter-year basis; and *(i)* an economic analysis of each site using discounted cash flow techniques applied to updated site development costs and energy benefits based on NL Hydro's 2012 displacement diesel fuel costs of generating electricity.

The key activities for the evaluation of the storage hydro sites were: (a) additional aerial photography and detailed digital mapping of Site 5, Site 8D (downstream of Site 8C) and Site ALX-B (upstream of Site ALX); (b) estimates of required reservoir sizes and water level operating limits; (c) revised scheme layouts (high dams and engineering designs); (d) verification of reservoir yields; (e) evaluation of firm power with a reliability above 95%; (f) consideration of annual hydro variability of storage and run-of-river schemes; (g) cost estimates of the storage schemes, and schedules; and (h) an economic analysis that estimated the levelized unit cost of energy from hydro-storage schemes.

The results of the more detailed and updated mapping for project definition required some engineering design changes to the Phase 1 hydro scheme layouts. MK S-2 required a longer penstock. Site ALX powerhouse was moved to the left bank of the Alexis River to obviate the need for a river crossing to get to the powerhouse. The examination of alternative options for locating Site 8 focussed on the mitigation of potential impacts on the upstream falls opposite the tourist/fishing lodge being constructed on the St. Lewis River. The optimum location chosen is 8C, approximately 260 m downstream of original Site 8, based on its least cost of civil works. In addition, the installed capacities proposed at Sites 11, 8 and ALX were adjusted downwards to be more in line with the 2037 load forecast. At Sites 8 and ALX the installed capacity went from 5 MW to 4.4 MW; at Site 11, 2 MW was reduced to 1.5 MW. The Phase 2 definition study resulted in lower estimated project costs for sites 11, 8 and ALX.

Hydrological sequences of mean daily flows were developed for all sites and covered the period 1978-2011. The Phase 2 mapping of the four sites covered their headpond areas and demonstrated that there is no significant storage in the headponds formed as a result of the construction of diversion dams. There would be no potential for providing flexibility in power generation by peaking during periods of low flow. All four sites would therefore operate as run-of-river hydro plants.

The flow sequences and the proposed plant parameters were used as input to a spreadsheet computer model that estimated daily energy generation at all sites. The energy streams were converted to energy benefits by applying an energy price equivalent to the fuel displacement cost for diesel generation for the three communities of Hopedale, Makkovik and CHT/PHS/MSH. Fuel displacement costs for generation at 2012 prices were provided by NL Hydro.

An economic analysis of the four sites using discounted cash flow techniques evaluated the economic viability of the prospective hydro schemes. The main inputs to the economic analysis were: the cash flow of construction costs, operation and maintenance costs, and, the energy benefits. Both a 25-year and 50-year project life were analyzed. The discount rate adopted was 7%. The levelized unit energy cost (LUEC) for the four sites was also estimated.

Key Findings

On the basis of the Phase 2 definition study, three of the preferred sites would be technically feasible but there is a disparity in their economic viability.

An evaluation of energy utilization on a monthly basis showed that Site 11 and Site 8C performed the best in meeting the 2037 monthly energy demand. Site 11 met demand in all months which was expected given its high capacity factor of 93%. Site MK S-2 failed to meet energy demand in ten months of the year and there was little or no generated energy from the site in five of those ten months. Site 8C met the forecasted demand for nine months of the year and in the remaining three months it met approximately 53% to 66% of demand energy.

A summary of the economic analysis and the estimated LUEC of the four run-of-river hydro sites is given in Table ES-1. Site 11, Site 8C and Site ALX have positive net present values (NPV) for both the 25-year and 50-year project periods. The parameters in Table ES-1 are for the 50-year project period. The highest NPV is for Site 8C; it also has the highest IRR and a benefit cost ratio (B/C) of 1.88. Site 8C is therefore judged to be the most economically viable site of the four sites. The second most attractive site is ALX. Site 11 has an IRR of 9.75% and a B/C ratio of 1.39. Site MK S-2 is not economically viable since it has a negative net present value over 50 years and its IRR is below the adopted discount rate of 7%. Site 8C has the lowest LUEC at $0.187/kWh while the value for Site ALX was $0.245/kWh. Both values are well below the fuel displacement cost of diesel generation of electricity.

It is recommended that Site 8C should proceed to the next design level with emphasis on environmental screening to better define upstream impacts. Should the impacts be substantial and cannot be mitigated, then Site 8C may be dropped. Site ALX, being the next most economically viable site, should also proceed to the next stage, since there is a possibility of opposition to the construction of Site 8C. Generation from the proposed small hydro plant at Site 11 would displace diesel generation at Hopedale, therefore its economical viability should be further assessed.

In relation to the evaluation of potential storage projects (Annex), three hydroelectric storage developments at Site 5B, Site 8D and Site ALX-B are technically viable but there is a disparity in their economic viability. It is not feasible to have a single hydro storage project to serve the four communities CHT, PHS, MSH and STL. A summary of the economic analysis and the estimated LUEC of the storage hydro sites is provided in Table ES-2.

The combined power and energy from Site 5B-2 (storage with 2,500 kW installed capacity) and Site 8C-2 (run-of-river at an installed capacity of 3,000 kW) satisfied the forecasted load demand for the four southern communities and has the most economic merit of the options evaluated. The LUEC on the demand side is $0.282/kWh and on the supply side is $0.233/kWh. Its development cost is estimated at $89 million. If Site 8C-2 cannot be constructed on the St. Lewis River, then the next economically attractive option is Site 5B-1 and ALX-B at a cost of $135.5 million with its LUEC of demand energy at $0.401/kWh and cost of supplied energy at $0.311/kWh.

Table ES-1: Results – Run-of-River Hydro Projects
Generation Capacities, Energy, Construction Costs and Levelized Cost of Energy

Site Number	Closest Community	Forecast Community Peak Load (2037)	Plant Installed Capacity	Average Annual Demanded Energy	Hydro Site Average Annual Generated Energy	% Demand Satisfied by Hydro	Estimated Project Cost *a/*	Cost/kW	2012 Cost of Energy (LUEC) *b/*
		(kW)	(kW)	(MWh)	(MWh)	(%)	($Millions)	($/kW)	($/kWh)
11	Hopedale	1,422	1500	9,538	9,538	100	38.0	25,300	**0.273**
MK S-2	Makkovik	1,020	1000	7,259	3,644	50	19.3	19,300	**0.404**
8C	CHT/PHS/MSH	4,353	4400	31,717	27,807	88	61.9	14,100	**0.187**
ALX	CHT/PHS/MSH	4,353	4400	31,717	17,676	56	51.3	11,700	**0.245**

Notes:

a/ In 2012 Canadian dollars; Owner's costs, financing/IDC, and southern Labrador interconnection costs are not included.
b/ Economic analysis period is 50-years; all costs and benefits are in 2012 prices.

Table ES-2: Results – Storage Hydro Projects
Generation Capacities, Energy, Construction Costs and Levelized Cost of Energy

Site Number	Communities Served	Forecast Community Peak Load, 2037 *c/*	Generation Scenario	Installed Capacity	Average Annual Demanded Energy	Cost	Cost/kW	2012 Cost of Demand Energy *d/*	2012 Cost of Supplied Energy *d/*
		(kW)		(kW)	(MWh)	($M)	($/kW)	($/kWh)	($/kWh)
5B-1 *a/*	Charlottetown	1848	Option # 1	2,100	11,045	43.7	20,800	0.345	0.235
8D	PHS/MSH/STL	2605	Option # 1	3,500	20,597	148.4	42,400	0.587	0.493
ALX-B	PHS/MSH/STL	2605	Option # 1	3,500	20,597	96.0	27,400	0.395	0.332
5B-1 + 8D	CHT & PHS/MSH/STL	4245	Option # 1	5,600	31,642	192.1	34,300	0.476	0.370
5B-1 + ALX-B	CHT & PHS/MSH/STL	4245	Option # 1	5,600	31,642	139.7	24,900	0.351	0.273
5B-2 + 8C-2 *b/*	CHT & PHS/MSH/STL	4245	Option # 2	5,500	31,642	89.1	16,200	0.240	0.199

Notes:

a/ Site 5B-1 delivers 1850 kW of firm energy to Charlottetown.
b/ Site 5B-2 would deliver 2300 kW of firm power with surplus energy over the demand at CHT exported to PHS/MSH/STL.
c/ Peak load based on historic load curve data.
d/ Economic analysis period is 50 years; discount rate = 7%.

1. Introduction

NL Hydro has carried out previous studies to evaluate the hydraulic and energy potential of hydro sites near Coastal Labrador isolated communities. Most Coastal Labrador communities depend solely on non-renewable diesel fuel to generate their electricity and energy costs are high due to the cost of diesel fuel (supply cost of fuel, handling and transportation). There is only one known existing mini hydro renewable energy development in Coastal Labrador, near the Town of Mary's Harbour. It is not currently in operation. Power demand from existing diesel plants in Coastal Labrador communities will potentially increase. NL Hydro commissioned in 2008 a study to do a preliminary assessment of alternative energy potential of the area. A follow-up study in 2009 was carried out by Hatch to review the hydraulic potential near Coastal Labrador communities. Approximately 36 mini/small hydro sites were evaluated at conceptual level along with their preliminary estimated costs.

NL Hydro retained Hatch in March 2012 to carry out a feasibility study of selected hydro sites with hydraulic potential to generate green energy at a competitive price compared to diesel generating plants. The communities identified for this study are – Hopedale, Makkovik, Charlottetown, Port Hope Simpson and Mary's Harbour. Figure 1-1 shows the locations of these towns.

The feasibility study has been undertaken in two phases: Phase 1 - Advance Screening and Phase 2 – Project Definition.

Hatch completed Phase 1 – Advance Screening of 11 potential sites in August 2012 and the report ranked the four most attractive hydro sites – one each to serve the communities of Hopedale and Makkovik and two alternative sites, either of which could serve the combined communities of Charlottetown (CHT), Port Hope Simpson (PHS) and Mary's Harbour (MSH). The Phase 1 report recommending the four sites was submitted to NL Hydro in August 2012.

The Phase 2 – Project Definition Studies commenced at the end of Phase 1. The first task completed under Phase 2 comprised a brief analysis and optimization of the two alternative sites that could service the combined communities of CHT/PHS/MSH. All planned definition phase tasks have been completed.

This report therefore focuses on the results of the Phase 2 study and reports on the recommendations regarding the viability of the development of each of four hydro sites to provide power to the five earmarked Coastal Labrador communities.



Figure 1-1
Community Locations
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro

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1.1 Background

1.1.1 Previous Coastal Labrador Hydro Studies/Data

NL Hydro provided several study reports and load forecasts to be used as the basis for the Feasibility Study of Hydraulic Potential of Coastal Labrador (named Coastal Labrador Hydro herein). A listing of the reports/documents relevant to this study that were provided by NL Hydro can be found in the Phase 1 report and are not repeated here.

1.1.2 Load Forecast for Labrador Communities

NL Hydro System Planning Division provided Hatch with long-term isolated system load forecasts for the communities of Hopedale (HPD), Makkovik (MAK), Charlottetown (CHT), Port Hope Simpson (PHS), and Mary's Harbour (MSH). The long-term forecast covered the period 2013 to 2063 (50 years) and reports forecast load for diesel rates (isolated) and interconnected rates under the following sub-headings – gross annual energy (kWh), net annual energy (kWh), gross peak power (kW) and net peak power (kW). A load forecast is simply an estimate of power demand at some future period and is one of the tools used for capacity planning. In the context of the Phase 1 screening study, Hatch chose a 25-year planning horizon based on its experience on other similar assignments. The load forecast for 25 years (to 2037) provided by NL Hydro is given in Table 1-1.

On an intra-year basis, peak load for CHT, MAK and MSH occurs during the spring or summer when there is fish processing. In the case of HPD, and PHS, the peak is during the winter months. No load shape data were provided with the Hydro load forecast.

The load forecast was used to establish the energy and power requirements projected at year 2037 (i.e., 25 years from present) and to fix the planned installed capacity at the hydro sites expected to service the respective communities or group of communities. The forecasted community loads in 2037 from the load forecast are as follows:

- Hopedale – 1422 kW
- Makkovik – 1020 kW
- CHT/PHS/MSH – 4353 kW

1.2 Phase 1 - Advanced Screening (Prefeasibility Study) 2012

The Phase 1 study was an Advanced Screening Study (Pre-feasibility/ FEL [Front End Loading]-2) of the 15 proposed/ potential sites outlined in NL Hydro's Request for Proposal. The sites were initially pre-screened to shortlist the best 13 sites, and a final step was shortlisting to a total of 11 sites, prior to the Phase 1 site visits. The key activities in Phase 1 included data collection and review, development of long-term site hydrology, topographical mapping, site visits and geological/ geotechnical assessment, site layouts, pre-feasibility construction cost estimates, annual energy estimates, a preliminary economic ranking of the unit cost of energy, and, a preliminary environmental screening.

Table 1-1: 25-Year Load Forecast for Coastal Labrador Communities

	Hopedale		Makkovik		CHT/PHS/MSH	
Year	Gross Energy (MWh)	Gross Peak (kW)	Gross Energy (MWh)	Gross Peak (kW)	Gross Energy (MWh)	Gross Peak (kW)
2012	4729	961	3703	836	13174	3474
2013	4989	1015	3757	847	14940	3759
2014	5105	1040	3810	859	15121	3804
2015	5211	1061	3865	870	15280	3844
2016	5328	1086	3911	880	15447	3885
2017	5428	1107	3953	889	15608	3926
2018	5534	1129	3994	898	15767	3966
2019	5686	1160	4030	906	15896	3999
2020	5774	1178	4066	913	16013	4027
2021	5862	1197	4102	921	16122	4053
2022	5943	1214	4137	929	16254	4085
2023	6017	1229	4167	935	16358	4111
2024	6091	1244	4197	941	16477	4139
2025	6166	1260	4226	948	16596	4169
2026	6240	1275	4256	954	16698	4193
2027	6314	1291	4286	960	16758	4209
2028	6389	1306	4315	967	16841	4230
2029	6463	1322	4345	973	16915	4248
2030	6537	1337	4375	979	16982	4264
2031	6605	1351	4405	986	17031	4276
2032	6666	1364	4434	992	17089	4291
2033	6726	1376	4464	998	17157	4307
2034	6787	1389	4488	1003	17210	4320
2035	6848	1402	4517	1010	17259	4332
2036	6909	1414	4547	1016	17308	4344
2037	6946	1422	4565	1020	17343	4352

A brief summary of the findings, of the 2012 Phase 1 – Advanced Screening Study is provided below.

(i) On the basis of the available information, all of the selected sites would be technically feasible for the construction of mini and/or small hydro plants.

(ii) There appears to be no showstopper environmental or land impacts (other than original Site 9, see below).

(iii) Based on the site reconnaissance, geotechnical assessments, scheme layouts and development costs, 11 sites were successfully screened to arrive at 4 preferred sites for the Phase 2 studies, as given in Table 1-2.

Table 1-2: Results of Preliminary Screening for Preferred Sites

Site	Benefiting Communities	Community Peak Load (2037), kW	Phase 1 – Proposed Installed Capacity, kW
11	Hopedale	1422	2000
MK S-2	Makkovik	1020	1000
8	CHT/PHS/MSH	4353	5000
ALX	CHT/PHS/MSH	4353	5000

A fifth site, Site 9, was originally included as a preferred Phase 1 site; however, the advanced screening site visit identified impacts on Sites 8 and 9 due to their proximity to a tourist lodge under construction on the left bank of the St. Lewis River, at the Site 9 location. Original Site 9, located at the falls adjacent to the tourist lodge, was therefore eliminated from consideration. It was necessary to confirm the water levels at Site 8 and at the base of the falls, and upstream of the falls to establish the viability of Site 8 and make a preliminary screening of the impacts relative to the tourist lodge development at that section of the river. These water level measurements were implemented during the Phase 2 site visit to assist in confirming the technical feasibility of Site 8 as a 5 MW capacity development for the CHT/PHS/MSH communities. It was established that original Site 8, (referred to as 8A) at a lower head could be constructed with no inundation (headpond) above the lower level at the base of the falls at the lodge. For optimization purposes, during Phase 2, based on the site visit and the detailed LiDAR mapping, two alternative Site 8 dam locations downstream of 8A were assessed. These two sites were consequently labeled Sites 8B and 8C. The result of the evaluation of the three alternative Site 8 locations was the ultimate selection of Site 8C, which is located between 8A and 8B, for the final analyses.

2. Scope of Work

2.1 Objectives and Summary of Scope of Work

NL Hydro is advancing the 2009 Review of Hydraulic Potential of Coastal Labrador by undertaking a screening and feasibility study of water power sites near the five communities identified in Section 1.

NL Hydro's Request for Proposals (RFP) for Engineering Services for the feasibility study is attached for information in Appendix A.

In Phase 1, the prime objective was to screen and assess 15 sites proposed by NL Hydro and to select the preferred sites that may be developed which could provide energy that would be more competitively priced than diesel fuel. This work was completed during the period of March to August 2012.

The objectives of Phase 2 are as follows:

- Perform a more detailed analysis, and preliminary engineering for the top four sites selected from the Phase 1 studies
- Prepare drawings based on a 30 percent engineering level
- Prepare project schedules and cost estimates for each site
- Present the findings and results in a final report.

The scope of work carried out by Hatch in Phase 2: Project Definition Phase to fulfill the objectives is summarized as follows:

- Carry out a Phase 2 site reconnaissance
- Based on the Phase 2 site visits, update the geotechnical information
- Data acquisition (LiDAR mapping and data)
- Develop facility layouts and complete preliminary design
- Power and energy analysis using site hydrological sequences
- Develop a detailed cost estimate for each site
- Develop a detailed project schedule for each site and determine cash flows
- Identify environmental impacts and provide a detailed engineering description of the projects
- Undertake a preliminary economic analysis
- Determine conclusions.

2.2 Approach to Phase 2

Phase 2 – the current study included more detailed analyses and investigations which were conducted on the highest ranked four sites selected from Phase 1. These are intended to advance the engineering and accuracy of the cost estimates and also conduct a preliminary economic analysis to show potential financial viability.

The acquisition of LiDAR survey information facilitated more detailed project layouts, quantity take-offs and construction cost estimates. The systems were further optimized, an updated environmental screening was undertaken and a benefit-cost and internal rate of return analysis was carried out at each site. Finally, the technical and financial viability of the preferred four sites was evaluated.

The four sites evaluated as part of this Phase 2 study are as follows:

- Site 11 near Hopedale
- Site MK S-2 near Makkovik
- Site 8 near Port Hope Simpson
- Site ALX near Port Hope Simpson

The location of each of the four sites relative to the towns is outlined in Figures 2-1, 2-2 and 2-3. Both Site 8 (8C) and ALX are carried throughout the Phase 2 studies to establish if one or both sites would be technically and financially feasible to serve the energy demands of CHT/PHS/MSH. Figure 2-4 shows the locations of the alternative Site 8 waterpower sites (8A, 8B and 8C), and the location of the upstream tourist/fishing lodge currently under construction.

2.3 Objectives and Scope of Work – Storage Projects (Annex)

The main objective of this study on storage potential was to evaluate hydroelectric storage sites among those previously screened that may satisfy power and energy needs of the four southern communities of CHT, PHS, MSH and STL. This evaluation focused primarily on the technical viability of storage and established the firm energy yield for a hydrologic reliability of 95% or greater. The broad concepts to achieve this objective were outlined; design layouts were prepared from recently completed topographic mapping; conservation reservoir volumes to be created by construction of dams were estimated; and, reservoir yield and draft rates verified. Detailed cost estimates from layout quantities were prepared, and an economic analysis that determined the levelized unit energy costs for sites was completed. In the potential storage study, the first task examined previously screened small hydro schemes and made approximate assessments of storage potential with or without high dams. An inspection of the data then led to the formulation of generation options with storage sites that may fully displace diesel generation. Two base generation options were selected which were then analyzed and studied in greater detail.

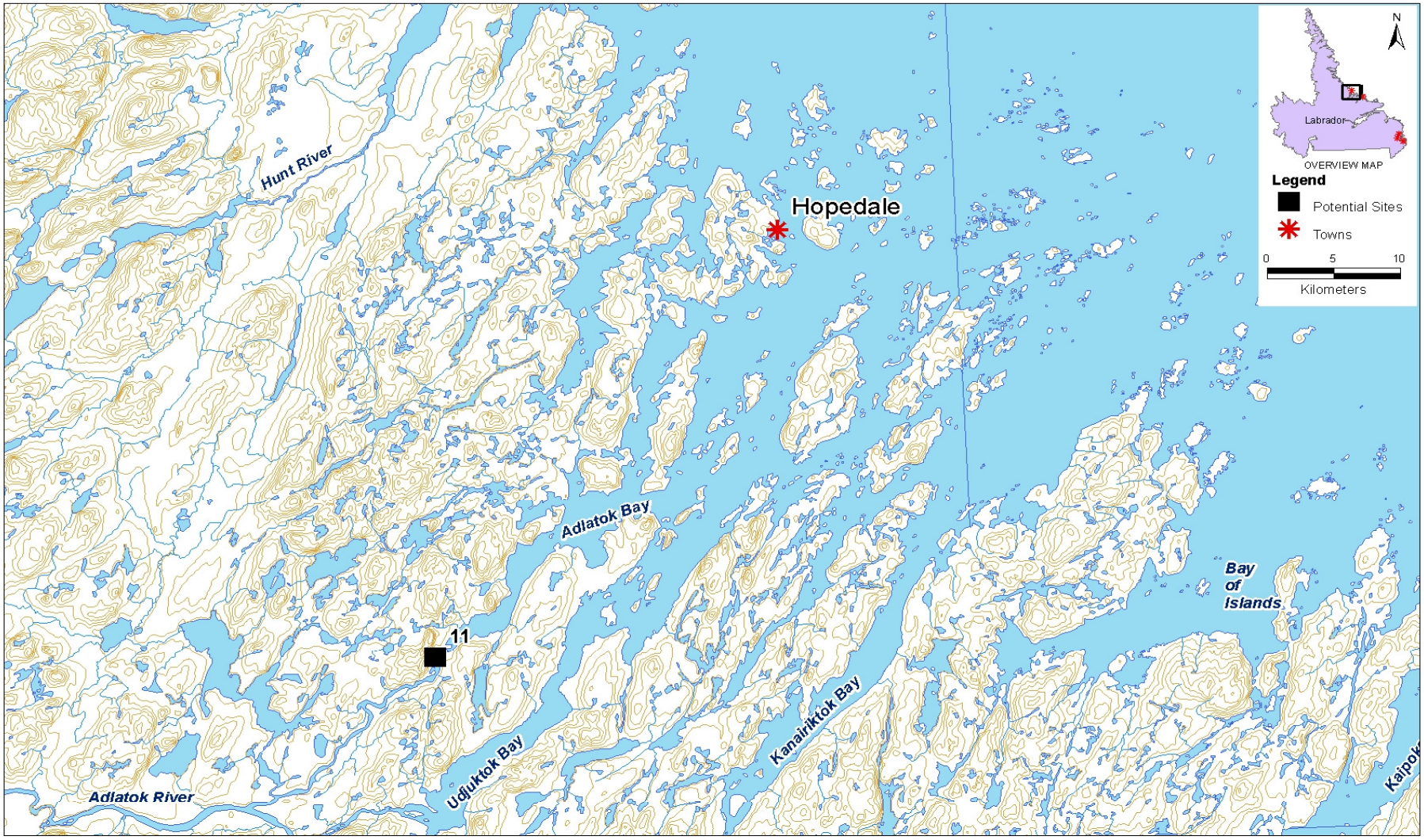


Figure 2-1
Hopedale Site Location
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro

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Figure 2-2
Makkovik Site Location
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro



Figure 2-3
Charlottetown, Port Hope Simpson, & Mary's Harbour Site Locations
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro

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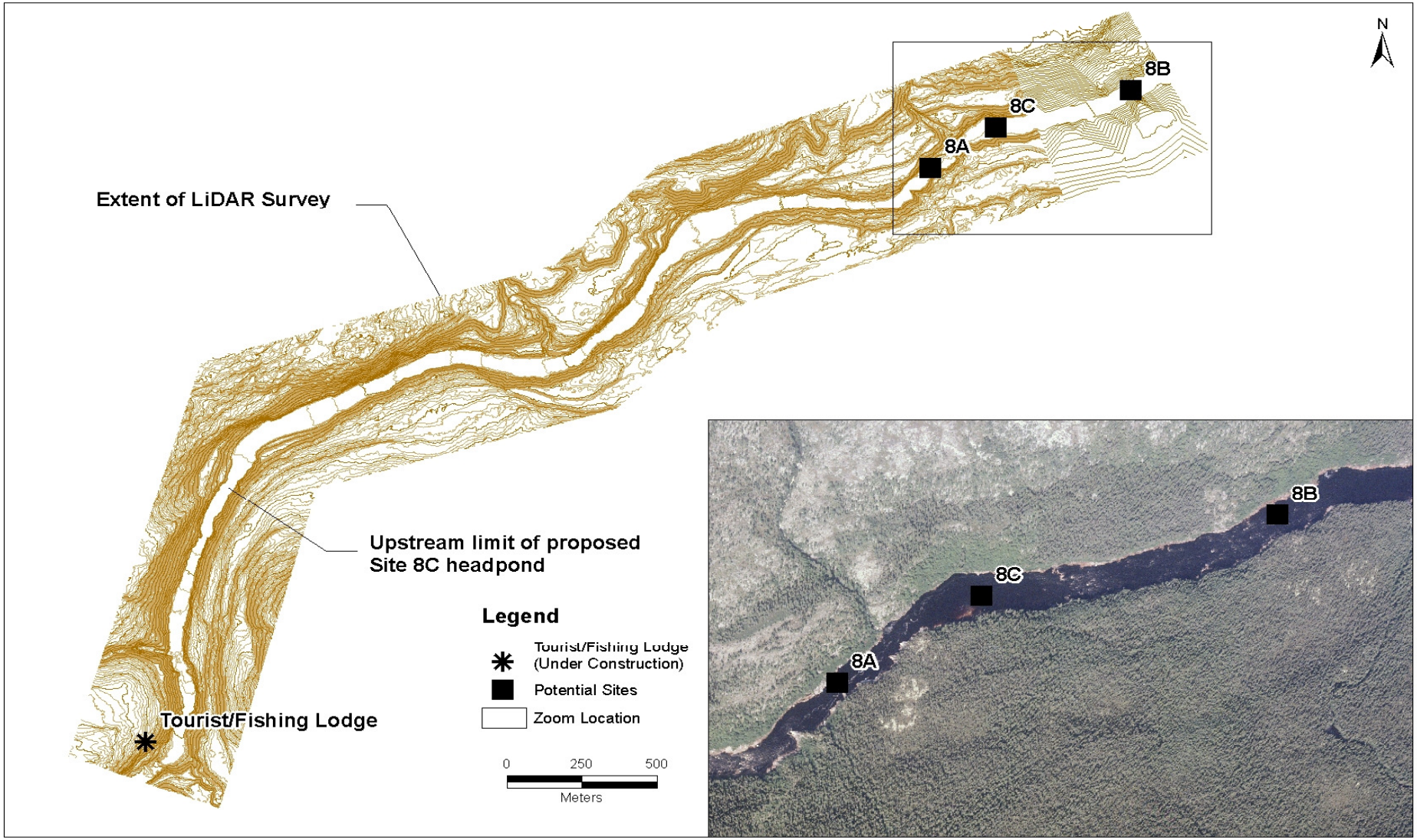


Figure 2-4
Site 8A, Site 8B, and Site 8C Locations
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro

3. Mapping and Site Reconnaissance

3.1 Mapping

The mapping information collected for use in Phase 2 of this study consists of Light Detection and Ranging [LiDAR] airborne surveys, in addition to the collection of high resolution orthomosaic images, at each of the four selected sites. A description of each of these items is presented in the following sections.

3.1.1 LiDAR Survey

LiDAR technology enables the collection of topographic information using a laser system that is affixed to the underside of an aircraft. The laser system, when used in conjunction with Geographical Positioning System (GPS) and Inertial Measurement Unit (IMU) technology, captures a high density of discrete 3D points (up to 500,000 per second) to develop a three dimensional topographical representation of the earth's surface.

LiDAR penetrates through most vegetation types and provides a means to collect accurate bare earth terrain models of large coverage areas, with vertical accuracies of up to 5 cm, without the requirement of traditional survey methods.

XEOS Imaging was engaged by Hatch to conduct LiDAR surveys at each site. Hatch was provided with the following information for each of the top four sites:

- Detailed contours with an interval of 1 m and a vertical accuracy of 0.5 m
- An ArcGrid Digital Terrain Model (DTM) of each site with 0.5 m x 0.5 m resolution

Figures 3-1 through 3-4 show the LiDAR DTM of each of the four sites. Additionally, Figures 3-5 through 3-8 show the contours which were derived from each DTM. The figures illustrate the extent of the LiDAR coverage area for each respective site.

3.1.2 Orthomosaic Imagery

An orthomosaic image, or orthophoto, is collected from an aircraft in much the same way as the LiDAR survey discussed above. Orthophotos are geo-positioned and geometrically corrected (orthorectified) for topographic relief, lens distortion, and camera tilt, such that they can be used to measure true distances in GIS and CAD. The end product can therefore be considered an accurate representation of the earth's surface.

XEOS Imaging was engaged by Hatch to collect high resolution orthophotos of each of the four sites with coverage areas consistent with that of the LiDAR survey.

Figures 3-9 through 3-12 show the orthomosaic image captured for each of the four sites.

3.1.3 Additional GPS Measurements

Additional spot elevations were measured during the Phase 2 site visit using a Differential Global Positioning System (DGPS) system. Measurements were recorded in the forward bubble area of the helicopter using the handheld GPS receiver. The measurements confirmed the existing natural head and tailwater elevations at each site.

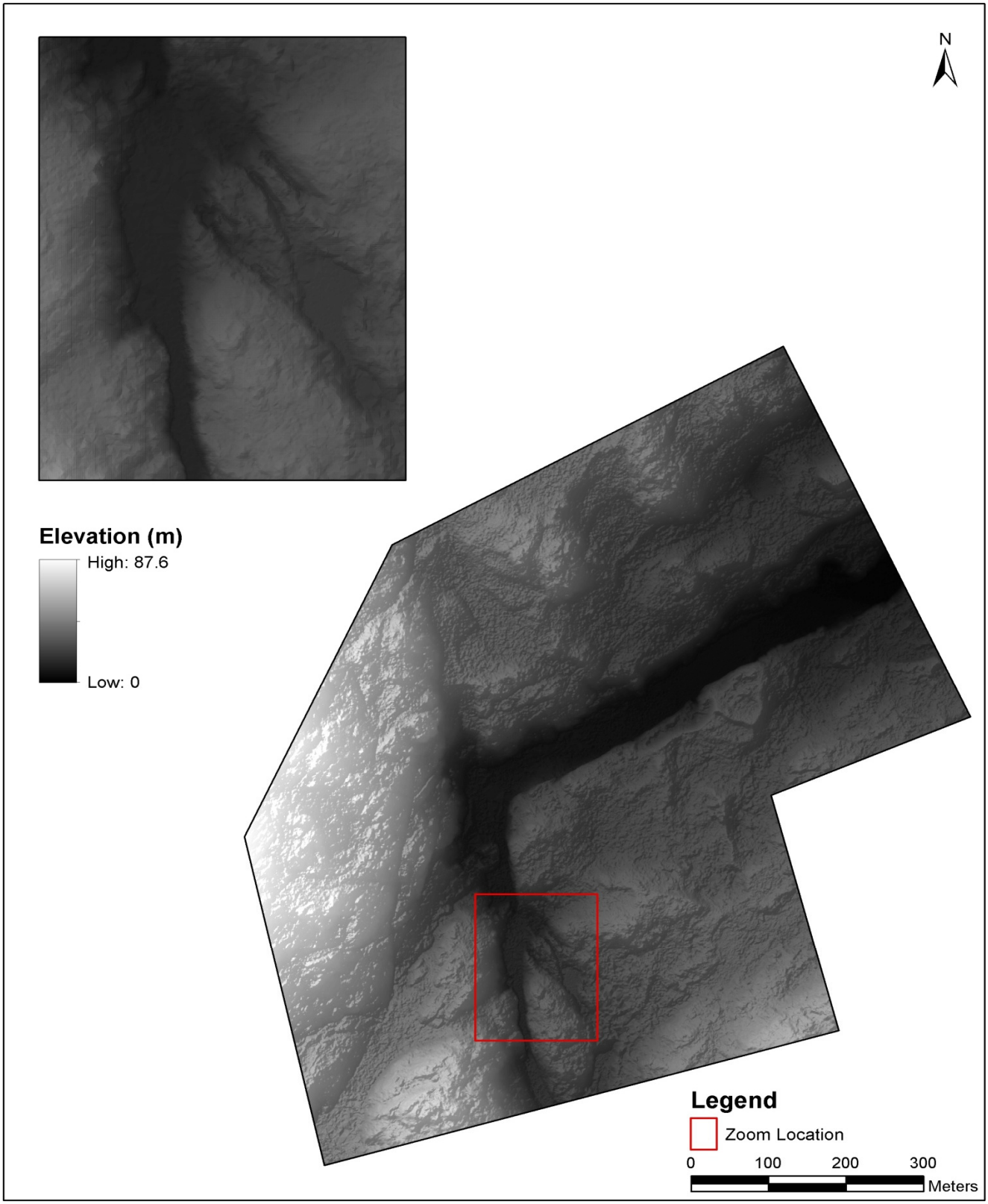


Figure 3-1
Site 11 Digital Terrain Model
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro

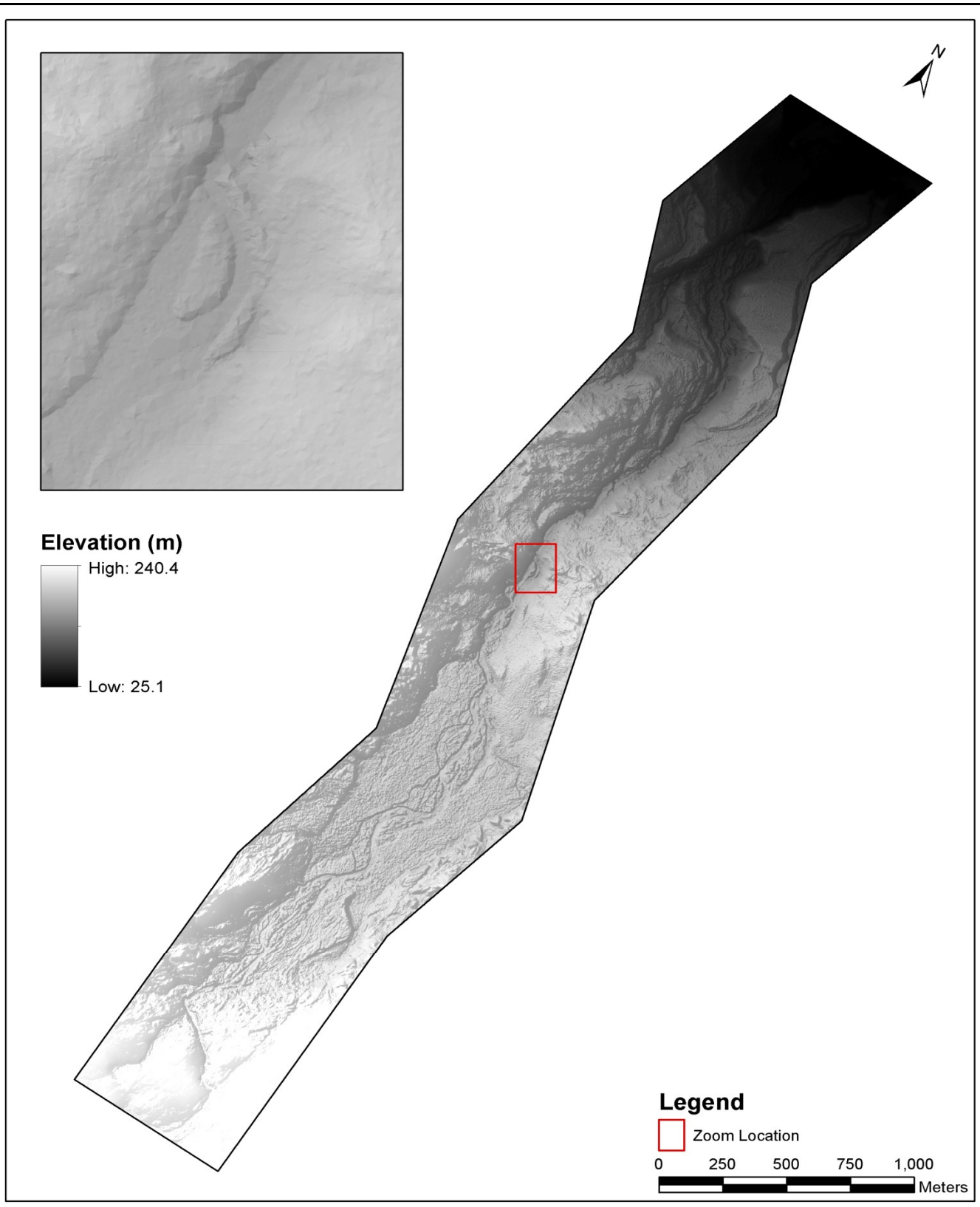


Figure 3-2
Site MK S-2 Digital Terrain Model
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro

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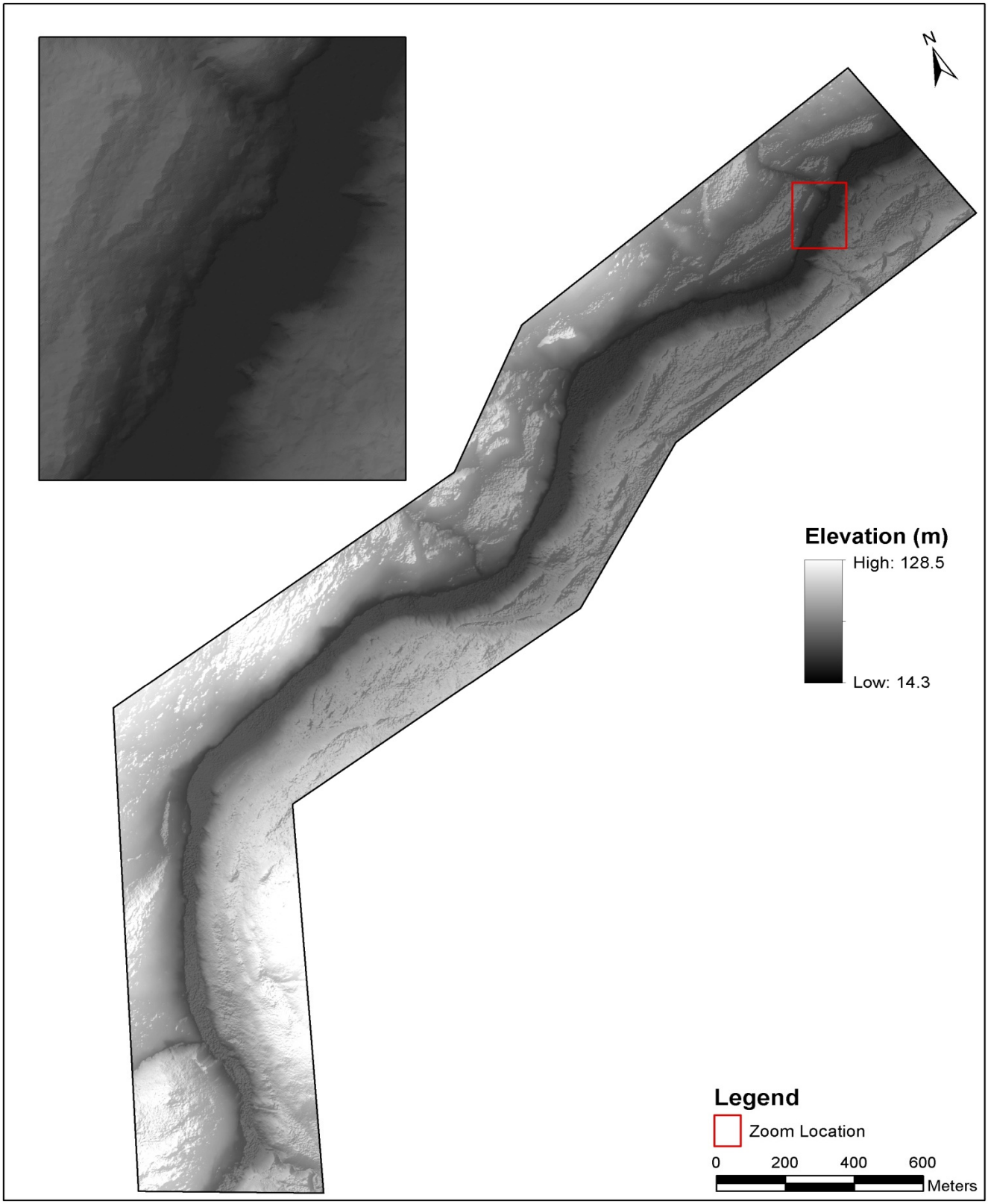


Figure 3-3
Site 8 Digital Terrain Model
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro

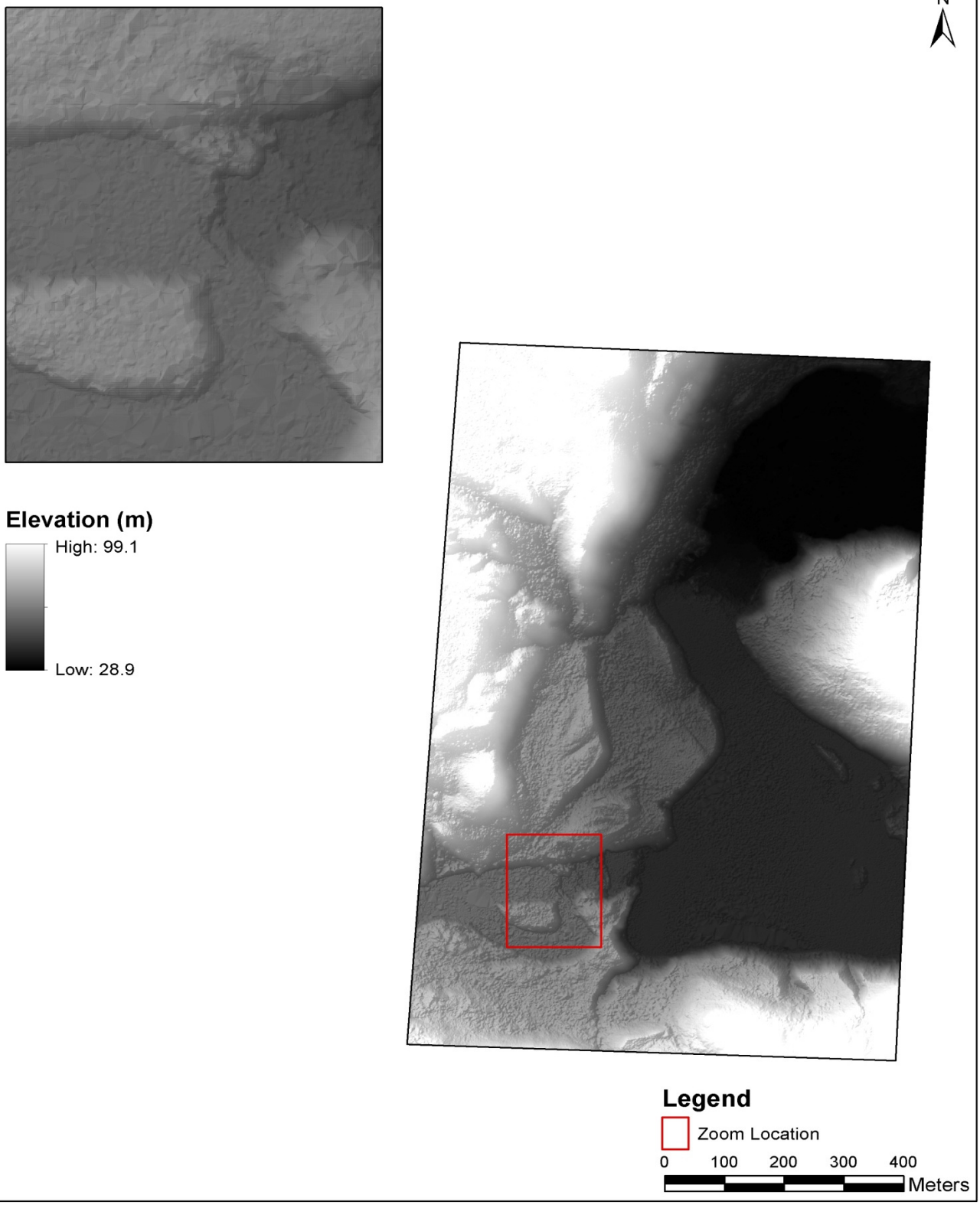


Figure 3-4
Site ALX Digital Terrain Model
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro

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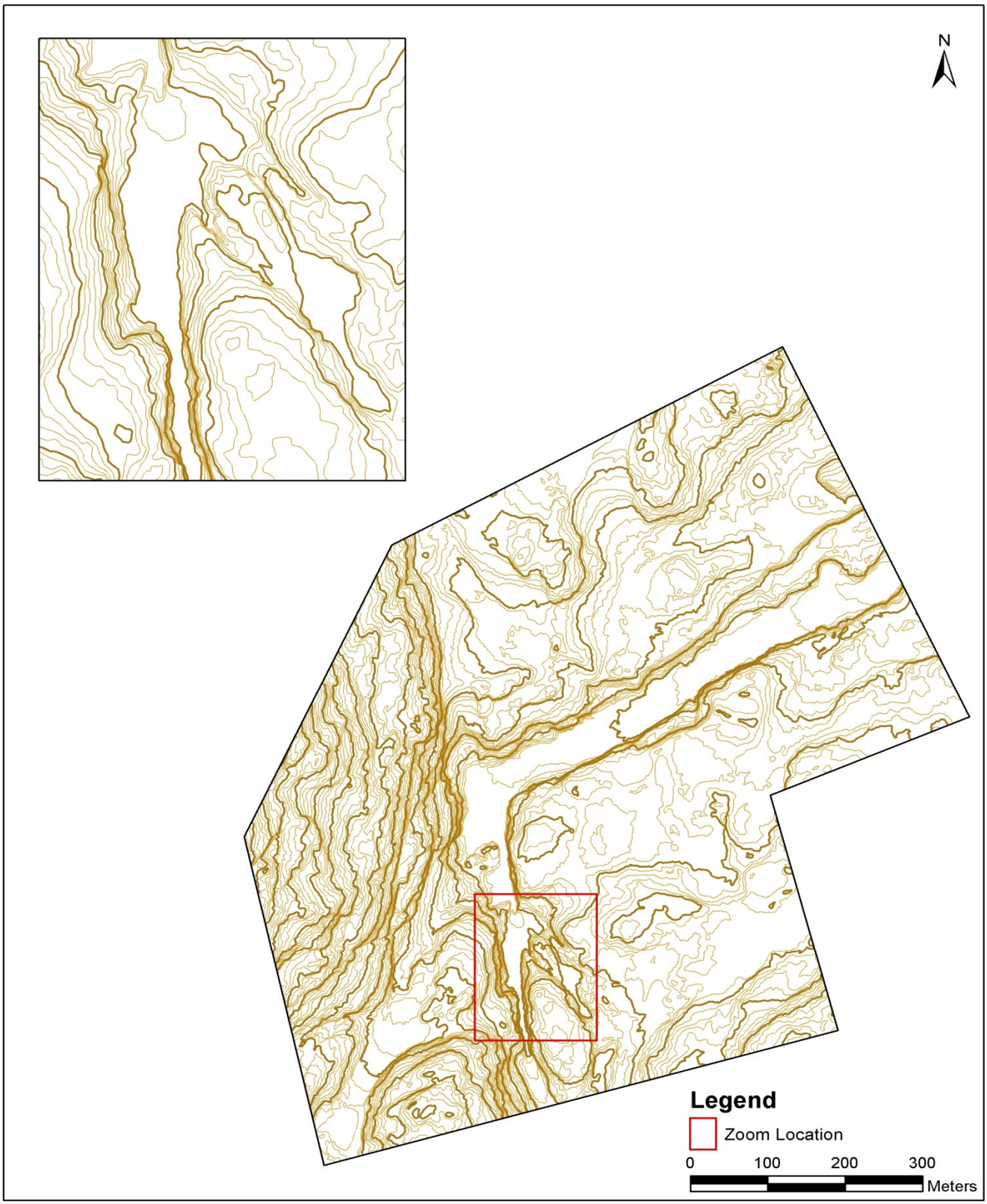


Figure 3-5
Site 11 Contours
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro

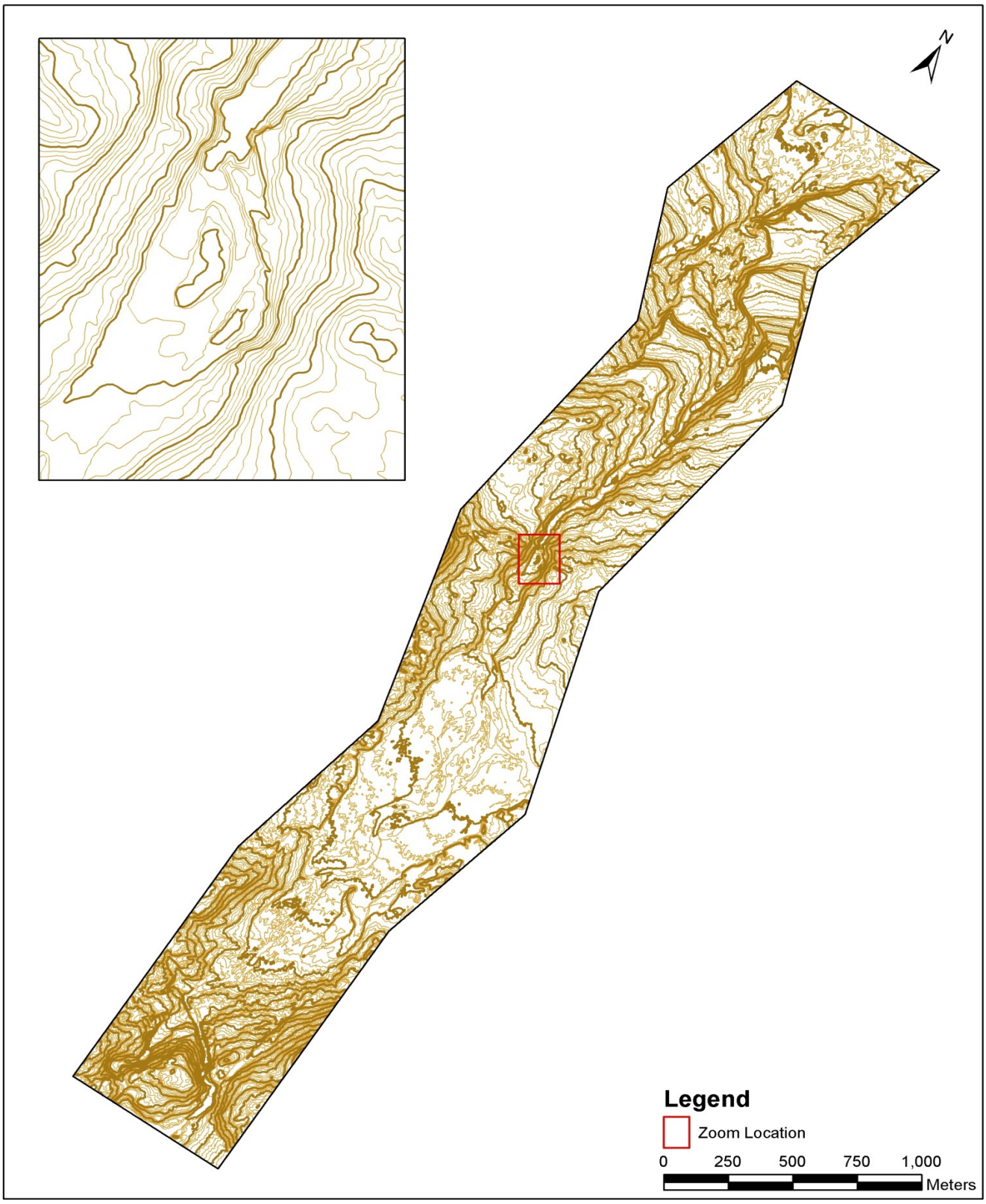


Figure 3-6
Site MK S-2 Contours
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro

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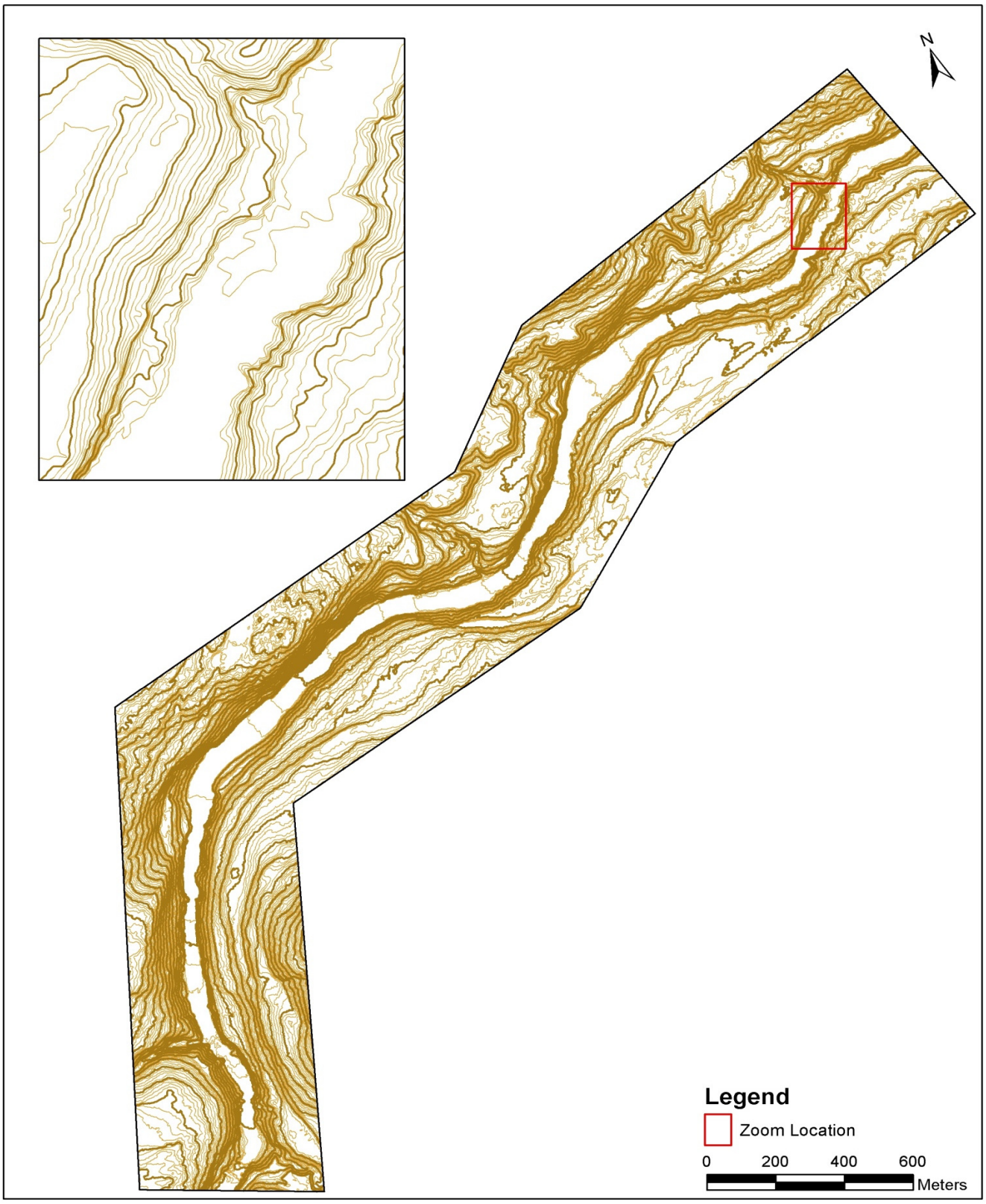


Figure 3-7
Site 8 Contours
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro

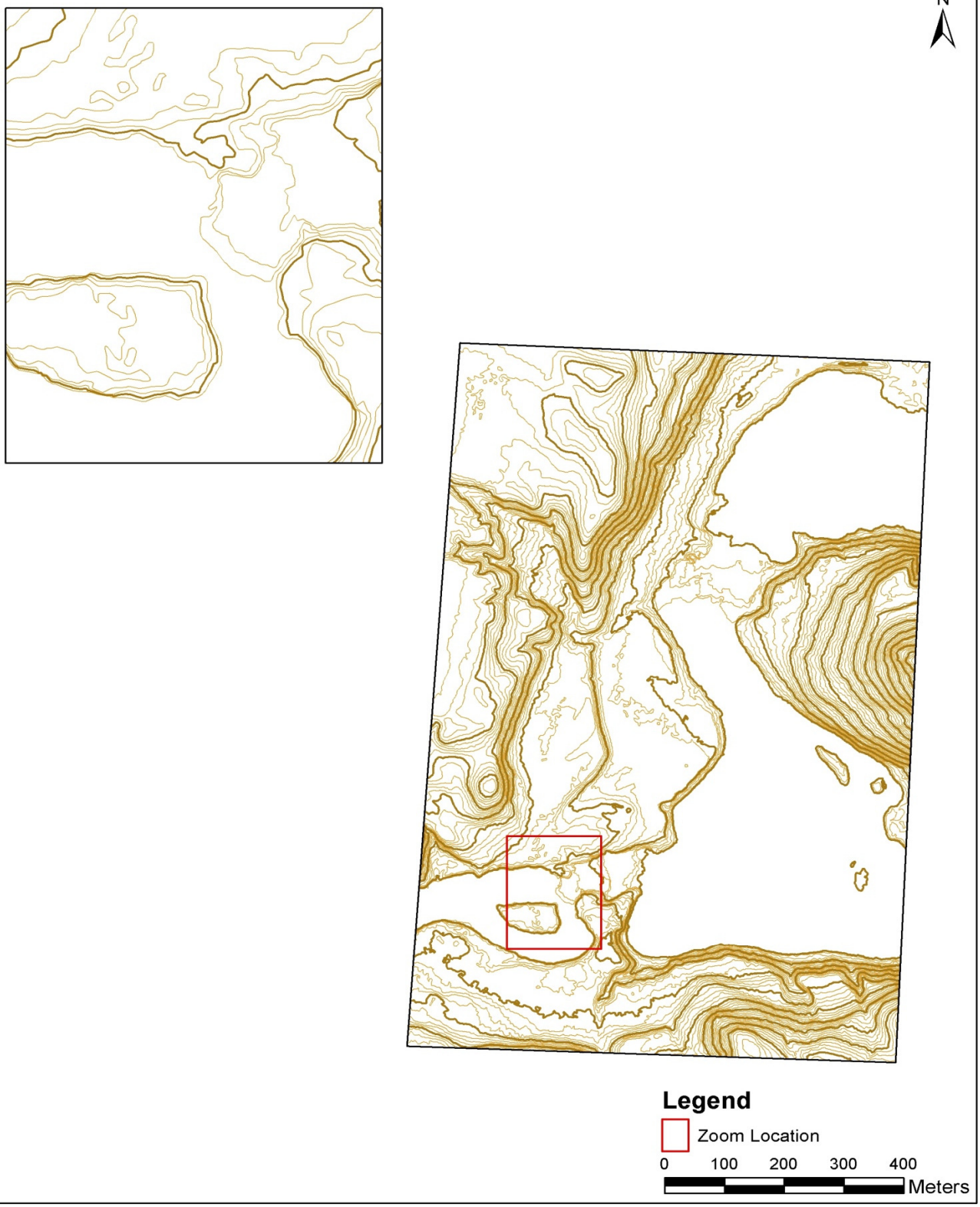


Figure 3-8
Site ALX Contours
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro

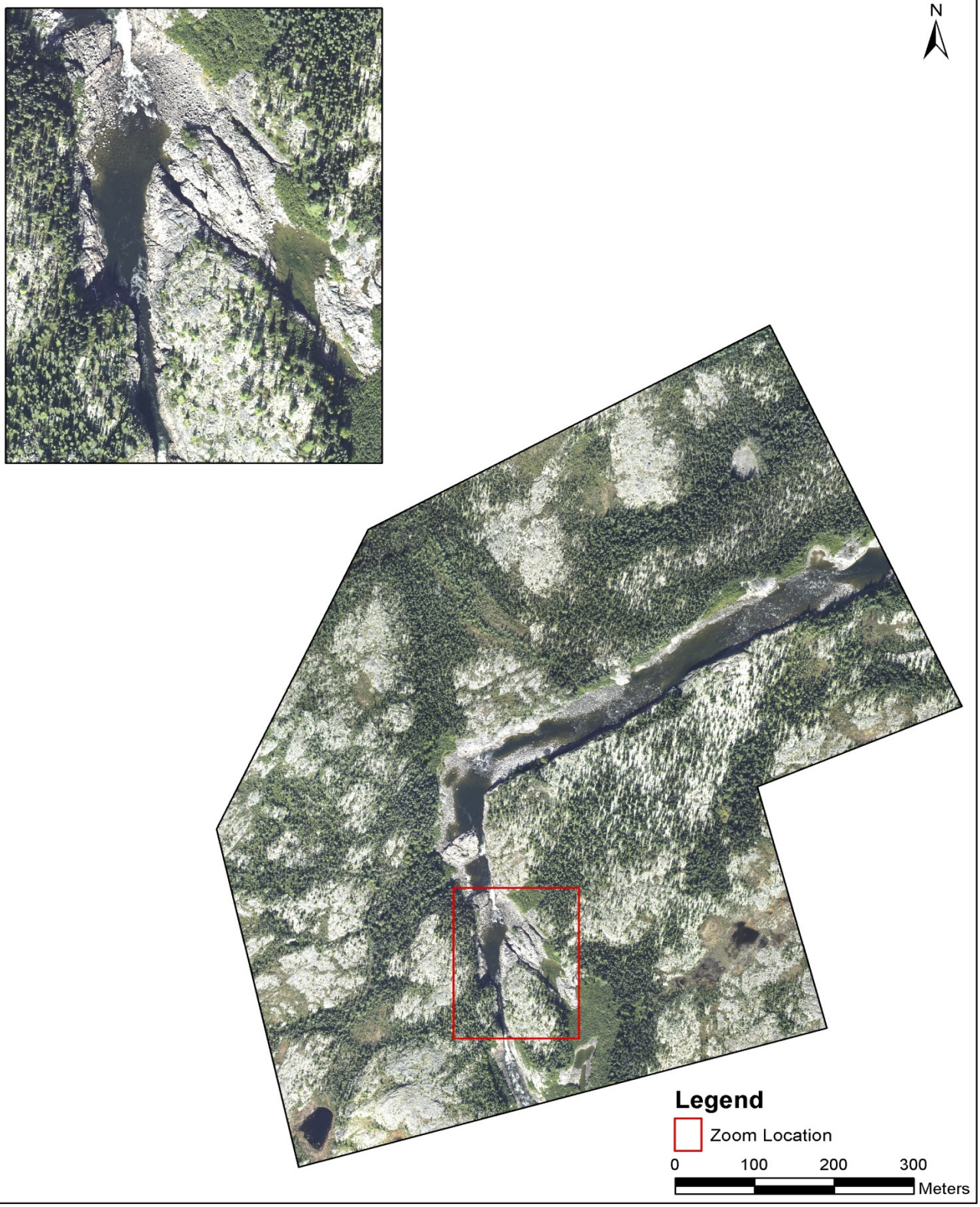


Figure 3-9
Site 11 Orthomosaic Image
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro



Figure 3-10
Site MK S-2 Orthomosaic Image
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro

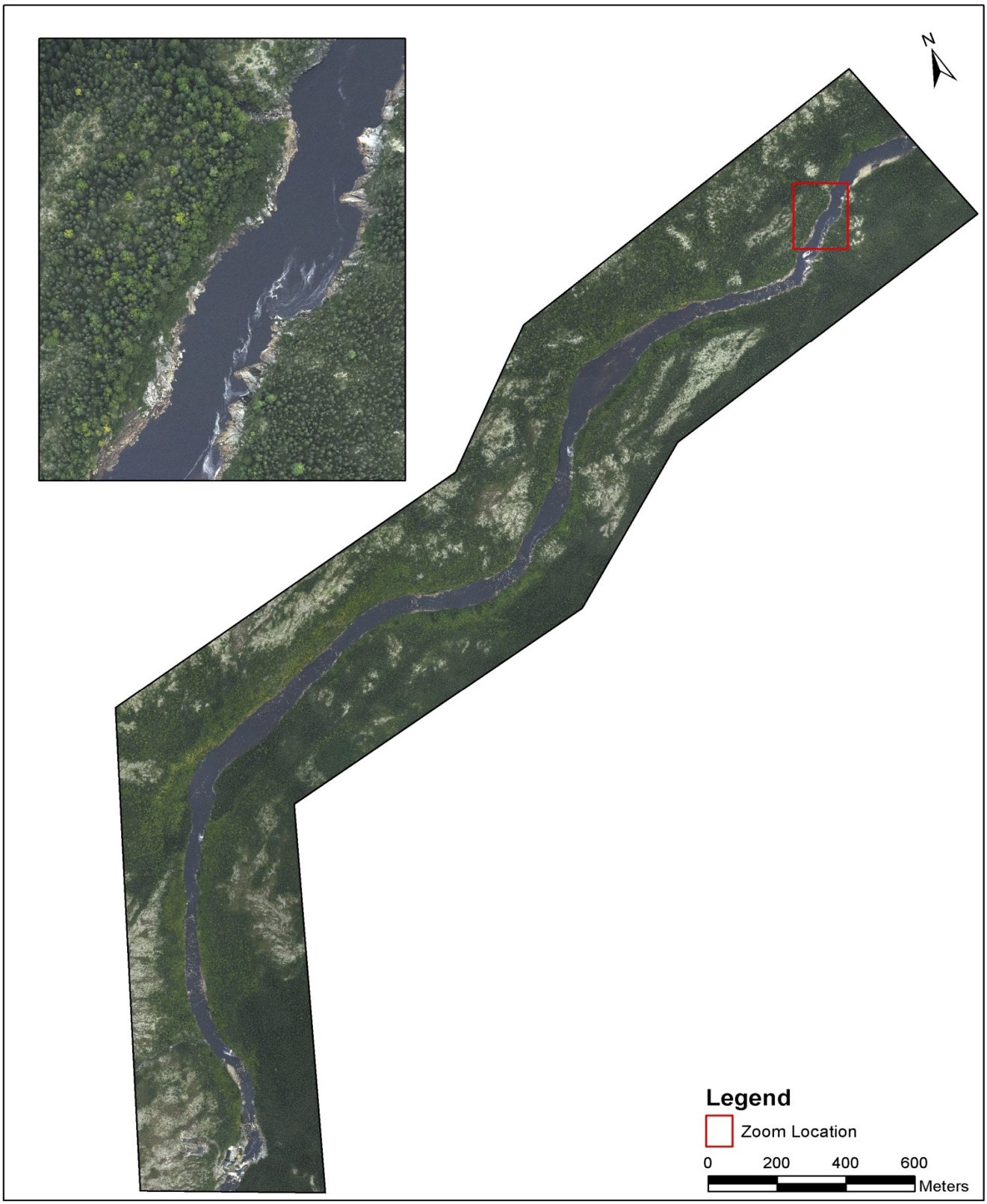


Figure 3-11
Site 8 Orthomosaic Image
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro



Figure 3-12
Site ALX Orthomosaic Image
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro

With the exception of Makkovik, the elevations were measured without topographic control. Site MK S-2 was measured with reference to a geodetic benchmark in Makkovik Harbour. A control point was established at the headwaters of Makkovik Brook at the future location of the flow gauge.

Table 3-1 summarizes the data collected for each site and Figures 1 to 5 in the Phase 2 Site Visit Report (found in Appendix B) indicate the locations of the survey points in relation to geographic features.

Table 3-1: Spot Elevations Measured During Phase 2 Site Visit

Development	Upstream Elevation (m)	Downstream Elevation (m)	Existing Head (m)
Site 11	7.36	-0.29	7.65
Site MK S-2	104.43	24.42	80.01
Site ALX	23.45	14.46	8.99
Site 8A	40.48	17.17	23.31
Site 8B	40.48	13.79	26.69

It should be noted that Site 8C was selected after the Phase 2 site visit, upon receipt and review of the LiDAR survey information. As such, no spot elevations were taken at this location.

3.2 Site Reconnaissance

Phase 2 site visits and helicopter surveys were carried out between September 17 to 20, 2012, to six potential hydro sites by personnel from Hatch and Sikumiut (environmental subcontractor of Hatch). The site visits were part of the Phase 2 work for the four preferred sites selected in the Phase 1 advanced screening, and included return visits to Sites 4 and 5.

The personnel on the site visits were:

Stefan Cahill – Sikumiut Geomatics Technician

David Besaw – Hatch Senior Geologist

John Davies – Hatch Civil Engineer

Murray McFarlane – Hatch Project Manager

A meeting requested by the Town of Charlottetown with representatives of the Town and Hatch was held on September 20, 2012. The intention of the meeting was to provide an overview of the Coastal Labrador energy studies and the Coastal Labrador Hydro feasibility study in particular to the town officials and to answer any questions.

The site visit report documenting the work executed, the results of the visits, minutes of the Charlottetown meeting, and photos, is provided in Appendix B.

4. Hydrology

4.1 Hydrological Regime in Labrador

Evaluation of the economic viability of a hydropower resource at a feasibility level requires estimates of hydrologic design parameters, energy yield and reliability. Where hydrologic records are inadequate or nonexistent, streamflow modeling is an important tool in planning and operational analysis. Hydrologic data in Coastal Labrador are sparse, and final design inputs will depend on the acquisition of at-site data through the planned hydrometric program. In the meantime, the feasibility hydrologic analysis must rely on synthetic records of streamflows, using the best data now available, along with considerable hydrologic judgment.

The mean annual precipitation along Coastal Labrador is higher in the south and lower in the north. Monthly distribution is fairly uniform but the form (rain or snow) depends on temperature. Mean monthly temperatures are above zero generally during May through October, and subzero between November to April. The temperature regime has a very significant influence on streamflows in Labrador. The annual peak flow invariably occurs during the spring due to temperatures rising above zero and consequent snowmelt. Lake evaporation occurs in measurable amounts in June through September, but is negligible or zero for the rest of the year. Increases in streamflow during midwinter are rare due to lack of significant mild spells or rainfall during this time and due to the water holding capacity of the snowpack. Low flows persist throughout the winter and precede the start of the spring flood.

Snow cover is a very important hydrological feature in Labrador. Water stored as snow cover is released when temperatures rise above zero, and is responsible for the high flows experienced in the spring throughout Labrador. Along Coastal Labrador, snow cover is typically present November to April in the south, and October to May in the north.

Naturally flowing rivers in Labrador enter the recession phase when air temperatures drop below zero and a permanent snow cover is established. Typically, the hydrographs are in recession for the winter months of December through April. Low flows persist throughout these months and increase dramatically with the spring flood in May or June. The spring flood accounts for a large portion of the annual runoff. This is due to the melting of the previous winter's accumulation of snowfall. After the spring flood, streamflows gradually decline until August or September, and are then fairly uniform for most of the remainder of the year, at some level between spring flood flows and winter low flows. Lesser runoff peaks from rainfall events may be evident throughout the summer and fall, until November or December when streamflows return to baseflow recession.

4.2 Development of Long Term Inflow Sequences

The hydrological analysis carried out for Phase I of this study was carried forward for use in Phase 2. The at-site flow duration curves developed in Phase I were used to generate a long term daily flow synthesis for use in the power and energy studies. The details of this analysis, as it relates to the top four sites, is outlined below.

4.2.1 Flow Duration Curves

A regional flow duration curve (FDC) methodology was selected as the best approach to synthesize the long term hydrology at the selected, ungauged hydro sites. An FDC is an exceedance probability discharge curve which shows the percentage of time a particular flow is equaled or exceeded. Studies have shown that regional FDC methods can generate curves that very closely resemble observed FDCs at gauges in the same hydrologically homogeneous region.

The approach was to construct FDCs from daily streamflow records of existing hydrometric gauges in the region, relate them to physiographic descriptors of their respective draining basins, and thereby synthesize FDCs for the ungauged potential hydro sites. Figure 4-1 shows the location of each of the top four sites and their respective drainage basins.

A total of 39 hydrometric gauges were selected based on the following criteria:

- Located within Labrador or lower north shore of Quebec
- At least 8 complete years of record
- Drainage area smaller than 20,000 km^2
- Non-regulated (natural) flows

Some gauges had incomplete years of record. Where the data gaps were minor, they were filled by correlation with other gauges, thereby extending the useable number of years. The list of selected gauges and a map of their location is provided in Figure C-1 and Table C-2 of Appendix C.

The FDC of each gauge was nondimensionalized and normalized with respect to mean annual flow (MAF) by dividing each observation by the MAF of the gauge. Normalized flow quantiles Qp were then extracted for 15 probabilities (p in percent) spanning high flows (Q0.1, Q1, Q5, Q10), medium flows (Q15, Q25, Q30, Q40, Q50), and low flows (Q60, Q70, Q80, 90, Q95, Q99).

To predict the FDC for the potential hydro sites it was necessary to relate the physical properties of the basins to parameters of a mathematical function which describes each flow quantile. The usual mathematical model for expressing flow as a function of physiographic data is:

$$Q_p = a \times (Var1)^b \times (Var2)^c \times (Var3)^d \times \ldots$$

Where,

Qp = the flow quantile of interest (normalized to MAF)

a, b, c, etc. = coefficients which must be solved by multiple linear regression

Var1, Var2, etc. = the physiographic descriptors

To carry out a multiple linear regression, the equation is log-transformed, yielding

$$Ln(Q_p) = Ln(a) + b \times Ln(Var1) + c \times Ln(Var2) + d \times Ln(Var3) + \ldots$$

ArcGIS geographic information system (GIS) was used to extract several physiographic descriptors from 1:250,000 digital scale mapping available from the National Topographic Data Base (NTDB) of Canada. The physiographic descriptors that were included in the regression are provided in Tables C-3 and C-4 of Appendix C. A step-wise regression analysis was used to automatically select physiographic descriptors that are effective at predicting the flow quantiles. This method ensures the physiographic descriptors selected for each model are truly independent (not highly correlated with each other). The selected physiographic descriptors were used to execute a linear regression, using the flow quantiles as the response (dependent) variable and the physiographic descriptors as the predictor (independent) variables. The result was a series of 15 prediction equations relating the quantiles to various physiographic parameters. These equations are provided in Table C-5 of Appendix C.

Thus, for the four sites of interest, the quantiles can be calculated by inputting the physiographic parameters, and the normalized FDC for the site can be constructed. As a check on the reliability of the equations, predicted FDCs were constructed for each of the gauge sites and compared to the observed FDCs. As an independent validation, predicted FDCs were also compared to observe FDCs for three other gauges that had not been included in the original regression. The predicted and observed FDCs are provided in Figure C-6 of Appendix C. In general, the agreement is quite good, especially in the medium and low flow ranges which are of primary interest for power and energy generation.

The normalized FDC quantiles were then calculated for the potential hydro sites by inputting their specific physiographic descriptors into the prediction equations. To translate the resulting non-dimensional curves to actual flows, the normalized FDCs for each site had to be multiplied by the respective mean annual flow (MAF) for each site. MAF was calculated from independent estimates of site mean annual runoff (MAR) multiplied by drainage area. MAR was estimated independently for each site using annual streamflows from nearby gauges. MAR was found to be homogeneous between most sites at approximately 700 mm, except for the southernmost sites where MAR was found to increase with proximity to the Strait of Belle Isle; GIS was used to plot isolines and assist in estimating MAR for the hydro sites in this area.

Site 11 is situated approximately 20 km downstream of a natural diversion in the Adlatok River. For this reason, the inflow at Site 11 has two components: 1) inflow from upstream of the diversion, and 2) local inflow from downstream of the diversion. In the absence of at-site flow measurements, an assumption was made regarding how much flow from the upstream basin would continue down the north diversion branch of the river on which Site 11 is located. For the purpose of FDC development, it was assumed that the MAF at Site 11 is equal to half

of the MAF of the upstream basin plus the MAF of the downstream basin. This assumption is illustrated in Figure C-7 of Appendix C.

It should be noted that for Site ALX, the regional methodology was not used since a hydrometric gauge currently exists very near the site location. The Alexis River gauge near Port Hope Simpson (03QC002) has 33 years of record and, as such, a flow duration curve was developed based solely on that data for Site ALX.

The normalized site FDCs are provided in Figure C-8 of Appendix C, and the final FDCs for the top four sites are outlined below in Table 4-1.

Table 4-1: Site Flow Duration Curve Summary

Site	8 (m^3/s)	11 (m^3/s)	MK S-2 (m^3/s)	ALX (m^3/s)
Q0.1	597	1005	23.3	622
Q1	399	811	15.0	418
Q5	235	494	8.02	223
Q10	148	299	5.30	134
Q15	106	218	3.66	90.3
Q20	87.3	182	2.72	71.4
Q25	68.4	146	1.77	52.5
Q30	57.3	124	1.42	43.1
Q40	43.6	99.5	0.991	31.1
Q50	32.6	67.5	0.472	22.6
Q60	23.1	45.0	0.284	16.7
Q70	16.7	32.6	0.154	12.0
Q80	11.8	25.2	0.093	8.70
Q90	7.99	16.7	0.077	6.27
Q95	6.55	12.7	0.061	5.09
Q99	4.86	7.88	0.028	3.85
DA (km^2)	**2403**	**5623**	**73.8**	**2312**
MAF (m^3/s)	**61.0**	**125**	**1.64**	**52.0**
MAR (mm)	**800**	**700**	**700**	**710**



Figure 4-1
Site Drainage Basins
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro

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4.2.2 Synthetic Inflow Sequences

Synthetic daily inflow sequences were developed at Sites 8, 11 and MK S-2 using the predicted FDCs, as outlined in Table 4-1, and the historical daily flow series at a selected index gauge. The time series of flows at the ungauged sites were derived by assuming that the same probability of occurrence of daily flows can be expected at the ungauged and index locations.

Two index gauges were selected, one in the north and one in the south, each with greater than 30 years of historical daily flow record. The hydrometric gauge located on the Ugjoktok River below Harp Lake (03NF001) has a period of record ranging from 1970 to 2010 and was adopted as the index gauge for Site MKS-2 and Site 11. The Alexis River gauge near Port Hope Simpson (03QC002) has a period of record ranging from 1978 to 2011 and was selected as the index gauge for use at Site 8. Since the at-site daily FDC for each gauge was considered to be adequately represented by the FDC calculated at each index gauge location, (see Section 4.2.1), it can be concluded that the two selected gauges are hydrologically representative of the region.

As noted in Section 4.2.1, the Alexis River gauge near Port Hope Simpson (03QC002) is located very near Site ALX. Because of the sites proximity to the gauge, the historical daily flow sequence at this gauge was adopted for Site ALX and the methodology outlined above was not used.

The synthesized long term daily inflow sequences and associated mass plots for each of the top four sites are respectively provided in Figures C-9 and C-10 of Appendix C. Additionally, Table C-11 provides the synthesized average monthly flows for each site.

4.3 Flood Hydrology

The spillway capacities at the four preferred sites were determined from the estimate of the Inflow Design Flood (IDF) at each of the sites. The analysis carried out in Phase 1 was carried forward for use in Phase 2 and its associated methodology, as it relates to the top four sites, is described below.

A regional approach was required due to the sparseness of flood data near the potential project sites. The method of direct regression for flood quantiles was employed, using GIS techniques which enabled physiographic variables to be efficiently abstracted from topographic data. The following steps were included in the approach:

(i) carry out frequency analysis of floods at existing hydrometric gauges in the region;

(ii) relate the floods to physiographic descriptors of the respective drainage basins, in order to develop regional prediction equations for the flood return periods of interest; and

(iii) apply the equations to predict flood estimates for the ungauged potential hydro sites.

Initially, the data base for single station flood frequency analysis consisted of all flood data for the 39 gauged watersheds in Labrador and nearby areas in Quebec. Among these 39 gauges, 31 gauges had 10 or more observations of annual maximum daily flow and were selected for data screening and frequency analysis. Only 15 of the gauges had any observations of annual maximum instantaneous (peak) discharge. Owing to the relative scarcity of peak flow data, it was felt that the 31 series of maximum daily data would result in more reliable estimates, which may subsequently be converted to peak flows by applying suitable peaking factors. The 31 watersheds that were considered for at-site frequency analysis are listed in Table C-12 of Appendix C.

Before proceeding with the frequency analysis, each data series was screened for serial independence, homogeneity, and absence of trend. The Hyfran computer program was used for conducting the single station frequency analyses. The two-parameter lognormal (LN) distribution was selected as the most appropriate for the region. This distribution was used to predict the flood magnitudes for various return periods at each station. The estimated flow rates for the 5, 10, 25, 100 and 1000-year return period for all the gauges are provided in Table C-13 of Appendix C.

Using multiple linear regressions, equations were developed for the study region which provided predictions of flood magnitudes with 5, 10, 25, 100 and 1000-yr return period based on physiographic data, in the following form:

$$Q_T = a \times (Var1)^b \times (Var2)^c \times (Var3)^d \times \dots$$

Where Q_T is the flood magnitude with return period T; a, b, c, d,... are equation constants, and $Var1$, $Var2$, $Var3$,... are equation variables which are the significant physiographic parameters.

The above equation can be transformed to a linear equation by taking the natural logarithm of both sides of the equation, so that that the multiple linear regression can be performed. The final form of the equation is as follows:

$$Ln(Q_T) = Ln(a) + b \times Ln(Var1) + c \times Ln(Var2) + d \times Ln(Var3) + \cdots$$

A stepwise regression was performed between flood magnitudes as dependent variables at different gauging stations, and their respective physiographic parameters as independent variables. The same physiographic parameters as in Section 4.2.1 were tested for the flood regression.

The significant parameters in both regression equations were drainage area (DA), barren area (AB) as a fraction of DA, latitude of the centroid of the drainage area (LAT), and finally the total area of lakes in the watershed (AL) as a fraction of DA.

The result was a set of five prediction equations (one equation per return period) relating the flows to the physiographic parameters. The final regression equations are provided in Table C-14 of Appendix C. Thus, for any site of interest, the floods can be calculated by inputting the physiographic parameters.

As a check on the reliability of the equations, flood predictions using the equations were compared to the estimates obtained by direct frequency analysis at the individual gauges. Table C-15 of Appendix C provides the results of this comparison. In general, agreement was reasonable for this level of study with accuracies ranging from 15% to 19%.

The regression equations were subsequently applied to the four hydro sites and Table 4-2 provides the estimates of flood magnitudes with 5, 10, 25, 100 and 1000-yr return periods.

Table 4-2: Summary of Flood Estimates

Site		5-yr (m^3/s)	10-yr (m^3/s)	25-yr (m^3/s)	100-yr (m^3/s)	1000-yr (m^3/s)
Hopedale	11	908	934	1062	1149	1439
Makkovik	MK S-2	31.5	33.8	40.0	45.5	61.1
CHT/PHS/MSH	8	667	708	830	932	1229
	ALX	683	789	922	1115	1432

Site 11 is situated downstream of a natural diversion on the Adlatok River. For the purpose of determining flood estimates, the inflow at Site 11 is assumed to be comprised of half of the flow from upstream of the diversion plus the local inflow downstream of the diversion.

As noted in Section 4.2.1, the Alexis River gauge near Port Hope Simpson (03QC002) is located very near Site ALX. As such, the at site flood frequency analysis at this gauge was adopted for estimating flood magnitudes at Site ALX and the regional methodology outlined above was not used. The frequency plot for Site ALX is outlined in Figure C-16 of Appendix C.

A review of the available flood peak data failed to establish any meaningful relationship between maximum instantaneous (peak) and maximum daily flow or drainage area size. For 12 of the 15 gauges with annual peak flow records, the highest observed peaking factors (ratio of peak to daily flow) were between 1.0 and 1.1. This is within the level of uncertainty for the daily flood estimates, and it is recommended that estimation of peaking factors for flood design be carried out after data is collected from the at-site hydrometric program.

4.4 Dam Classification and IDF Selection

4.4.1 Guideline Review

The Canadian Dam Association (CDA) Guidelines are an accepted industry dam safety standard and have been consistently used by Newfoundland and Labrador Hydro for decades. Because of this practice, the CDA Guidelines were adopted for use in this study for dam classification and selection of Inflow Design Flood (IDF) at the respective hydro sites.

The CDA Guidelines present a classification scheme, provided in Table 4-3, which is used to determine the suggested design flood for a structure. Estimates of potential consequences of dam failure are categorized to distinguish dams where the risk is much higher than others. The dam classification is determined by the highest potential consequence, whether loss of life, environmental, cultural, or economic losses.

Table 4-3: 2007 CDA Dam Classification Scheme

Dam Class	Population at Risk	Incremental Losses		
		Loss of Life	Environmental and Cultural Values	Infrastructure and Economics
Low	None	0	Minimal short-term loss No long-term loss	Low economic losses; area contains limited infrastructure of services
Significant	Temporary Only	Unspecified	No significant loss or deterioration of fish or wildlife habitat Loss of marginal habitat only Restoration or compensation in kind highly possible	Losses to recreational facilities, seasonal workplaces, and infrequently used transportation routes
High	Permanent	10 of fewer	Significant loss or deterioration of important fish or wildlife habitat Restoration or compensation in kind highly possible	High economic losses affecting infrastructure, public transportation, and commercial facilities
Very High	Permanent	100 or fewer	Significant loss or deterioration of critical fish or wildlife habitat Restoration or compensation in kind possible but impractical	Very high economic losses affecting important infrastructure or services (e.g., highway, industrial facility, storage facilities for dangerous substances)
Extreme	Permanent	More than 100	Major loss of critical fish or wildlife habitat Restoration or compensation in kind impossible	Extreme losses affecting critical infrastructure or services (e.g., hospital, major industrial, complex, major storage facilities for dangerous substances)

The CDA dam classifications shown in Table 4-3 have been subdivided by Population at Risk (PAR). For dams with no permanent population at risk in the dam breach inundation zone, the highest the dam class could be, based on loss of life, is "SIGNIFICANT". For dams with a permanent population at risk in the breach inundation zone, the range of dam classifications is "HIGH" to "EXTREME" depending on the severity of flooding. The governing factor in this case is the potential for loss of life; 10 or fewer for "HIGH", 100 or fewer for "VERY HIGH", and more than 100 for "EXTREME".

The CDA dam classification table for environmental and cultural values categorizes the dam class on the loss or deterioration of fish or wildlife habitat and the feasibility of restoration or compensation of losses to habitat or sites of cultural and historic value.

The 2007 CDA Guidelines identify economic losses to include damages to third-party property, facilities, other utilities, and infrastructure. The Guidelines do not however, provide a range or threshold of economic losses corresponding with each of the dam classes. This makes it difficult to determine the dam class based on quantifiable economic losses, and for this reason, other provincial jurisdictions have provided economic losses in relation to defining dam classes. As an example, regulators in both the provinces of British Columbia and Ontario have developed relationships between expected economic losses and dam class. However, the dam classes noted in these regulations do not match exactly with those in the 2007 CDA Guidelines. Hatch has reviewed the CDA Guidelines in conjunction with the British Columbia and Ontario regulations, and has prepared the relationships between economic losses and CDA dam class summarized in Table 4-4.

Table 4-4: Dam Classes and Associated Economic Losses

CDA Dam Class	Economic Damages ($)
"EXTREME"	>100 million
"VERY HIGH"	>10 million
"HIGH"	>1 million
"SIGNIFICANT"	>$100,000
"LOW"	<$100,000

Once the dam classification exercise is complete, IDF selection can be carried out according to the CDA Guidelines. The CDA's suggested design flood criteria, based on dam classification, is outlined in Table 4-5.

Table 4-5: Suggested CDA Design Floods

Dam Classification	IDF AEP
Low	1/100
Significant	Between 1/100 and 1/1000
High	1/3 between 1/1000 and PMF
Very High	2/3 between 1/1000 and PMF
Extreme	PMF

4.4.2 Dam Classification and IDF Selection

Each of the top four sites have been provisionally classified according to the CDA Guidelines and a summary of each is outlined in the following sections. It should be noted that a more detailed dam break exercise would be required, at a later date, to confirm the below assumptions.

Site 11

Site 11 is located approximately 2 km upstream of Adlatok Bay on the Adlatok River and about 45 km southwest of Hopedale. Due to the sites remoteness, it is not expected that there would be any permanent population at risk. The Adlatok River, however, is one of Labrador's premiere salmon angling rivers and is occupied by tourists and anglers during the salmon fishing season which runs from June 15 to September 15 each year. As noted in Section 4.1, the spring runoff in Northern Labrador typically occurs in May or June each year and brings with it high flows which account for a large portion of the annual runoff. Since high inflows, and associated reservoir surcharge, are most often the mechanism causing dam failure, it can be concluded that the system would be most vulnerable during May and June when the spring freshet arrives. Since there is only minimal overlap between the spring runoff window and the salmon fishing season, it is assumed that the probability of anglers being present in the event of a dam breach is very unlikely. Additionally, due to the small headpond size at Site 11, and the fact that the river widens abruptly from less than 100 m to greater than 1000 m into Adlatok Bay, it is expected that potential breach affects would be limited to the 2 km reach immediately downstream of the structure. Site visits revealed that a cabin is situated downstream of Site 11 on the top of the left (north) bank of the river. It is not anticipated that this structure would be within the inundation zone in the event of a dam breach and, as such, it was not included in the loss of life or economic assessment. Although a breach may temporarily affect aquatic and terrestrial species and habitat, it is not expected that the affects would be so widespread so as to have permanent, irreversible affects. The tentative hazard classification of Site 11 would therefore be SIGNIFICANT and the associated IDF is the 100-yr flood (1,149 m^3/s).

Site MK S-2

Site MK S-2 powerhouse is located approximately 6.5 km upstream of Makkovik on Makkovik Brook and the proposed dam is located approximately 2.0 km upstream of Round Pond. Due to the small headpond size at Site MK S-2, the distance to downstream population and the fact that the Makkovik Brook widens abruptly into Makkovik Harbour, it is not expected that there would be enough incremental inundation at the town to warrant risk to a permanent population. Although a breach may temporarily affect aquatic and terrestrial species and habitat, it is not expected that the affects would be so widespread so as to have permanent, irreversible affects. The tentative hazard classification of Site MK S-2 would therefore be SIGNIFICANT and the associated IDF is the 100-yr flood (45.5 m^3/s).

Site 8C

Site 8C is located approximately 8 km from Port Hope Simpson on the St. Lewis River, and approximately 16.5 km upstream of the Trans Labrador Highway (TLH) bridge at Wood Island. The towns of Mary's Harbour and St. Lewis are situated approximately 22 km downstream of the TLH. Due to the relatively small headpond size at Site 8C, the distance to downstream population and the fact that the St. Lewis River widens abruptly from less than 100 m to greater than 1200 m just upstream of the TLH bridge, it is not expected that there would be enough incremental inundation at Mary's Harbour or St. Lewis to warrant risk to a permanent population. Additionally, the water level at the TLH bridge location is not expected to rise enough to jeopardize the structure. If, in the event of a breach, damages were caused to the TLH bridge, the associated rehabilitation costs would likely be less than $1,000,000. Although a breach may temporarily affect aquatic and terrestrial species and habitat, it is not expected that the affects would be so widespread so as to have permanent, irreversible affects. The tentative hazard classification of Site 8C would therefore be SIGNIFICANT and the associated IDF is the100-yr flood (932 m^3/s).

Site ALX

Site ALX is approximately 40 km west and upstream of Port Hope Simpson on the Alexis River. The TLH crosses the Alexis River near Port Hope Simpson, as well. Due to the small headpond size at Site ALX, the distance to downstream population and the fact that the Alexis River gradually widens from approximately 100 m to greater than 1600 m just upstream of Port Hope Simpson, it is not expected that there would be enough incremental inundation at the town to warrant risk to a permanent population. Additionally, the water level at the TLH bridge location is not expected to rise enough to jeopardize the structure. If, in the event of a breach, damages were caused to the TLH bridge, the associated rehabilitation costs would likely be less than $1,000,000. Although a breach may temporarily affect aquatic and terrestrial species and habitat, it is not expected that the affects would be so widespread so as to have permanent, irreversible affects. The tentative hazard classification of Site ALX would therefore be SIGNIFICANT and the associated IDF the 100-yr flood (1,115 m^3/s).

4.5 Hydrometric Data Collection Program

The purpose of the hydrometric data collection program is to acquire reliable flow data at each of the top four sites. The data collected over a three year period will be used, at the end of the collection program, to confirm the economic viability of the sites recommended in the Feasibility Study. Environmental Canada has been engaged to install and monitor these gauges.

Hydrometric gauges were proposed for Sites 8, 11 and MK S-2. A hydrometric gauge already exists very near Site ALX, therefore this eliminates the requirement to install a gauge at this site location.

The hydrometric data collection equipment consists of the following:

- Sutron SatLink 2 Logger c/w GOES RealTime
- Sutron constant flow bubblers
- Antenna c/w cables
- Batteries, Solar Panels, controller etc.
- Miscellaneous Supplies (Pressure lines, antenna masts, etc.)
- Weather proof shelters to house the equipment.

4.5.1 Progress to Date

All hydrometic equipment was purchased and shipped to Environment Canada's Labrador office in August, 2012. The hydrometric gauge shelters and landing pad materials, for Sites 8 and 11, were purchased by Sikumiut and were shipped to the NL Hydro diesel plant at the town nearest each respective hydrometric gauge location in September, 2012.

Permit applications for all sites were submitted to regulatory authorities in August, 2012. Hatch acquired the necessary permits for Site 8 in early October and installation activities commenced shortly thereafter.

The subcontractor, Sikumiut, conducted clearing/cutting, gauge shelter erection and landing pad construction at Site 8 from October 9 to 15, 2012. The team experienced weather delays, and additional time was required to clear the site due to the very dense and high tree cover. Environment Canada subsequently installed the hydrometric gauge and associated equipment at Site 8 during the week of October 15, 2012. Photographs of the newly installed Site 8 gauge and the existing Alexis River gauge are provided in Photo Log C-17 of Appendix C.

4.5.2 Next Steps

Due to delays with permitting applications on Labrador Inuit Lands, the installation of hydrometric gauges at Site 11 and MK S-2 did not take place in 2012. A meeting has been scheduled with the Nunatsiavut Government (NG) for December 6, 2012, to discuss the

Coastal Labrador energy studies, including the installation of these hydrometric gauges. It has been recommended in Section 12 of this report that the equipment supplied for Site MK S-2 should be installed on a different watercourse, as Site MK S-2 was found to be uneconomical. Further, it has been recommended that the planned installation of the Site 11 gauge could be delayed, as it may be more beneficial if the equipment is located on another river at this time.

The Site 8 hydrometric gauge is equipped with a data logger which enables water level, and flow data once a rating curve has been developed at site, to be viewed by users online in real time (*http://www.env.gov.nl.ca/wrmd/ADRS/v6/Graphs_List.asp*). It is expected that water level information will be available online in the near future.

5. Geotechnical Assessment

5.1 Site 11

5.1.1 Setting

Site 11 is located in an isolated area about 45 km southwest of Hopedale. The general area and the site have been extensively glaciated to bare bedrock.

The flow at Site 11 is dynamic during high water levels. The flow funnels through a chute that drops rapidly in elevation and then turns sharply at right angles.

5.1.2 Soils

The soils are alluvial or glacio-fluvial in nature and occur in several places at this site. Figures 5-1 and 5-2 identify the locations of the alluvial deposits. They are as follows:

- Along both sides of the shoreline in the pond leading to the chute. On the east side and opposite the chute, the deposit is exposed as cobbles and boulders in the pond near the dam centerline (Figure 5-2).
- In an esker deposit that is parallel to the river downstream of the river bend. Some material has been removed from the esker possibly for the cabin development nearby.
- In the forested area downstream of the chute at the elbow in the river, which is a continuation of the jointing structure at the chute, exists a depression in the rock caused by glacially action and suspected infilling with granular material (Figure 5-1).

5.1.3 Bedrock

The regional area is described in the Phase 1 report as Precambrian gneiss which is strongly banded, migmatitic and containing numerous amphibolites inclusions and relic mafic dykes. Regionally, the gneiss is cut by numerous diabase or gabbro dykes.

The on-site observations are somewhat different than what is described above (Figure 5-2). The dam site and spillway are underlain mostly by tight, medium-to-coarse grained, microfractured, pink, strong granite. The granite is gneissic between the faulting along the dam centerline. The gneiss is assumed to contain two faults or shears that is fractured in the area of the powerhouse. Another fault exists to the immediate west of the powerhouse location. The area between the fault traces at the powerhouse is expected to be fractured, strong rock which may contain two 100 mm wide distinct bands comprising broken rock and 25 mm of gouge.

The micro-fracturing is tight and has not led to ice jacking.

The river course is defined by two dominant joint sets. One set parallels the chute dipping at 75° east and the other parallels the other leg of the river dipping at 85° north. These joint sets can have long persistence and have moderate spacing locally, otherwise the jointing is widely spaced.

The chute has developed because of plucking out of the close jointing in this area and not because of faulting. The joint system at the chute continues into the forested area downstream. This area is possibility infilled with granular soil.

5.1.4 Construction Materials

This site has an abundance of granular material. The gradation of this material is not known. The esker is sand and gravel with cobbles. Chances are the finer sands are missing which are generally normal for esker deposits. The alluvium in the pond upstream of the powerhouse is cobbles and small boulders at the surface. Another esker exists just to the west of the dam. It is just outside Figure 5-1. Processing as screening and crushing will be required.

The potential of finding till in this area is low because of the extensive glacial denudation.

As usual in this part of Labrador, rock fill is abundant.

5.1.5 Design Considerations

The bedrock quality will make an excellent foundation for a dam and the island effect at the dam location is ideal for river diversion during construction. The bedrock is tight and not ice-jacked. Grouting of the joint set at the chute and at the sheared area are required. The grouting and takes will not be unusual. The proposed Site 11 dam location is shown in Photo 1, looking upstream.

A fault does not exist in the chute.

5.2 Site MK-S2

5.2.1 Setting

The MK-S2 dam site is located on Makkovik Brook (Photo 2); the powerhouse for this scheme is upstream of Round Pond at a distance of about 6.5 km from the town of Makkovik. The dam structure is situated about 1.5 km upstream of the powerhouse (Photo 2) and the water is conveyed by a long penstock to the powerhouse.

5.2.2 Soils

Two types of soils exist along Makkovic Brook system. They are described generally as glacio-fluvial granular soil and till (Figure 5-3). The locations of these deposits are based on aerial photos examination and a fly over. The ground proofing of these areas is still required.

The glacio-fluvial deposits occur around Round Pond and in the braided stream portions of the brook. Areas of the beaches at Round Pond are sand covered while the braided section of the brook that flows into Round Pound is coarse gravel and cobbles at the surface. It is anticipated the sand portion at the surface in the latter case is washed out. The braided deposit is expected to extend back several hundred meters upstream from Round Pond (Photo 3).

The till deposits occur as linear belts between bogs. They are not expected to be more than 2 to 3 m deep. To find a till deposit with a suitable gradation and moisture may take considerable investigation. A till pit is opened near the village of Makkovic.

The overburden in the river bed at the dam site is expected to be 1 to 2 m deep.

5.2.3 Bedrock

The bedrock geology was not examined on the ground at the dam site. Based on regional mapping reported in Phase 1, the site is underlain by rock of Precambrian age consisting of medium grained quartz granite which intrude bedded white and pink arkose, rhyolite tuff and tuffaceous sandstone. The latter appears to occur at Site MK S-2. In any case all rock types would be strong and faintly weathered

The MK-S2 site is on an anticlinal fold axis plunging nearly N-S. Faulting is not indicated.

5.2.4 Construction Materials

Figure 5-3 shows in a general way there is a reasonable chance of finding glacial till, sand and gravel for concrete or filter. Processing will be required to produce concrete aggregate or filters. Sand and gravel taken from the braided stream near round Pond is expected to be below the water table.

Rock fill is common although not indicated on Figure 5-3.

5.2.5 Design Considerations

The bedrock is considered to be of good quality and suitable for a dam or powerhouse structure. The powerhouse structure will be located near the braided stream and the assumption for the present time is bedrock is overlain by 2-3 m of sand and gravel.

At this level of information, the dams should be designed as zoned embankment structures unless Site 1 dam is suitable for a concrete option given the narrow river section.

The bedded nature of Site MK S-2 may take more grout that the granitic foundation.

5.3 Site 8

5.3.1 Setting

Site 8 is located in a narrow section on the St. Lewis River at its lower end about 8 km from Port Hope Simpson. The river is about 50 m wide at the dam site location and the slopes rise about 1V:3H on both sides.

5.3.2 Soils

Two types of soils exist at the dam site proper (Figure 5-4). One is alluvium which is restricted to the river course. The riverbed surface comprises a collection of gravel to small boulders while the substrate is expected to have a sand matrix below its surface.

The other soil type is less defined and is expected to be topsoil and till, less than 1 m thick and sitting directly on bedrock. At times, bedrock outcrops occur through the soil veneer. The overburden supports a tree cover with trees as tall as 5 to 7 m high.

5.3.3 Bedrock

Bedrock is exposed along the river's edge and rises to about 3 to 5 m above the river level in most areas (Figure 5-5 and Photo 4). Sometimes bedrock outcrops in the forested area at higher elevations.

The bedrock consists of medium grained, pink, crystalline, faintly weathered, strong, jointed granite on both sides of the river. The granite is dominated by a strong fracture zone that strikes across the river from the downstream end of the spillway to the intake structure (Photos 5 and 6). The limits of the fracture zone are not well defined at the present time. The zone may not be as wide as shown. Additional work is required to define the northern limit especially. The fracture zone, as seen on both sides of the river, is high angle, with fracture spacing 50-300 mm but generally at the lower end of the range. The fractures appear tight on the river bank and are orientated on one direction. Shearing or faulting was not observed.

5.3.4 Construction Materials

The construction materials required for the cofferdam and dam construction are impervious till, sand and gravel deposits for filters and concrete aggregate and bedrock for rock fill.

The greatest potential for till, and sand and gravel are on the south side of the river within several kilometers of the dam site. The north side is generally barren and rocky. Potential areas for till and alluvium are shown in Figure 5-4.

Wide belts of heavily forested areas exist along the south side of the river within several kilometers of the dam. The till deposits are expected to be mainly shallow with localized areas having adequate depths of till for pit operation.

Three potential areas for granular material are identified in Figure 5-4. High banks of sand were observed on the north side of the inlet. The alluvium in the river at the dam site should be available for construction either as a concrete aggregate or fill material in the cofferdams or the dam. The volumes are assumed to be moderate, < 5000 m3.

Rock fill is available in abundance beside the dam.

5.3.5 Design Considerations

The alluvium is assumed to be 1-2 m deep and will have to be removed for dam construction in the area of the core and filters.

The granite will make a strong foundation for the earth dam and concrete structures, even in the fractured rock.

A grout curtain will be required to 60% of the head. The fracture zone is expected to be more permeable member of the granite.

5.4 ALX

5.4.1 Setting

The Alexis River hydro site is located on Alexis River about 40 km west of Port Hope Simpson. The site is situated at a rocky falls that has an unusual point jutting out into the river on its south side (Photo 7). The point restricts the flow in the river. Immediately upstream of the point, and located in a cove setting, is an island with rocky edges that help to guide the river flow to the falls (Figure 5-6).

5.4.2 Soils

The dominant soil is sand and sometimes with a gravel component. The sand exists on the high terrain to the north of the site, on the south end of the point that juts into the river, and it dominates the river shoreline to the south of the dam site. The sand appears to be glacio-fluvial in origin and is expected to be deep, possibly greater than 3 m at the current position of the diversion structure. See Figure 5-6.

Forest exists over shallow bedrock in the area of the intake and along the penstock route to the powerhouse (Photo 8). The soil is not expected to be more than a meter or so deep.

A shallow body of soil appears to exist at the intake area. An extension of this material, possibly alluvium is expected to form the substrate of the river where the cofferdam is located.

5.4.3 Bedrock

Bedrock is exposed along the north edge of the Alexis River, at the falls, around the edge of the island, and around the north shoreline of the point (Photo 8 and Figure 5-6). The bedrock is Precambrian in age with mafic and granitic dyke intrusions. The gneiss is medium grained, light colored, well foliated, faintly weathered and strong. The gneiss is strongly jointed with open stressed relief joints along the north shoreline especially downstream of the falls. In areas near the water the rock is also ice-jacked.

The bedrock will make a strong foundation for concrete and earth structures. Where the rock is open, either because of stress relief jointing or ice jacking, grouting will be required. The open joint structure should not exceed 3 m depth.

5.4.4 Cofferdam Foundation

The larger cofferdam area upstream of the falls is expected to be underlain by a body of alluvium possibly 1-2 m deep. The other cofferdam will be founded directly on bedrock that has a potential of being ice jacked mostly along the foliation planes. Some of the open planes will be open and others may be filled with silt, sand and organics.

5.4.5 Construction Materials

The general soil types are defined in Figure 5-7. The dominant soil type is glacio-fluvial sand. The sand forms thick deposits on both sides of the falls including vast areas downstream. The sand appears to have a gravel component in places. These deposits are sources of filter and concrete aggregate.

Rock fill for the cofferdams is available from the north side of the canal or within 500 to 1000 m downstream of the dam on the right side.

Till, as a source of impervious fill to be placed on the upstream side of the cofferdams, is expected to occur on the steeper terrain to the south of the falls.

5.4.6 Design Considerations

The gneiss will make a suitable foundation for a dam or powerhouse foundation. Grouting at the dam will be required and the bedrock is expected to tighten up in 3 to 5 m depth.

The main cofferdam may leak through the foundation if not treated during construction. It may be easier to handle the water which may be in the order of 1 to 1.5 m^3/min.

Topographically, the point of land at its south end appears to make an excellent location for diversion works. Unfortunately, most of the bank is sand and the diversion could be located on bedrock immediately to the north. The diversion works at this location may be tight against the cofferdam, however.

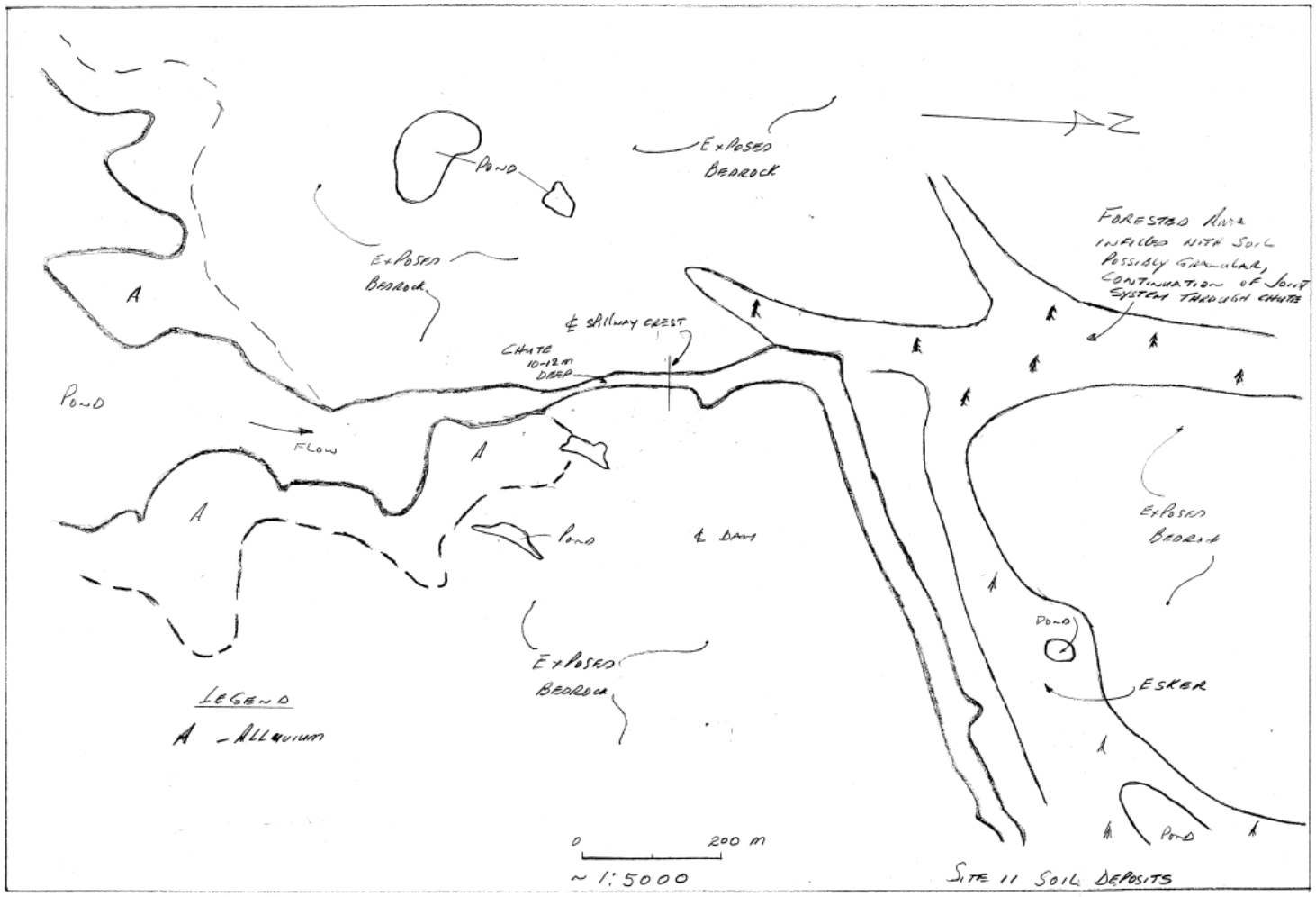


Figure 5-1: Site 11 Soil Deposits

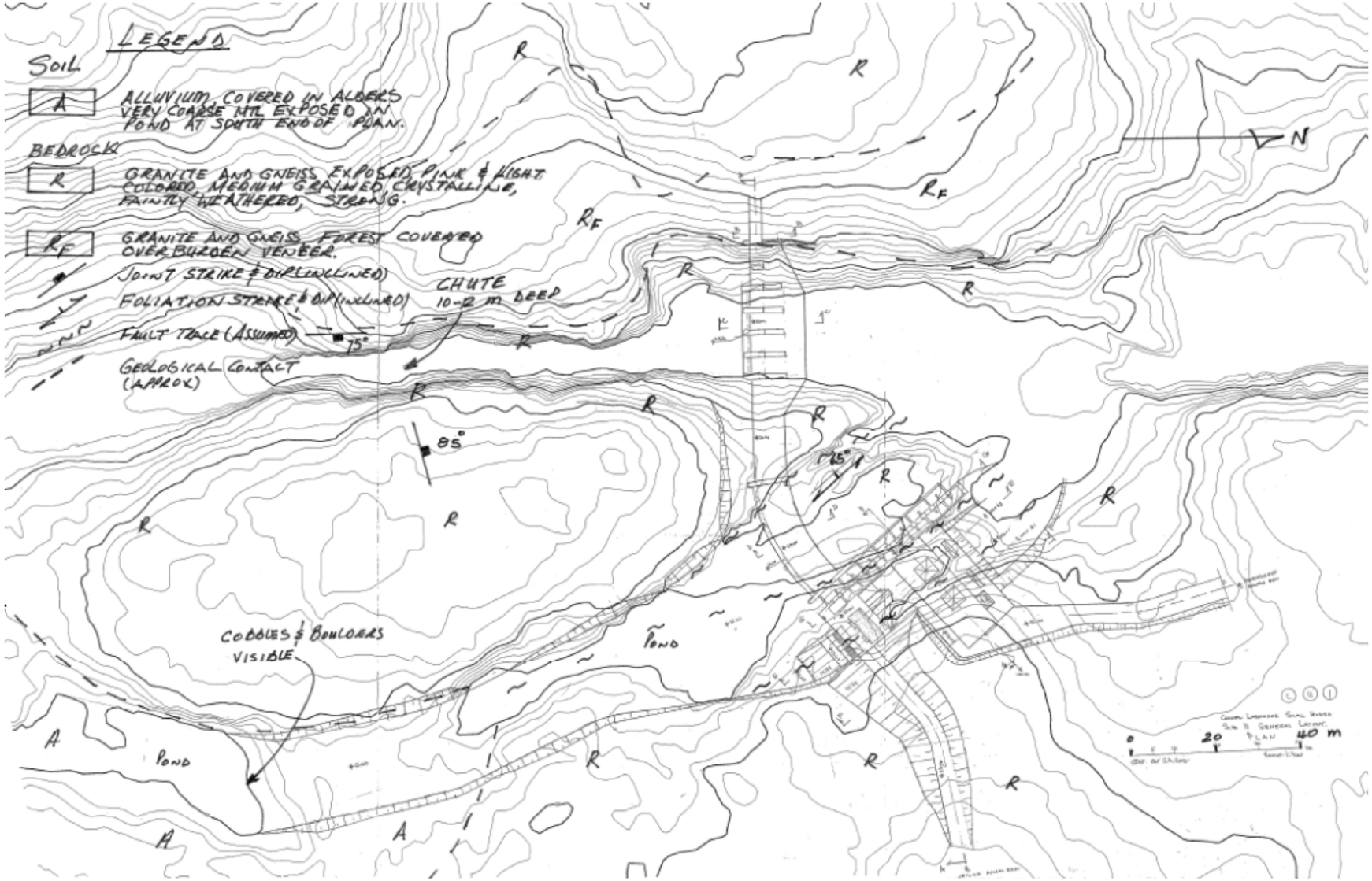
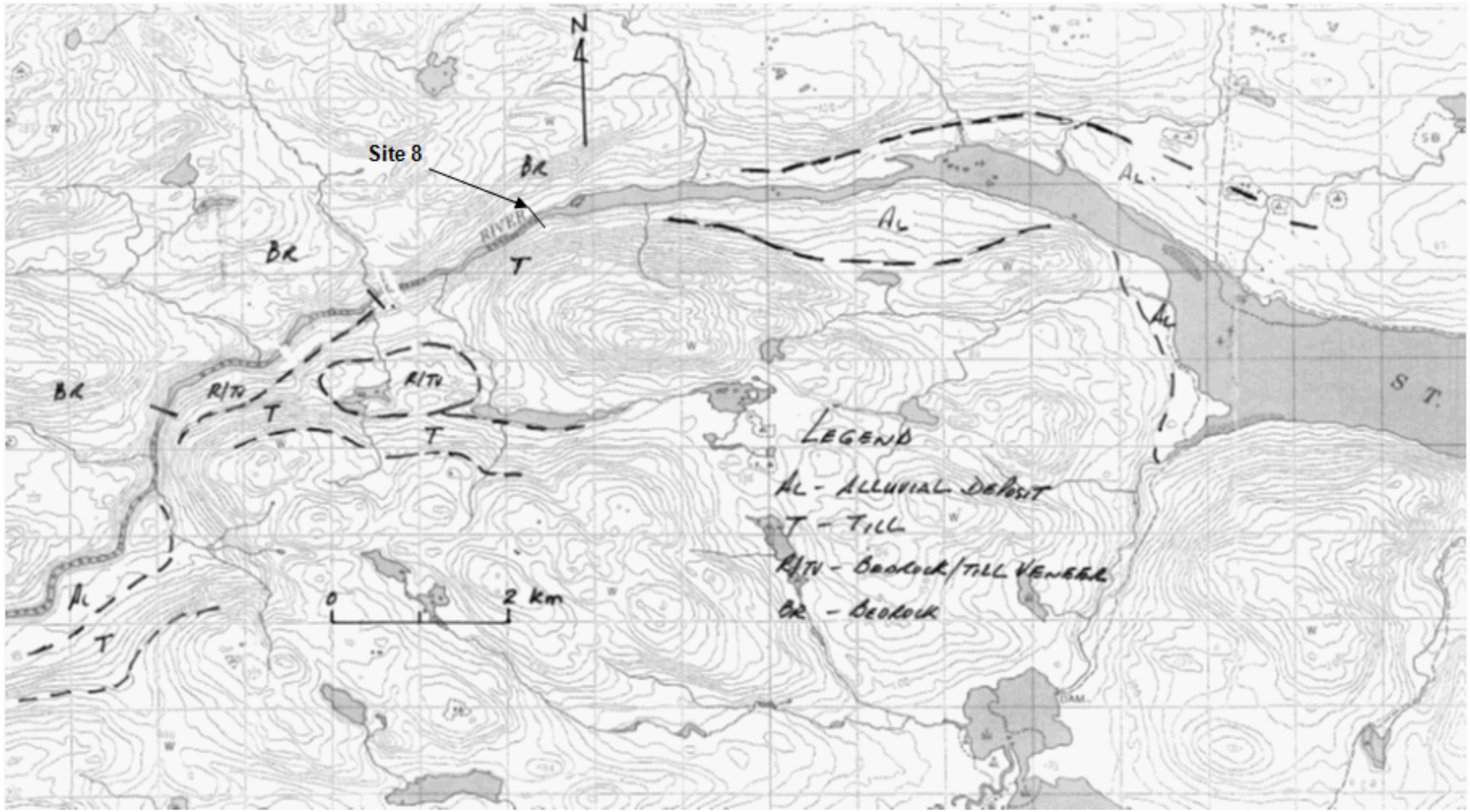


Figure 5-2: Site 11 Geology



Figure 5-3: Potential Soil Deposits in the Vicinity of MK S-2

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Site 5-4: Site 8 Potential Construction Materials

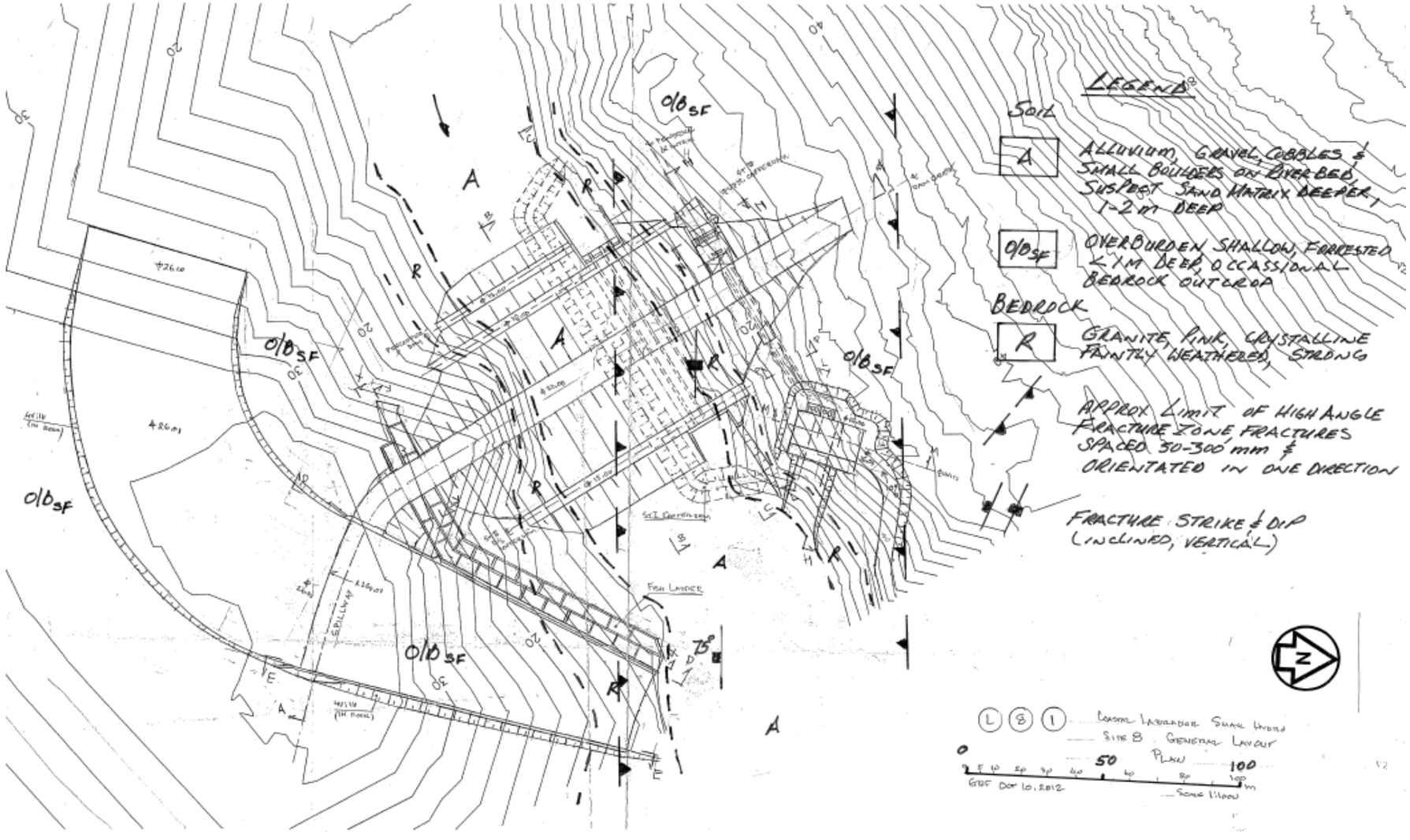


Figure 5-5: Site 8 Geology

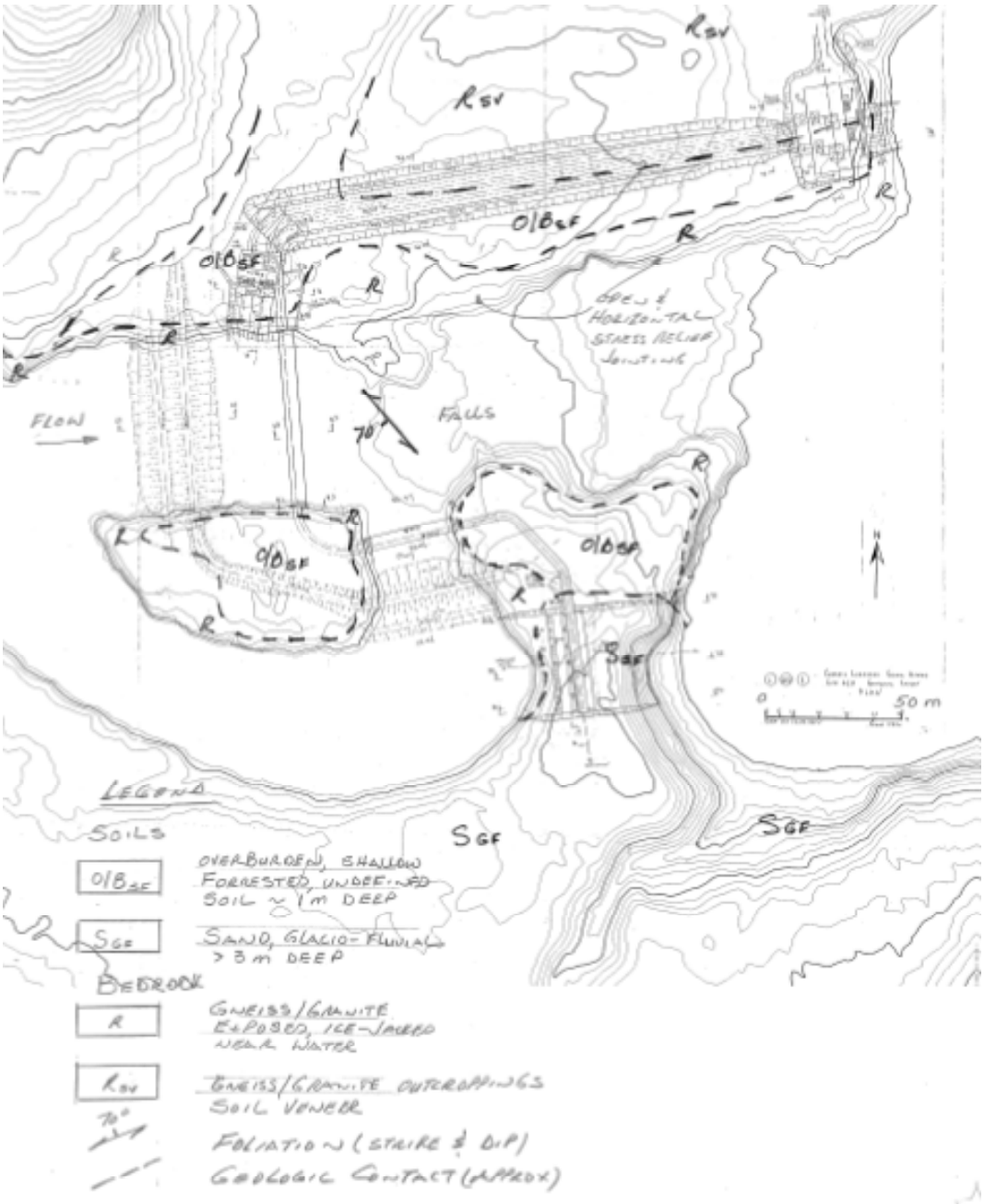


Figure 5-6: Alexis River Site Geology

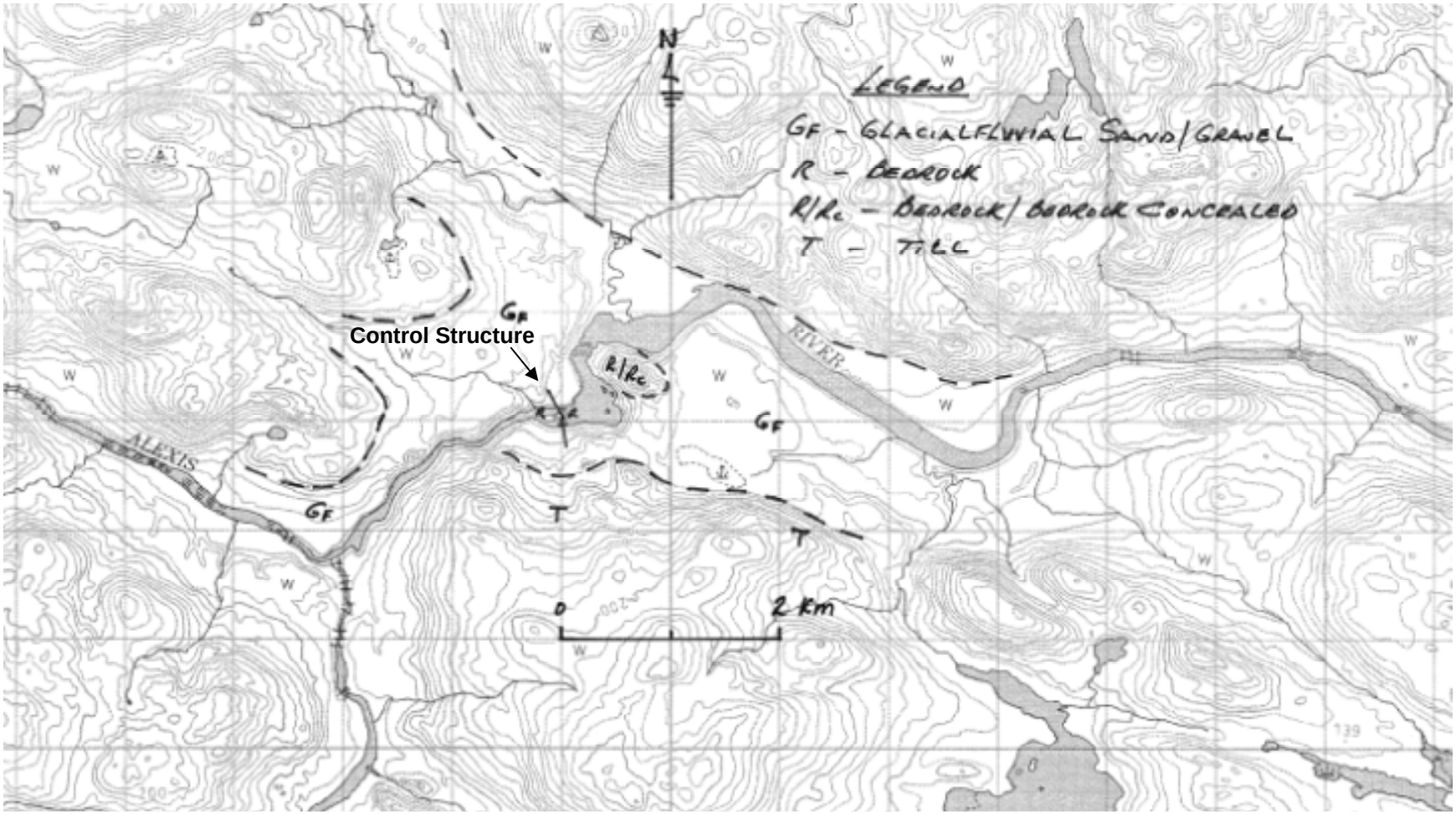


Figure 5-7: Alexis River Site, Potential Construction Materials



Photo 1: Site 11 Dam Location, Shown in Red



Photo 2: MK S-2 Proposed Dam Site, Looking Upstream, Location Shown with Red Line



Photo 3: MK S-2 Powerhouse Site



Photo 4: Site 8 Looking Downstream, Centerline of the Dam is Shown in Red



Photo 5: Site 8, Southern Limit of Fracture Zone at the Downstream End of the Spillway, Note the Parallel Fracturing



Photo 6: Site 8, Fracture Zone on North Side of the River



**Photo 7: Alexis River Dam Site, Downstream View
(One Overflow Weir Portion Shown in Red**

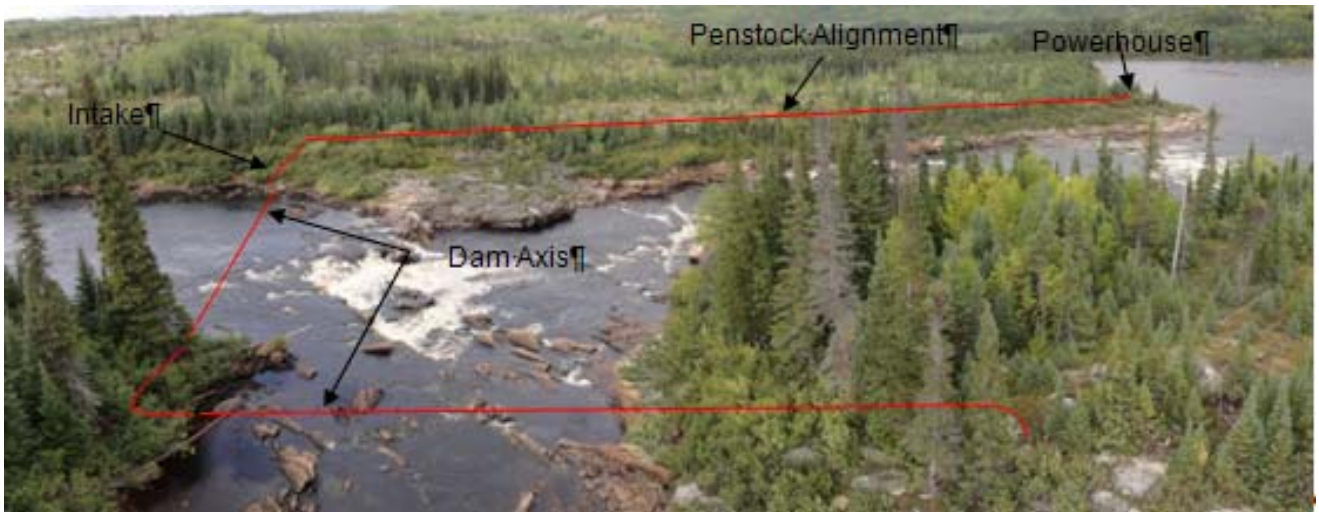


Photo 8: Terrain and Bedrock Exposure at the Alexis River Site

6. Project Descriptions

6.1 Overview

The arrangement of structures completed in Phase 1 of the project were updated based on recently acquired LiDAR survey, observations from the Phase 2 site visit and additional engineering design work. Structures were strategically arranged based on the existing geographic and topographic features of the sites.

6.2 Layout Changes

The following changes were made to the general arrangements at the various sites between the Phase 1 report and the current report.

6.2.1 Site 11

The arrangement of Site 11 was revised based on LiDAR survey of the area and the Phase 2 site visit. The new layout includes an intake structure, two penstocks, a two unit powerhouse, a fish passage, a longer overflow spillway and a small embankment wing dam.

The powerhouse has been changed from a close coupled arrangement with two 1000 kW vertical Kaplan turbines to an arrangement with two penstocks approximately 10 m in length with two 750 kW vertical Kaplan turbines (changed from 2000 kW to reflect load forecasts).

The dam arrangement was relocated slightly downstream to increase the crest length of the spillway and spill capacity and reduce the amount of excavation required. As a result of lengthening the spillway, the crest elevations of the intake structure and wing dams have been lowered.

The Adlatok River is a scheduled salmon river; hence a fish passage has been incorporated into the layout. The fish passage was not shown in the Phase 1 layout.

A 52 m long zoned embankment wing dam with a maximum height of 5 m has been added to the right side of the arrangement between the intake structure and the right river bank.

6.2.2 Site MK S-2

Recently acquired LiDAR data of Makkovik Brook provided detailed topography of the area. Aerial viewing during the Phase 2 Site Visit aided in optimizing the arrangement of structures.

The Phase 2 arrangement is similar to the Phase 1 layout and includes a concrete gravity non-overflow main dam, a concrete overflow spillway, fish passage, intake structure, penstock and powerhouse. The Phase 2 head works was moved upstream to a more favourable location.

Makkovik Brook is a scheduled salmon river; hence a small fish passage has been incorporated into the layout. The fish passage was not included in the Phase 1 layout.

The powerhouse consists of two 500 kW horizontal Francis turbine units and a 0.9 m diameter synchronous valve for surge suppression.

6.2.3 Site 8C

A tourist/ fishing lodge upstream of this site limits the elevation of the headpond. On account of the lodge, the dam location was changed to Site 8C approximately 260 m downstream of the proposed Phase 1 dam site.

A 23.5 m embankment dam with a cement/bentonite slurry core wall is proposed. The Phase 1 dam was a 34 m high zoned earthfill structure with an impermeable fill core. Similar to the previous arrangement a large chute spillway is located in an excavated channel in the right bank of the valley.

The right and left embankment wing dams proposed in Phase 1 (for the original 8A site) are not required for the Phase 2 8C layout.

As the St. Lewis River is a scheduled salmon river, a fish passage has been incorporated into the updated layout. The fish passage was not shown in the Phase 1 layout.

6.2.4 Site ALX

Based on field observations and LiDAR survey, the Phase 1 ALX site layout was modified for Phase 2. As noted during the site visit, the low, sandy terrace on the left bank of the Alexis River is a natural location for the powerhouse. The location of the powerhouse was relocated from the right river bank to the left bank to take advantage of existing geographic features, and proximity for road access and transmission.

The new arrangement consists of an intake, two penstocks, powerhouse, three concrete overflow spillways, and non-overflow concrete gravity dam sections between the spillways.

A concrete diversion structure will be constructed in a channel on the right side of the arrangement. The diversion structure will be replaced with an ogee shaped overflow supplementary spillway during the final stage of construction.

Two concrete ogee shaped main overflow spillways will be constructed on either side of the island. The overflow sections are connected with non-overflow concrete gravity dams. The previous arrangement included a single overflow spillway running perpendicular to the river alignment at the falls on the left side of the dam.

The intake of the powerhouse is located on the left side of the river immediately upstream of the dam. The intake controls flow into two 3.0m diameter 175m long penstocks which convey the power flow to two 2200 kW vertical Kaplan turbines in the powerhouse. In the previous layout, the powerhouse consisted of a close coupled arrangement with two 2500 kW horizontal Kaplan turbines.

6.3 Civil Works

6.3.1 Site 11 - Layout and Features

The Site 11 hydro scheme is located 45 km southwest of the community of Hopedale on the north branch of the Adlatok River, which flows northwards to Adlatok Bay. The proposed

Site 11 dam would divert flows from the river to a powerhouse to be constructed on the left river bank approximately 10 m immediately downstream of the dam. The dam site would be located at approximate coordinates 6,117,500 m Northing and 268,338 m Easting.

A concrete gravity dam approximately 165 m in length and with a maximum height of 5.0 m is proposed for this site. The length of the dam will be approximately 113 m and will incorporate an intake structure on the right river bank as well as a fish passage to the left of the intake. The remainder of the concrete gravity dam will consist primarily of a concrete ogee shaped overflow spillway with its crest at elevation 20.00 m and a short concrete gravity dam section with a crest elevation of 24.00 m tying into bedrock on the left river bank. An earthfill embankment wing dam approximately 52 m in length will be constructed to the right of the intake structure tying into bedrock on the right river bank. The earthfill dam will be constructed of compacted random fill with an impervious fill core and will have a crest elevation of 24.00 m.

The intake structure will have two 1.75 m wide by 2.20 m high gate openings at an invert elevation of 14.40 m. The vertical lift gates will be operated by hoists housed inside a building on the crest of the dam. The two gate openings will each transition into 2.20 m diameter steel penstocks approximately 15 m in length conveying water to the powerhouse downstream of the dam.

The fish passage will be a reinforced concrete structure with approximately 15 pools with the invert elevation of the top pool at elevation 17.50 m and the invert elevation of the bottom pool at elevation 10.00 m. A 1.1 m wide by 1.1 m high gate will be provided to control water flows into the fish passage.

The foundation of the powerhouse will be excavated in bedrock to elevation 5.80 m with the powerhouse floor elevation at 15.00 m and the normal tailwater level (TWL) at 10.00 m. Two vertical-axis Kaplan turbines are proposed for the powerhouse with a total installed capacity of 1500 kW (2 x 750 kW units). The transformer for the generating station will be located adjacent to the right side of the powerhouse for easy connection to the power transmission line.

A transmission line will be constructed from the powerhouse over land a distance of approximately 45 km to the community of Hopedale. An access road will be constructed from the powerhouse for a distance of approximately 3 km to Adlatok Bay where a dock facility will be constructed. Due to the remote location of the site, no permanent access road is planned between the powerhouse and the community of Hopedale. Figure 6-1 shows the proposed transmission line from Site 11 to Hopedale.

The system characteristics for Site 11 are summarized in Table 6-1. The project drawings (general arrangement, profiles, sections and details) are shown in Appendix D-1.

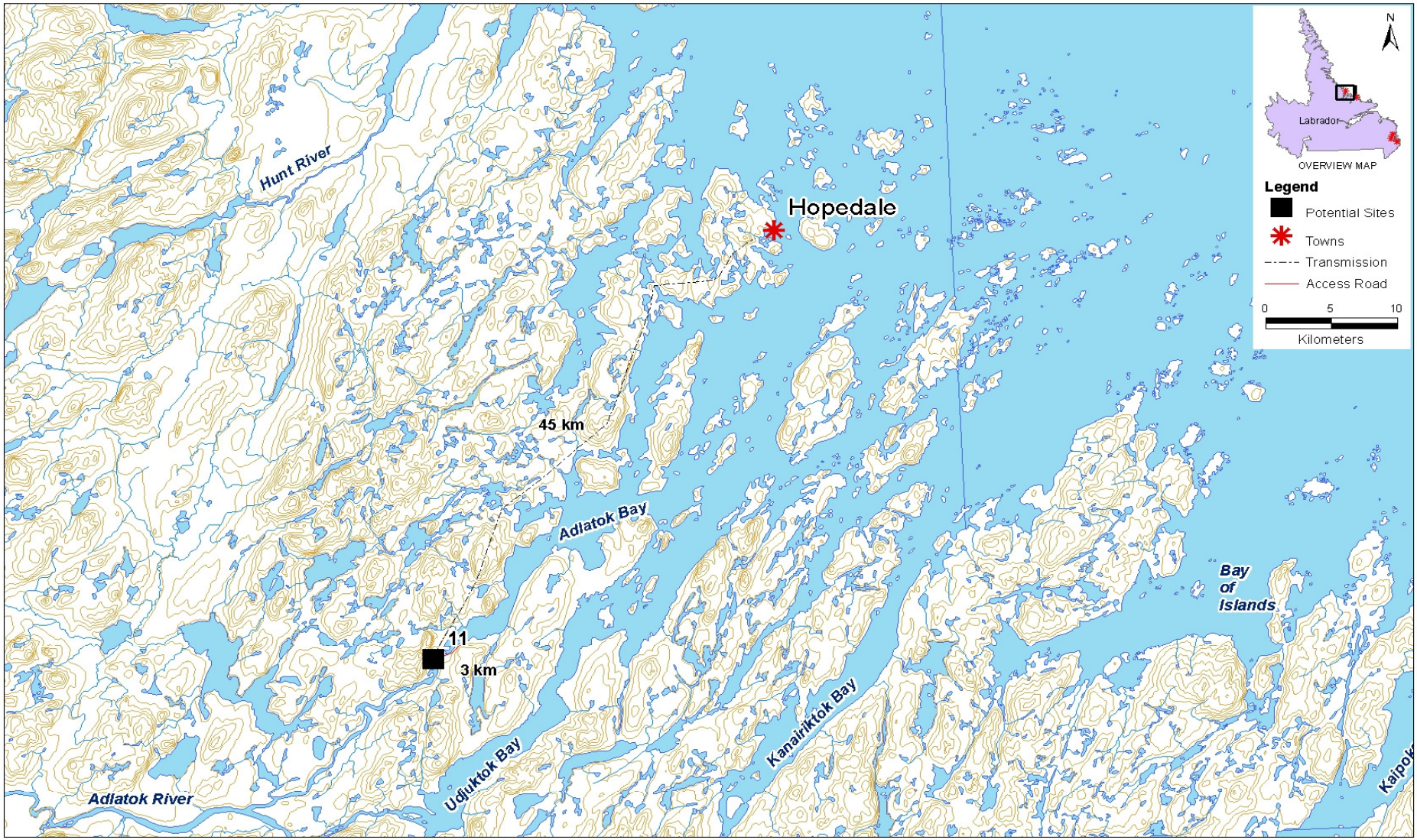


Figure 6-1
Hopedale - Transmission Lines and Access Roads
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro

Table 6-1: Site 11 System Characteristics

Description	Units	Site 11
Basin Hydrology		
River basin Ref/Name		Adlatok R.
Basin drainage area	km^2	5,623
Estimated site MAF	m^3/s	125
50% exceedance flow in sequence	m^3/s	67.6
95% exceedance flow in sequence	m^3/s	12.7
Main Dam		
Coordinates of Dam CL and River a/		
Northing	m	6,117,500
Easting	m	268,338
Type		Impervious Core Embankment Dam
Design Flood (1/100 Year AEP)	m^3/s	1150 b/
Design Flood Water Level	m	23.87
Dam crest elevation	m	24.0
Length of the dam crest	m	52.0
River Bed elevation	m	19.0
Dam Height	m	5.0
Spillway		
Type		Ogee Crested Overflow
Design Flood (1/100 Year AEP)	m^3/s	2023
Design Flood Water Level	m	23.87
No. of openings	No.	8
Total length of primary spillway	m	75.5
Crest elevation of primary spillway (FSL)	m	20.0
Intake Structure		
Intake design flow	m^3/s	18.0
Normal operating level (FSL)	m	20.0
Intake sill elevation	m	14.4
Intake deck elevation	m	24.0
Gate type		Vertical Lift
Number of gates	No.	2
Width of gate	m	1.8
Height of gate	m	2.2
Diameter of gate	m	N/A
Total free waterway width of the intake	m	11.7
Water Conveyance System - Penstock		
Type of water conductor & penstock		Twin pipes
Penstock material		Steel
Length	m	15.0
Internal diameter	m	2.2
Design Flow/pipe or penstock	m^3/s	9.0
Mean pipe velocity at design flow	m/s	2.4
Powerhouse		
Type of turbine units		Vertical Kaplan
Number of units	No.	2
Total Installed capacity	MW	1.5
Gross head	m	10.0
Net head	m	9.5
Plant Design flow	m^3/s	18.0
Turbine unit rated flow	m^3/s	9.0
Minimum flow/turbine unit	m^3/s	3.6
Surge supressor valve in PH	Yes/No	No
Tailwater level at design flow	m	10.0
Centre line of distributor elevation	m	10.8
Assumed plant efficiency c/	%	89

Notes:
a/ UTM NAD83 zone 21N used as coordinate system
b/ Flood estimates at Site 11 are calculated based on the proration of flows in a branching section of the river
c/ Plant efficiency includes - turbine efficiency (92.5%), generator efficiency (97%), Transformer efficiency (98.5 % to 99%)

6.3.2 Site MK S-2 – Layout and Features

The Site MK S-2 hydro scheme is located 7 kilometers southwest of the community of Makkovik on Makkovik Brook, which flows northwards to Makkovik Bay. The proposed Site MK S-2 dam would divert flows from the brook to a powerhouse to be constructed on the right river bank approximately 1650 m downstream of the dam. The dam site would be located at approximately coordinates 6,098,166 m Northing and 361,916 m Easting.

A concrete gravity dam approximately 80 m in length with a maximum height of 8.5 m is proposed. Its crest elevation is 131.50 m and will incorporate an intake structure on the right river bank, a short fish passage, a 15 m long concrete ogee shaped overflow spillway with its crest at elevation 130.00 m, and a 50 m long concrete gravity dam section with a crest elevation of 131.50 m tying into bedrock on the left river bank. The fish passage will be a reinforced concrete structure with its top pool invert elevation at 127.50 m and the bottom pool invert at elevation 124.00 m.

A 2 m wide intake structure with transition to a single 0.90 m diameter penstock with its invert at 127.50 m will be located at the head works. The penstock inlet will have service and maintenance butterfly valves housed inside a building on the crest of the dam. The penstock will traverse the right river bank from the intake structure for a length of 1638 m to the powerhouse. A high density polyethylene (HDPE) pipe or glass reinforced (GRP) penstock is proposed for this site due to its long length. Most of the penstock will be buried in a trench excavated in bedrock although some sections will require burial in embankment sections constructed above original ground. Approximately 10 concrete anchor and thrust blocks will be required along the route. The high pressure section of the penstock will start approximately 340 m upstream of the powerhouse. A bifurcation located approximately 10 m upstream of the powerhouse will provide two branches including a 0.90 m diameter penstock to the turbine units and a second 0.90 m diameter branch section leading to a synchronous valve that will perform as a surge suppressor (in lieu of a surge tank). A second bifurcation of the 0.90 m diameter penstock branch located approximately 5 m upstream of the powerhouse will split into two 0.50 m diameter penstock sections leading to the two horizontal Francis turbine units.

The foundation of the powerhouse will be excavated in bedrock to elevation 48.00 m with the powerhouse floor elevation at 53.00 m and the normal tailwater level (TWL) at 49.37 m. The gross head on the Site MK S-2 hydroelectric scheme will be 80.6 m.

A transmission line will be constructed from the powerhouse over land a distance of approximately 6.5 km to the community of Makkovik. An access road will be constructed adjacent to the transmission line from Makkovik to Makkovik Brook and then cross a bridge to the powerhouse. The proposed access road and transmission line are indicated in Figure 6-2.

The system characteristics for Site MK S-2 are summarized in Table 6-2. The MK S-2 drawings are provided in Appendix D-2.



Figure 6-2
Makkovik - Transmission Lines and Access Roads
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro

Table 6-2: Site MK S-2 System Characteristics

Description	Units	Site MK S-2
Basin Hydrology		
River basin Ref/Name		Makkovik Brook
Basin drainage area	km^2	74
Estimated site MAF	m^3/s	1.6
50% exceedance flow in sequence	m^3/s	0.47
95% exceedance flow in sequence	m^3/s	0.06
Main Dam		
Coordinates of Dam CL and River a/		
Northing	m	6,098,166
Easting	m	361,916
Type		Concrete Gravity Dam
Design Flood (1/100 Year AEP)	m^3/s	45.5
Design Flood Water Level	m	131.36
Dam crest elevation	m	131.5
Length of the dam crest	m	47.3
River Bed elevation	m	123
Dam Height	m	8.5
Spillway		
Type		Ogee Crested Overflow
Design Flood (1/100 Year AEP)	m^3/s	45.5
Design Flood Water Level	m	131.36
No. of openings	No.	2
Total length of primary spillway	m	15.0
Crest elevation of primary spillway (FSL)	m	130.0
Intake Structure		
Intake design flow	m^3/s	1.5
Normal operating level (FSL)	m	130.0
Intake sill elevation	m	127.5
Intake deck elevation	m	131.5
Gate type		Butterfly Valve
Number of gates	No.	1
Diameter of gate	m	0.9
Total free waterway width of the intake	m	4.0
Water Conveyance System - Penstock		
Type of water conductor & penstock		single pipe
Penstock material		Fibreglass
Length	m	1638.0
Internal diameter	m	0.9
Design Flow/pipe or penstock	m^3/s	1.5
Mean pipe velocity at design flow	m/s	2.4
Diameter of bifurcation	m	0.5
Length of bifurcation	m	6
Powerhouse		
Type of turbine units		Horiz. Francis
Number of units	No.	2
Total Installed capacity	MW	1.0
Gross head	m	80.6
Net head	m	74.4
Plant Design flow	m^3/s	1.5
Turbine unit rated flow	m^3/s	0.8
Minimum flow/turbine unit	m^3/s	0.3
Surge supressor valve in PH	Yes/No	Yes
Tailwater level at design flow	m	49.0
Centre line of distributor elevation	m	51.7
Assumed plant efficiency c/	%	89

Notes:
a/ UTM NAD83 zone 21N used as coordinate system
b/ Flood estimates at Site 11 are calculated based on the proration of flows in a branching section of the river
c/ Plant efficiency includes - turbine efficiency (92.5%), generator efficiency (97%), Transformer efficiency (98.5 % to 99%)

6.3.3 *Site 8C – Layout and Features*

The Site 8C hydro scheme is located approximately 8 km south of the community of Port Hope Simpson on the St. Lewis River, which flows eastwards to St. Lewis Inlet. Site 8C is the revised location of Site 8 from the Phase 1 report and is 265 m downstream of the original Site 8. The proposed Site 8C dam would divert flows from the river to a powerhouse to be constructed on the left river bank immediately downstream of the dam. The dam site would be located at approximately coordinates 5,810,046 m Northing and 545,751 m Easting.

The dam proposed for this site will be approximately 210 m in length. The main dam section will be 104 m in length with a maximum height of 23.5 m consisting of an embankment structure with a cement/bentonite slurry core wall. The intake structure will be excavated in bedrock at the left river bank immediately to the left of and incorporated into the main embankment dam. A fish passage will be constructed immediately to the right of the main embankment dam. The fish passage will be a reinforced concrete structure with approximately 24 pools with its top pool invert at elevation 30.80 m and the bottom pool invert at elevation 16.70 m. A concrete ogee shaped gravity overflow spillway 60 m in length with an upstream approach channel and downstream chute will be excavated in bedrock along the right river bank. A concrete gravity wing dam approximately 20 m in length will be constructed to the right of the spillway to tie into bedrock at the right river bank. The embankment dam, intake structure crest, fish passage crest and concrete wing dam will have a crest elevation of 38.50 m while the concrete overflow spillway crest will be at elevation 33.50 m.

The intake structure will comprise two 1.60 m wide by 2.00 m high gate openings at an invert of 26.50 m. The vertical lift gates will be operated by hoists housed inside a building on the crest of the intake structure. The two gate openings will each transition into 2.00 m diameter steel penstocks approximately 60 m in length conveying water to the powerhouse located on the left river bank immediately downstream of the dam. The penstocks will be buried in a trench excavated in bedrock. The sections of penstock beneath the embankment dam will be encased in concrete.

The foundation of the powerhouse will be excavated in bedrock to elevation 9.0 m with the powerhouse floor elevation at 20.50 m and the normal tailwater level (TWL) at 15.50 m. The gross head at Site 8C will be 18.0 m and the net head is estimated to be 17.0 m. Two vertical-axis Kaplan turbines are proposed for the powerhouse with a total installed capacity of 4400 kW (2 x 2200 kW units).

An access road will be constructed from the Trans-Labrador Highway to the powerhouse for a distance of approximately 10 km. The transmission line will follow the access road route to the Trans-Labrador Highway then continue north alongside the highway to Port Hope Simpson for a total distance of 24 km. Figure 6-3 shows the proposed access roads and transmission line from Site 8C to Port Hope Simpson, and, shows the interconnection lines to Charlottetown and Mary's Harbour.



Figure 6-3
Charlottetown, Port Hope Simpson, & Mary's Harbour - Transmission Lines and Access Roads
Feasibility Study of Hydraulic Potential of Coastal Labrador
Newfoundland Labrador Hydro

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The system characteristics of Site 8C are summarized in Table 6-3. The general arrangement, profiles, sections and detailed drawings for Site 8C are shown in Appendix D-3.

Table 6-3: Site 8C Layout Characteristics

Description	Units	Site 8C
Basin Hydrology		
River basin Ref/Name		Lewis R.
Basin drainage area	km^2	2,403
Estimated site MAF	m^3/s	61
50% exceedance flow in sequence	m^3/s	32.6
95% exceedance flow in sequence	m^3/s	6.6
Main Dam		
Coordinates of Dam CL and River a/		
Northing	m	5,810,046
Easting	m	545,751
Type		Slurry Wall Embankment Dam
Design Flood (1/100 Year AEP)	m^3/s	932
Design Flood Water Level	m	37.56
Dam crest elevation	m	38.50
Length of the dam crest	m	104
River Bed elevation	m	15.00
Dam Height	m	23.5
Spillway		
Type		Ogee Crested Overflow
Design Flood (1/100 Year AEP)	m^3/s	932
Design Flood Water Level	m	37.56
No. of openings	No.	1
Total length of primary spillway	m	60.0
Crest elevation of primary spillway (FSL)	m	33.50
Intake Structure		
Intake design flow	m^3/s	29.7
Normal operating level (FSL)	m	33.50
Intake sill elevation	m	26.50
Intake deck elevation	m	38.50
Gate type		Vertical Lift
Number of gates	No.	2
Width of gate	m	1.6
Height of gate	m	2.0
Total free waterway width of the intake	m	10.8
Water Conveyance System - Penstock		
Type of water conductor & penstock		Twin pipes
Penstock material		Steel
Length	m	60.0
Internal diameter	m	2.0
Design Flow/pipe or penstock	m^3/s	14.9
Mean pipe velocity at design flow	m/s	4.7
Powerhouse		
Type of turbine units		Vertical Kaplan
Number of units	No.	2
Total Installed capacity	MW	4.4
Gross head	m	18.0
Net head	m	17.0
Plant Design flow	m^3/s	29.7
Turbine unit rated flow	m^3/s	14.9
Minimum flow/turbine unit	m^3/s	5.9
Surge supressor valve in PH	Yes/No	No
Tailwater level at design flow	m	15.50
Centre line of distributor elevation	m	15.80
Assumed plant efficiency c/	%	89

Notes:
a/ UTM NAD83 zone 21N used as coordinate system
b/ Flood estimates at Site 11 are calculated based on the proration of flows in a branching section of the river
c/ Plant efficiency includes - turbine efficiency (92.5%), generator efficiency (97%), Transformer efficiency (98.5 % to 99%)

6.3.4 *Site ALX – Layout and Features*

The Site ALX hydro scheme is located approximately 40 km northwest of the community of Port Hope Simpson on the Alexis River, which flows eastwards to Alexis Bay. The proposed Site ALX dam would divert flows from the river to a powerhouse to be constructed on the left river bank approximately 200 m downstream of the dam. The dam site would be located at approximately coordinates 5,833,303 m Northing and 508,918 m Easting.

A concrete gravity dam/overflow spillway structure is proposed for this site that will be approximately 260 m in total length and will incorporate three concrete ogee shaped overflow spillways with lengths of 38 m, 41 m and 55 m separated by non-overflow gravity dam sections. The concrete dam will tie into bedrock on both the left and right banks. An intake structure will be excavated in bedrock on the left river bank immediately upstream of the concrete dam. The non-overflow sections of the dam and the intake structure will have a crest elevation of 48.50 m. The right and center main overflow spillway sections will have a crest elevation 45.00 m while the left secondary spillway section will have a crest elevation of 46.50 m.

The intake structure will have trashracks with two 2.40 m wide by 3.00 m high gate openings at an invert of 37.50 m. The vertical lift gates will be operated by two hoists housed inside a building on the crest of the intake structure. The two gate openings will each transition into 3.00 m diameter steel penstocks approximately 224 m in length conveying water to the powerhouse located on the left river bank downstream of the dam. Normal Full Supply Level (FSL) in the headpond will be at elevation 45.00 m with a maximum high water level during the 1:100 year flood at elevation 48.04 m.

The foundation of the powerhouse will be excavated in bedrock to elevation 30.00 m with the powerhouse floor elevation at 40.00 m and the normal tailwater level (TWL) at 35.00 m. The gross head at Site ALX is 10.00 m and the net head is estimated to be 8.8 m. Two vertical-axis Kaplan turbines are proposed for the powerhouse with a total installed capacity of 4400 kW (2 x 2200 kW units).

A new access road will be constructed from the Trans-Labrador Highway for a distance of approximately 18 km to the powerhouse. The transmission line will follow the access road route to the Trans-Labrador Highway then continue southeast alongside the highway to Port Hope Simpson, for a total distance of 56 km, and north to Charlottetown, and south to Mary's Harbour. The access roads and transmission lines are shown on Figure 6-3.

The system characteristics for Site ALX are summarized in Table 6-4. The ALX drawings are provided in Appendix D-4.

Table 6-4: Site ALX System Characteristics

Description	Units	Site ALX
Basin Hydrology		
River basin Ref/Name		Alexis R.
Basin drainage area	km^2	2,312
Estimated site MAF	m^3/s	52
50% exceedance flow in sequence	m^3/s	22.6
95% exceedance flow in sequence	m^3/s	5.1
Main Dam		
Coordinates of Dam CL and River a/		
Northing	m	5,833,303
Easting	m	508,918
Type		Concrete Gravity Dam
Design Flood (1/100 Year AEP)	m^3/s	1198
Design Flood Water Level	m	48.04
Dam crest elevation	m	48.5
Length of the dam crest	m	113
River Bed elevation	m	44.5
Dam Height	m	4.0
Spillway		
Type		Ogee Crested Overflow
Design Flood (1/100 Year AEP)	m^3/s	1198
Design Flood Water Level	m	48.04
No. of openings	No.	2
Total length of primary spillway	m	104.8
Crest elevation of primary spillway (FSL)	m	45.0
Total length of secondary spillway	m	38.0
Crest elevation of secondary spillway	m	46.5
Intake Structure		
Intake design flow	m^3/s	57.6
Normal operating level (FSL)	m	45.0
Intake sill elevation	m	37.5
Intake deck elevation	m	48.5
Gate type		Vertical Lift
Number of gates	No.	2
Width of gate	m	2.4
Height of gate	m	3.0
Total free waterway width of the intake	m	12.8
Water Conveyance System - Penstock		
Type of water conductor & penstock		Twin pipes
Penstock material		Fibreglass
Length	m	224.0
Internal diameter	m	3.0
Design Flow/pipe or penstock	m^3/s	28.8
Mean pipe velocity at design flow	m/s	4.1
Powerhouse		
Type of turbine units		Vertical Kaplan
Number of units	No.	2
Total Installed capacity	MW	4.4
Gross head	m	10.0
Net head	m	8.8
Plant Design flow	m^3/s	57.6
Turbine unit rated flow	m^3/s	28.8
Minimum flow/turbine unit	m^3/s	11.5
Surge supressor valve in PH	Yes/No	No
Tailwater level at design flow	m	35.0
Centre line of distributor elevation	m	36.4
Assumed plant efficiency c/	%	89

Notes:
a/ UTM NAD83 zone 21N used as coordinate system
b/ Flood estimates at Site 11 are calculated based on the proration of flows in a branching section of the river
c/ Plant efficiency includes - turbine efficiency (92.5%), generator efficiency (97%), Transformer efficiency (98.5 % to 99%)

6.4 Mechanical/Electrical Equipment

6.4.1 Turbines

Vertical Kaplan turbines with direct driven synchronous generators are proposed for the development of the low head sites, Site 11, Site 8C and Site ALX. Water will be conveyed through short parallel penstocks for the turbines at these three sites.

Each of the units with penstocks will have turbine inlet butterfly valves located inside the powerhouse between the downstream end of the unit penstock and the spiral inlet. A transition formed in concrete or steel formwork embedded in concrete will connect the downstream end of the dismantling joint on turbine inlet valve and the rectangular inlet of the spiral casing formed in concrete.

The runner blades will be of modern design, cast or fabricated in stainless steel for cavitation resistance. The draft tube for a vertical turbine comprises of the cone extending from the bottom of the discharge/throat ring, 90 degree elbow and extension. The draft tube can have a steel liner embedded in concrete for velocities in excess of 6 m/s and the remaining part formed in concrete. Alternatively the draft tube can be completely in steel, wherein the liner readily provides the form work for embedment in concrete.

In order to minimize the loss of lubricants to the environment, moving parts such as the wicket gates will operate with self lubricated bearings. The design of turbine guide bearing for a small vertical turbine can be a water lubricated bearing or grease lubricated anti-friction bearing. The oil sump tanks of hydraulic pressure units may be provided with secondary oil containment to safeguard against leakage or spill.

Horizontal Francis turbines with direct driven synchronous generators are proposed for the development of Makkovik Site MK S-2. The units will be fed by a common penstock which bifurcates at the powerhouse with the two unit penstocks terminating at the turbine inlet valves.

Each of the units will have turbine inlet butterfly valves located inside the powerhouse between the downstream end of the unit penstock and the spiral inlet.

The turbine runner will be mounted on the generator shaft extension. The runner will be of modern design, cast or fabricated in stainless steel for cavitation resistance. With the units set well above the tail water level, the draft tube elbow with its conical extension may be inclined to reduce the tail race excavation while ensuring adequate submergence of top of draft tube at minimum tail water level.

In order to minimize the loss of lubricants to the environment, moving parts such as the wicket gates will operate with self lubricated bearings. The runner is expected to be mounted on generator shaft extension.

6.4.2 Generators

The rating, principal characteristics and features of the synchronous generator will be governed by the turbine capacity and speed. The vertical generators will be directly connected to the turbines. The generators will be complete with associated brushless/static excitation system and voltage regulator system. For the proposed ratings, the generators are expected to be open air cooled.

The thrust load due to turbine will be taken by generator bearings. The generator bearings can be of antifriction type or pad type with self contained oil lubrication system. The potential loss of oil from bearings and hydraulic systems in the powerhouse will be contained with a powerhouse sump system to collect any leakage oils and other hazardous materials in conjunction with a sump and oil detector or alternatively with an oil-water separator to prevent these hazardous materials being discharged into the outside environment.

6.4.3 Turbine Controls

The generating units are required to operate in island mode, operate in parallel with existing diesel units and be capable for remote operation. A full featured digital governor is required to provide frequency control with power feed-back control and regulate the wicket gates and runner blades.

The turbine governing systems with associated hydraulic power unit are expected to be modern, high-pressure systems with nitrogen pre-charged hydraulic accumulators requiring a smaller footprint as compared to conventional air-oil pressure vessel systems and can be located on the turbine floor.

For island mode operation, the powerhouse will require black start capability to open the turbine inlet valves and crack open the wicket gates in order to start the turbines and synchronize the units. The black start capability may include DC motors with battery power or separate emergency diesel generator set or emergency supply from the existing diesel generators to be decided based on Owner's requirements.

6.4.4 Powerhouse Electrical and Mechanical Auxiliaries

6.4.4.1 Mechanical

The powerhouse mechanical auxiliaries will include hydraulic power units for the turbine and inlet valve, cooling water supply system for shaft seal and if required for bearing cooling, compressed air system for generator brake and service air, head cover drainage pumps, drainage system with oil water separator, dewatering system, heating and ventilation system, fire protection system, piping systems for oil, water and air including piezometer piping.

6.4.4.2 Electrical

The powerhouse electrical systems will include PLC based turbine controls and monitoring equipment, generator condition monitoring equipment, MV switchgear, unit and plant control, protection, metering and SCADA systems, station service transformers, LV power, control, protection, DC supply system with batteries and charger, switchyard equipment.

6.4.5 *Powerhouse Hydromechanical Equipment*

The inclined trash racks located at entrance to the intake will prevent any floating debris and ice from entering the conveyance channel and ultimately into the turbine. The trashrack is arranged in two sections with a central concrete pier. The minimum trashrack bar spacing will be governed by the turbine supplier.

The upstream service gate can be a set of stop logs or a sectional/single leaf bulkhead. With the turbine inlet valves providing the emergency closure function, the intake to penstocks at Site 11, Site 8C and Site ALX will require only stoplogs/bulkhead.

A sectional/single leaf bulkhead gate is proposed on the draft tube for dewatering the turbine and to provide access to the turbine runner for inspection and maintenance.

Considering the remote location of the sites, use of a monorail hoist for the installation and operation the intake service gates and draft tube gates may be considered.

6.4.6 *Electrical Design Considerations*

6.4.6.1 *Site 11*

The hydro power plant at Site 11 will include two 750kW hydro generators each with high resistance neutral grounding to protect the generator stator winding. The design anticipates synchronous type generators and brushless excitation systems to supply the reactive power component. This system will also operate as an islanded system requiring the responsive AVR and excitation system that can minimize voltage droop during sudden loading events. The same considerations will be true as at the previous site for the selection of the generator, turbine and governor systems to minimize frequency excursions caused by large sudden load steps or load rejections.

This design anticipates that the nominal operating voltage of the generators will be 4.16 kV. This was selected on the basis of commonality with other installed system voltages. The 45 km long distribution line from the Site 11 hydro power plant to Hopedale will require transformation both for ground isolation purposes and to minimize the line losses in this length of line. It has been assumed the distribution voltage to be 34.5kV and will require a suitable step-up transformer at the hydro power plant and a step-down transformer at the interconnecting facility to the existing Hopedale distribution system.

The line is assumed to be an overhead line with 266 KCMIL conductors to minimize losses. The complete installation will include switchgear of the appropriate voltage class with necessary instrument transformers for metering and protecting the generators, the transformers and new overhead distribution circuit to the town-site.

A line circuit breaker is included at the town site end to handle the charging of the 45 km of dead line to the generation site, energization of the remote hydro power plant transformers. A motorized line disconnect switch suitable for line protection/guarantee purposes is also provided. Paralleling and synchronizing of the hydro generators to the back-fed power from

the diesel plant will be as described above with all the necessary relaying will be provided where essential to promote a safe and reliable system design.

The hydro power plant station services when the plant is not running will normally be back-fed from the Hopedale diesel generation plant. The power distribution infrastructure of the hydro plant, including a small local emergency generator to safeguard the plant auxiliary systems in the event of a protracted line outage, will be identical to that described above. Sizing of this emergency generator to provide black start capability for the hydro power plant will be a consideration for future design phases of this project as will evaluating the various operating and maintenance scenarios where synchronizing the hydro and diesel plants may be desirable.

A single circuit overhead distribution line is anticipated sharing the poles with a fiber optic cable communications link to interconnect the hydro power plant and the diesel generator plant for the purposes of SCADA and any teleprotection requirements. It is anticipated that the hydro power plant will be operated remotely and the SCADA system will be monitored both at the existing diesel plant (or elsewhere in the community) and remotely at a Newfoundland Labrador Hydro control facility.

6.4.6.2 Site MK S-2

This design anticipates that the nominal operating voltage of the generators will be 4.16 kV; however, this can be tailored to a lower voltage during the detailed project design phase, based on equipment availability and economics. This voltage was selected to match the present Makkovik community diesel generation system; however, since there is a high probability that the existing community distribution is dependent on single phase-to-neutral loads there will be a requirement that the new hydro source establish a ground point near the exiting town site. This will require a grounded wye, isolating transformer at the town-site or a step-up transformer at the Hydro plant and a step-down transformer at the town-site. The latter has been illustrated on the single line diagram in Appendix D-5 showing a 34.5 kV distribution voltage to take advantage of the lower losses in the new line and to be consistent with the other systems under consideration. 34.5 kV is not a standard sub-transmission voltage in the province of Newfoundland and Labrador. In this particular installation for MK S-2 there is minimal load and a standard distribution line voltage of 25 kV may be suitable; however, the 25 kV voltage is likely not sufficient for the 100+ km distribution feeder for CHT/PHS/MSH. In an attempt to keep common equipment and common design elements we have provisionally selected 34.5 kV for all installations. The final selection of voltage can be evaluated technically and commercially during subsequent phases of this project.

6.4.6.3 Site 8C or Site ALX

The potential development sites designated as Site 8C and Site ALX are shown on the single line diagram in Appendix D-5 to illustrate the different feed points for the proposed network; however, only one of these will eventually be selected and developed to include two 2.2 MW hydro generators with high resistance neutral grounding systems to protect the generator

stators. The design again anticipates synchronous type generators and brushless excitation systems to supply the majority of the reactive power requirements of the communities. It should be noted that with the length of lines and distributed loads as shown on the drawings there may be a requirement for additional voltage support at the various communities in the form of capacitor banks. System modeling in the next phase of engineering will confirm this requirement. As in the previous cases this system will operate as an islanded system requiring a responsive AVR and excitation system that can minimize voltage droop during sudden loading events. Similar mechanical considerations will be required for the selection of the generator, turbine and governor systems in order to minimize frequency excursions caused by large sudden load steps or load rejections.

The nominal operating voltage of the generators at this plant will also be 4.16 kV with a step-up to 34.5 kV for the approximate 100 km distribution circuit with a step-down transformer utilized at each of the interconnecting facilities to the existing community distribution systems. This scheme provides for the ground isolation between stations that is required. The distribution line has been assumed as an overhead line with 477 KCMIL conductors. The complete installation will include switchgear of the appropriate voltage class with necessary instrument transformers for metering and protecting the generators, the transformers and new overhead distribution circuit to the town-site. Unlike the other designs this distribution system feeds multiple customers and requires some configurability for minimizing the impacts of maintenance and restoration in emergency situations. A series of sectionalizing switches have been located along the highway corridor to allow segments of the lines to be isolated and hydro power to be restored (or maintained) to the remaining communities. The number and positioning of these switches as shown is diagrammatic and will need to be confirmed upon final site selection.

Line circuit breakers are included at the town sites to handle the charging current required for the approximate 100 km of distribution line that under normal conditions would be energized from one of the town's diesel plants. This dead-bus closing of one of these breakers would also simultaneously energize the hydro power plant step-up and station services transformers. A motorized line disconnect switch suitable for line protection/guarantee purposes is also provided at each facility. Paralleling and synchronizing of the hydro generators to the back-fed power from the diesel plant will be as described above with all the necessary relaying will be provided where essential to promote a safe and reliable system design. In addition, since only one diesel plant will energize the distribution line it will be necessary that the synchronizing circuits of each village's diesel plant be capable of synchronizing to the live utility line. This provision was an option with the other villages but not in this case.

The hydro power plant station services when the plant is not running will normally be back-fed from one of the diesel generation plants. This distribution system with the synchronizing systems indicated above will have the possibility of being operated with the three towns' diesel generating plants in parallel. The inherent benefits of this configuration would be to

minimize high voltage switching operations but the details will need to be reviewed during power system studies later in the project.

The power distribution infrastructure of the hydro plant, including a small local emergency generator to safeguard the plant auxiliary systems in the event of a protracted line outage, will be identical to that described above. Sizing of this emergency generator to provide black start capability for the hydro power plant will be a consideration for future design phases of this project as will evaluating the various operating and maintenance scenarios where synchronizing the hydro and diesel plants may be desirable.

A single circuit overhead distribution line is anticipated again sharing the poles with a fibre optic cable communications link to interconnect the hydro power plant and the diesel generator plants for the purposes of SCADA and any teleprotection requirements. Due to the distributed communities, it is envisioned that there will be a sophisticated teleprotection system required between all the communities and the hydro power plant to ensure interlocking of numerous remote breakers during synchronizing activities, dead-bus line charging, and parallel generator operations. The details will be explored during subsequent project engineering. It is anticipated that the hydro power plant will be operated remotely and the SCADA system will be monitored both at the existing diesel plants (and elsewhere in the respective communities) and remotely at a NL Hydro control facility.

7. Power and Energy Studies

7.1 Methodology

Average annual energy of the potential hydro sites in Phase 1 were estimated from flow duration curves (FDC) simulated for all 11 sites. In addition to the FDCs the other main parameters used to estimate the energy were – an estimate of net head at each site; a site head loss factor for greater or less than design flows and a plant efficiency. The energy estimates determined by this method are reliable but do not indicate the inter-year and intra-year variations in generated energy. In the Phase 2 definition study a better understanding of the variation of energy generation over time is required particularly to demonstrate the months where energy generated would not meet projected demand. A different approach was therefore adopted to provide these additional parameters.

The energy generation for the four hydro schemes studied under Phase 2 was estimated using Hatch's proprietary hydropower generation model. This model was developed in-house to model energy generation for projects where daily or weekly storage is available or without reservoir storage (i.e., run-of-river operation). The model is MS Excel-based and incorporates considerable functionality using macros for specific calculations. The model estimates energy generation in up to two peak periods and one off-peak period using the storage and the daily flow hydrology available and incorporates any flow constraints (e.g., bypass flows, ecological flows, etc) set by the user. The model can handle constant or variable station efficiencies and tailwater conditions, constant or variable head losses and seasonal variations in bypass flow and head-pond levels. In addition, the model can also handle seasonal constraints on installed capacity.

Energy estimates of the four schemes were evaluated in order to determine the benefits of plant generation with daily peaking if there was a reservoir storage formed by the diversion dams or in those cases where there is negligible storage and generation is on a run-of-river operation. Energy benefits were valued at $0.33 to $0.38/MWh based on an estimate of displaced diesel generation costs.

7.2 Model Inputs and Operation

7.2.1 Assumptions

Some assumptions and simplifications were made to the inputs of the power and energy model. These are described below:

- The minimum plant flow is between 30% to 40% of the rated flow of a single unit;
- The tailwater levels at the hydro sites are constant;
- The head loss coefficient (k) was calculated for the design flow of the plant or one unit when these are twin penstocks. The relationship head loss = k (turbine flow^2) is valid for flows less than or greater than the rated flow;
- The generator efficiency was set at 97.5%; the transformer efficiency was set at 98.5%;

- No transmission losses and station service factor are included in the energy calculations; and
- Plant availability is 100% (i.e., no forced outages are included in the energy estimates).

7.2.2 *Headpond / Reservoir Capacity Details*

Six out of eleven sites studied during Phase 1 would have headponds where the estimated surface areas varied between 0.05 km^2 (Site MK S-2) and 25 km^2 (Site 5). Two of the six sites were eliminated and are not in the preferred sites being studied at Phase 2. The Phase 1 assessment is considered very approximate and was based on the 1:50,000 mapping. Based on the Phase 2 analysis of the new mapping data, the revised surface areas and active storage volumes estimated for Site 11, Site MK S-2, Site 8C and Site ALX are as indicated in Table 7-1.

Table 7-1: Estimated Headpond Live Storage Volumes at Hydro Sites

Site No.	MAF (m^3/s)	MAF Volume (m^3) x 10^6	Design Flow of Plant (m^3/s)	Estimated Headpond Area (km^2)	Est. Live Storage (m^3) x 10^6 *a/*	Storage as % MAF (m^3)
11	125	3942.0	18.0	3.967	4.602	0.12%
MK S-2	1.6	50.5	1.5	0.013	0.001	0.00%
8C	61	1923.7	29.7	0.288	0.216	0.01%
ALX	52	1639.9	57.6	0.063	0.000	0.00%

Notes: a/ live storage volume not adjusted for winter ice cover.

Table 7-1 shows that Site 11 headpond would have a live storage of 4.6 million cubic metres (MCM) which reduces to approximately 3.41 MCM during winter. This is more than adequate for a peaking reservoir at Site 11 design flow. However, because of the favourable flow regime in the river, this site does not have a shortfall of run-of-river generation during the low flow months. Energy demand is met 100% of the time in these months; hence there is no need for peak loading generation.

Creation of a reservoir by raising the proposed dam at MK S-2 is not feasible because of the low flows and ice conditions in the winter.

The other site with a headpond is Site 8C with its live storage at 216,000 m^3 without an ice cover. This storage of 216,000 m^3 reduces to 129,600 m^3 with a 0.3 m thick ice cover during winter. Based on a run-of-river operation during the low flow months of January to April, Site 8C generated an average minimum energy of 19,769 kWh/day. At a minimum flow of 5.0 m^3/s the generated energy would be reduced to 14,960 kWh/day. The minimum turbineable flow of one unit at Site 8C is 4.5 m^3/s. An assessment of daily peaking generation with one unit (rated flow of 14.9 m^3/s) and a minimum river flow of 5.0 m^3/s during these months indicated that Site 8C headpond would allow peaking for 5.12 h at an output of 2205 kW. This would be an equivalent of 11,289 kWh/day or 350 MWh/month compared with a run-of-river (base load)

operation yielding 464 MWh/month but at 623 KW continuously. Because of the small size of 8C headpond live storage during the winter months, the peaking operation would generate less energy than the run-of-river operation over the same period but would deliver this at a higher load (2205 kW) for only 5.12 hours and no generation for 18.88 hours. If Site 8C reservoir was much larger then it would be possible to have longer peak generation periods as well as some off-peak generation.

Heightening of the dam/overflow spillway at Site ALX to create a larger reservoir is not practical/possible due to site topography.

In the absence of detailed load-demand data and daily load factors for the service communities, a detailed assessment of how the hydro plants would be dispatched was not undertaken but the Phase 2 designed plants are capable of adjusting their power output to match demand. Since there is no value differential for peak and off-peak energy, the better option would be to adopt a generation that delivers more daily energy which would be run-of-river generation. Because of the variability of flow at Site 8C, hydro generation does not provide a full displacement of diesel plants and these will be required to operate during the winter months but at a much reduced capacity.

7.2.3 Hydraulic Losses

Hydraulic losses were estimated for the water conveyance systems of the proposed hydro development layout. All four sites have pressurized water conductors and head losses were estimated for both non-pressurized and pressurized sections of the proposed schemes.

The most common head losses in the non-pressurized elements are associated with friction, transitions, bends, trashracks and intake structure configuration. Intake losses were calculated by a coefficient multiplied by the intake conduit velocity head. The coefficient varied according to the intake configuration/shape. Trash rack losses were based on a 40% blockage of the intake structure entrance area where trash racks are located accounting for steel fabrication and some trash blockage. Hydraulic friction head losses in the pressurized low-pressure pipelines and penstocks were calculated with the Darcy-Weisbach (D-W) equation. The friction factor “f” in the D-W equation was determined from the Stanton-Moody diagram for a relative roughness height of 0.50 to 0.6 mm for coated steel and 0.029 mm for glass reinforced fibre pipes and took into account some long-term aging effects of the pipes (slime, chemical deposits, etc).

Minor losses include those from bends in the pipelines and penstocks, transition sections in the water conductors, bifurcations,in the case of single penstocks branching to two turbine units and valves.

The estimated total head losses corresponding to the design flows of the water conductors for the four sites are given in Table 7-2.

Table 7-2: Hydraulic Losses in Sites

Parameter	Site 11	Site MK S-2	Site 8C	Site ALX
Total IC, kW	1500	1000	4400	4400
Type of unit	V. Kaplan	Hor Francis *a/*	V. Kaplan	V. Kaplan
No. of Units/PH	2	2	2	2
FSL, m	20	130	33.5	45
TWL, m	10	49.37	15.5	35
Hgross, m	10	80.63	18	10
Hnet, m	9.53	74.39	16.95	8.75
Est. Hydraulic Losses, m *b/*	0.47	6.24	1.05	1.25
Design Flow, m^3/s	18.0	1.5	29.7	57.6
Design Flow/unit, m^3/s	9.0	0.8	14.9	28.8

Notes:
a/ Single runner units
b/ Estimated for the design flow/unit with twin water conductors except at Site MK S-2

The estimation of hydraulic losses for flows greater or less than the design flows were prorated using a coefficient that relates head loss to flow according to the relationship provided in Section 7.2.1 - Assumptions.

7.2.4 Turbine-Generator Information

The hydraulic data used for the selection and sizing of the turbine generator units for the selected Phase 2 hydro project sites studies are shown in Table 7-2.

7.2.4.1 Type of Turbine

Low Head Sites

A vertical Kaplan turbine is proposed as the preferred type of turbine for low head sites – Site 11, Site 8C and Site ALX which have gross heads of 10, 18 and 10 m, respectively.

For the low head sites, three of the seven budgetary quotations received from manufacturers are with vertical units, the remaining are different types of horizontal units. The horizontal units proposed are generally with the turbine centre line setting below the tailwater level. With a horizontal arrangement of the units, the generator, gearboxes (if applicable) and many of the auxiliaries will be located below the tailwater level and hence will be at risk of flooding. In a vertical turbine arrangement the generator, control-metering-switchgear panels and many of the powerhouse electrical and mechanical equipment will be located on the powerhouse generator floor. The elevation of generator floor will be set above the maximum tailwater level.

The electrical power requirement for the communities near these sites is currently being served by diesel generator sets. The proposed small hydro generating units are therefore required to operate in an island mode with existing diesel generator units and also displace the diesel generated power to the maximum extent possible with available hydro potential.

Vertical turbines with low speed direct driven synchronous generators will provide the much needed higher inertia for stable operation of units, as compared to gear box driven high speed generators. Therefore gear box drives are not recommended. Additional inertia if required can be more readily incorporated in a vertical generator than in the case of horizontal generator.

A double regulated Kaplan turbine is capable of handling minimum flows down to 20% of the rated flows enabling maximum utilization of available low flows.

Site 11, 8C and ALX will have short penstocks with circular cross section whereas the full spiral casings for turbines are expected to be formed in concrete with trapezoidal sections. The transition piece (from circular unit penstock to rectangular spiral inlet) will be located downstream of the turbine inlet valves.

Medium Head Site

A horizontal Francis turbine is proposed as the preferred type of turbine for Makkovik Site MK S-2 which has a gross head of about 81.0 m. Seven out of the eight budgetary proposals received from turbine manufacturers are with horizontal Francis turbines. Small Francis turbines are commonly designed with runner mounted on generator shaft extension with the turbine generator fully assembled in the manufacturers shop and transported to site enabling quick installation. The turbine centerline is expected to set well above the tailwater level.

Number of Units

Based on the flow duration curve, the choice of one or two unit configuration for the powerhouse will be based on the minimum flows that may be required to pass through turbine/s for maximum utilization of available flows. The generator outputs for the selected project sites are well within the recognized capacity range of small hydro turbines. Double regulated Kaplan/axial flow turbines are capable of effectively handling flows down to 20% of the rated flows with relatively high part-load efficiencies. Therefore with a two unit configuration, the minimum flow capability will be 10% of the plant design flow.

Manufacturers provide standardized designs for low head small hydro turbines for the head range of 3 to 30 m and feature inherent robust designs in comparison to the customized designs for large hydro turbines. Therefore low head double regulated turbines can handle minimum flows in a much more stable manner unlike large low head turbines which may require air admission during part-load operation to minimize flow instability and associated vibrations.

Accordingly, the choice of one or two unit configuration for the powerhouses is decided based on the minimum flows to be handled and a comparison of the optimized annual energy generation and associated cost of construction. Based on past studies and experience, for sites with large flow variation, it has been established that the benefit to cost ratio of a two unit powerhouse is higher than that with one unit. In a two unit configuration, if one unit develops mechanical or other operation problems requiring a shut down, the availability of units is reduced to 50% whereas with a one unit configuration the availability reduces to zero. Single unit configuration for the given head and output will require a slower speed turbine requiring a speed increasing gear box in order to reduce the cost of generation thereby reducing the net effective generation efficiency. The two unit configuration will provide a relatively higher turbine speed, enabling a direct driven generator and hence higher net generation efficiency.

Francis turbines at the proposed Makkovik Site MK S-2 are capable of handling minimum flows of 35 to 40% of rated flows or 20% of plant design flow. Unlike the Kaplan turbine a Francis turbine will have relatively lower part-load efficiencies.

A two unit configuration of powerhouse design is therefore recommended for the selected projects.

7.2.4.2 *Efficiencies of Turbine and Generators*

The typical efficiencies of a Vertical Kaplan turbine, Synchronous Generator and unit (turbine and generator combined) for the low head sites are shown in Figure 7-1.

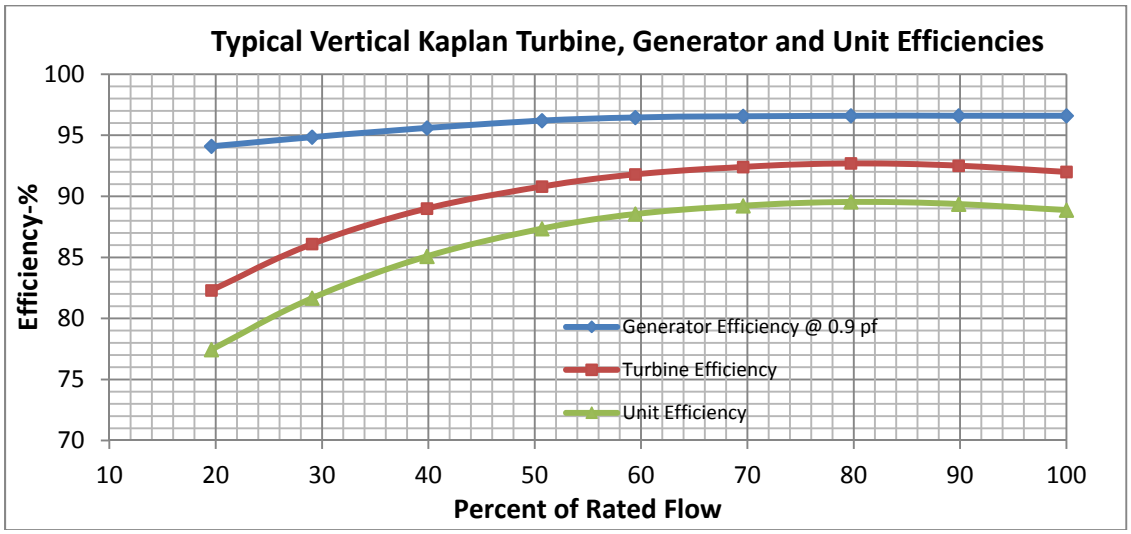


Figure 7-1: Typical Vertical Kaplan Turbine, Generator and Unit Efficiencies

The typical efficiencies of a small Francis turbine, Synchronous Generator and unit (turbine and generator combined) for Site MK S-2 are shown in Figure 7-2.

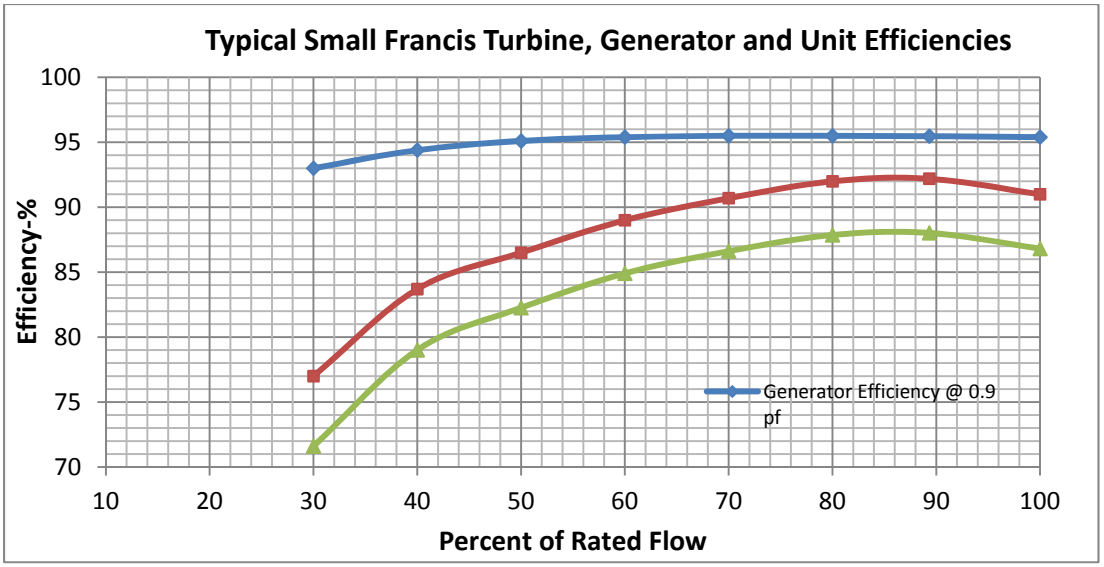


Figure 7-2: Typical Small Francis Turbine, Generator and Unit Efficiencies

Turbine unit efficiency curves were supplied by manufacturers in their quotations for electrical and mechanical generating equipment for Site 11, Site MK S-2, Site 8 and Site ALX based on hydraulic parameters of these sites that were supplied by Hatch. The manufacturer turbine efficiency curves were for single turbine units and these were convoluted into two-unit efficiency curves that when dispatched would maximized power from the two units. A resulting typical plant efficiency curve is shown in Figure 7-3.

The two-unit turbine efficiency curves were adjusted to account for both generator and transformer efficiencies. The generator efficiency was assumed to be equal to 97.5% and the transformer efficiency to 98.5%. Energy generation was estimated at the high tension side of the transformer and additional plant losses and transmission line losses were not considered. Generation losses for station service losses and scheduled and unscheduled outages were not accounted for in the annual generation.

In general terms, the turbine efficiencies at rated flow were approximately 92% for the proposed horizontal Francis units and 92.5% for the vertical Kaplan units. As typical of Kaplan units, the efficiency curve is relatively flat between the range of 60% rated flow and 100% rated flow. These high water conversion efficiencies (i.e., how well the turbine generator converts the power of falling water into electric power) are usual from the newer hydroplants being proposed for the hydro sites. The turbines/generators for the proposed four sites have been selected on the basis of reliable dispatchability since power output will need to be adjusted to match demand. In addition, all plants have two units which provide great

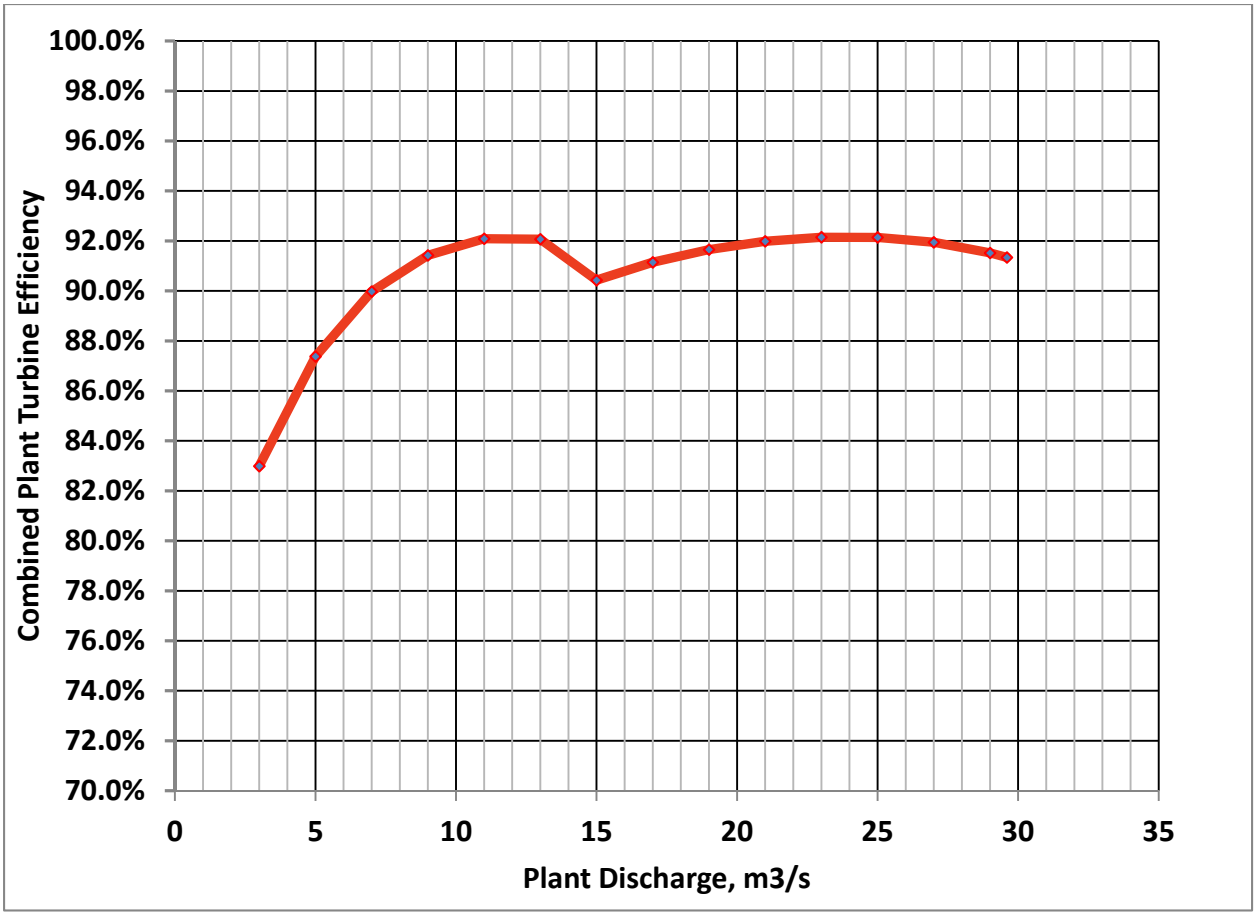


Figure 7-3: Site 8C Twin-Unit Turbine Combined Efficiency Curve

flexibility in generating at low flows. Electricity generation can be increased or cut back at the request of operators of the isolated systems. Since these are hydro plants, the dispatchable generation can be turned on or off or varied in time frames of minutes or can engage in load matching (slow changes in power demand), peak matching and lead-in times. The hydro power plants will have a governing system that will allow each plant to respond to changing load demands without supplementary diesel generation. The generators cannot operate in asynchronous mode because they will be operating in isolated grid systems.

7.2.5 Bypass and Compensation Flows

The environmental bypass flow was estimated from the site visit and previous experience with similar plants on other river systems. It is not expected that the bypass flows will be larger during the summer daytime hours due to aesthetic requirements since there are no scenic waterfalls at either of the four sites. In the absence of detailed environmental screening and Agency consultation, and because there is minimal competition for water at the sites, the Montana method by Tennant, which is applicable in cases where there is minimal competition for water, was used to make a preliminary assessment of instream flows. This method resulted in the adoption of criteria to set the bypass flow equal to 10% of the lowest of the average monthly flows during any particular month. These bypass flow values were assumed and since these are not turbinable, they are deducted from the river flows used in the energy simulations. Energy estimates were calculated for the conditions of “with” and “without” bypass flows to show the differences in energy estimates between the two conditions. The energy estimates “without” bypass flows are subsequently used as the input to the economic analysis. Bypass flows are usually subject to agency input later in the environmental screening assessment process of the proposed development hydro site(s) and are finalized at that stage.

7.2.6 Energy Generation Simulation – Base Load

The energy simulation consisted of calculating daily energy from each site’s simulated daily flows over 33 years (1979 to 2011) and the plant characteristics for each of the sites. In order to obtain a 50-year period of energy estimates from the hydrological sequence, the annual energy amounts for the first 17 years of the series were appended to the 33-year sequence. A moving means plot in the Phase 1 report demonstrated that the first 17 years of the hydrological series varied from slightly above average climatic years to below average climatic years with more years exhibiting flows that were below average. Appending the 17-year energy sequence as described above is therefore conservative from a generation perspective (i.e., the energy values would be more representative of dry years and not wet or average years.) The resulting daily energy was then aggregated into monthly and annual energy amounts.

7.3 Energy Generation Estimates

The annual energy generation for the four sites are summarized in Table 7- 3. Detailed tables with monthly generation for the 33-year period can be found in Tables E-1 to E-10, Appendix E.

Table 7-3: Average Annual Energy Potential for Sites Without Reservoir Storage

Site	Design Flow (m^3/s)	Net Head (m)	Inst. Capacity (MW)	Capacity Factor (%)	Mean Annual Potential Generation *a/* (MWh)
Site 11	18	9.53	1.50	93	12,248
Site MK S-2	1.5	74.4	1.00	45	3,902
Site 8C	29.7	16.95	4.40	74	28,544
Site ALX	57.6	8.75	4.40	47	18,057

Notes:
a/ Based on 1979-2010 measured flow sequence. Does not include contingency for bypass flow and assumes 24-hour generation at continuous load and run-of-river operation.

The percentage differences between the energy estimates "without" bypass flows and "with" bypass flows were small and varied between 0.7% at Site 11 to 3.4% at Site ALX. Because the criteria for establishing bypass flows has not been established, energy estimates calculated for the "without" bypass flows at each site were used as the potential energy generation at the respective sites.

7.4 Power and Energy Utilization

Based on the results of the energy generation model for the four sites and the forecasted energy demand (2037) at each site, an evaluation of energy utilization on a monthly basis was performed. Its purpose was to determine how generation met demand due to the variations of flow in the hydrological flow sequences. In general, the potential generated energy will exceed the demand energy at the sites since the demand for power varies continuously. The load factor on a daily basis may be about 0.70 to 0.80 but the site capacity was sized on peak demand. Energy demand on a monthly basis was based on the current energy demand pattern for the respective communities.

Site 11 and Site 8C performed the best in meeting the 2037 monthly energy demand. Site 11 with a capacity factor (CF) of 93%, met demand in all months of the year. Table E-11 in Appendix E summarizes the results of energy demand and potential generation. Since demand is satisfied in all months there would be no need for supplementary diesel generation although existing diesel generating plants may need to be retained as stand-by facilities.

Site MK S-2 had the poorest utilization and generation in the winter months, only meeting between 0% and 15% of demand during 5 months. For the remaining 7 months, generation was met 49% to 100%. Energy demand was only satisfied in the month of June. Supplemental diesel generation at this site would amount to 50% of demand. The details are given in Table E-12 of Appendix E.

Generation at Site 8C has a CF of 74% and would meet demand in 9 months of a year while in the months of January, February and March demand was satisfied between 53% and 66% on a monthly basis. Overall, 88% of demanded energy was supplied and the shortfall to be met from diesel generation is 12%. A breakdown of the utilization is given in Table E-13 in Appendix E.

Site ALX satisfied 56% of its forecasted annual energy demand and fully met demand in May. Table E-14 in Appendix E gives the monthly utilization and expected deficits that must be made up by diesel generation. The CF of Site ALX is 47% and during the winter months low flows fall below the minimum turbineable flow of the proposed plant. The results of energy utilization and short-fall on an annual basis are provided in Table 7-4.

Figures 7-4 to 7-6 show the energy demand and expected plant generation on an average monthly basis and indicate the months in which diesel generation will be required.

Table 7-4: Annual Energy Hydro Site Generation, Defecits and Diesel Generation

Site	Annual Energy Demand *a/* (MWh)	Mean Annual Potential Generation (MWh)	Surplus Energy *b/* (MWh)	Hydro Site Generation *c/* (MWh)	% of Demand Satisfied by Hydro Generation (%)	Energy Shortfall (MWh)	% of Demand Satisfied by Diesel Generation (%)
11	9,538	12,248	2,710	9,538	100%	0	0%
MK S-2	7,259	3,902	258	3,644	50%	3,615	50%
8C	31,717	28,544	737	27,807	88%	3,911	12%
ALX	31,717	18,057	381	17,676	56%	14,042	44%

Notes:
a/ Peak load duration is assumed to be 24 hours.
b/ Surplus energy occurs when monthly potential energy exceeds monthly demand.
c/ Hydro site generation is the difference between annual potential generation and surplus energy.

7.4.1 Comparison of Energy Demand and Potential Generation

A comparison was made between the annual forecasted energy demand for CHT/PHS/MSH and the annual potential site generation of both Site 8C and Site ALX. For the purposes of this comparison, an aggregated monthly load curve for Sites 8C and ALX was established by summing 2008 monthly load curves for Charlottetown, Port Hope Simpson and Mary's Harbour. The load curves were provided in NL Hydro's 2009 report: Preliminary Assessment of Alternative Energy Potential in Coastal Labrador (Reference 7).

The aggregated load curve was normalized and prorated based on the projected peak demand load of the three communities for each year. Monthly energy was calculated as the product of the number of hours in each month and the corresponding projected peak load during that month. That is, it was assumed that the monthly peak load occurs for 24 hours each day. The annual demand energy was calculated as the sum of the monthly energy. Since this is an aggregated total, there are several months in a year when the energy demand is less than the annual generation. Generated energy at the respective sites was estimated by the power and energy model using the respective simulated hydrological flow sequences. The hydrological flows were extended beyond 2045 to obtain generated energy over 50 years.

Figure 7-7 shows the comparison of annual forecasted energy demand and annual potential site generation from Site 8C and Site ALX. Generation and demand are superimposed in the figure to start in 2012 but in reality generation at either site may not commence before the station is constructed at earliest in 2016. The variable amount of annual generated energy is directly related to the hydrological flows at each site.

When compared to the annual demand, energy generated at Site 8C exceeds this amount in about 7 years. The assumption of using its generated energy stream as input to the economic analysis does not introduce any significant errors because of excess energy which is not utilized. The calculated energy utilization for Site 8C is 88%. In the case of Site ALX, its annual generation satisfies about 56% of demand annually.

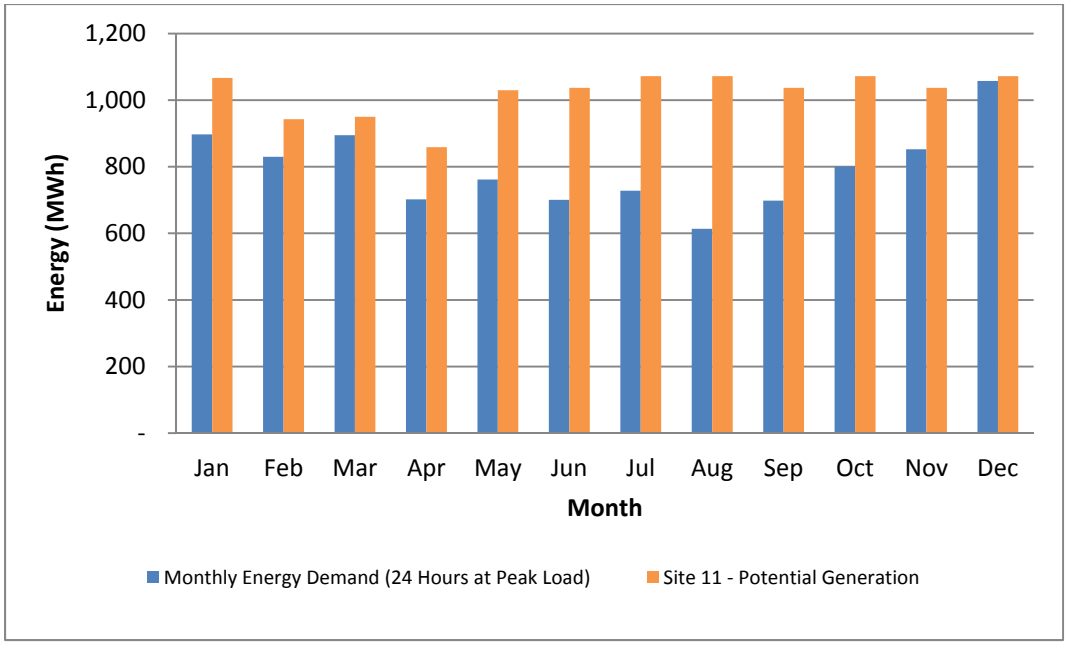


Figure 7-4: Projected Energy Demand (2037) and Generation Site Serving Hopedale

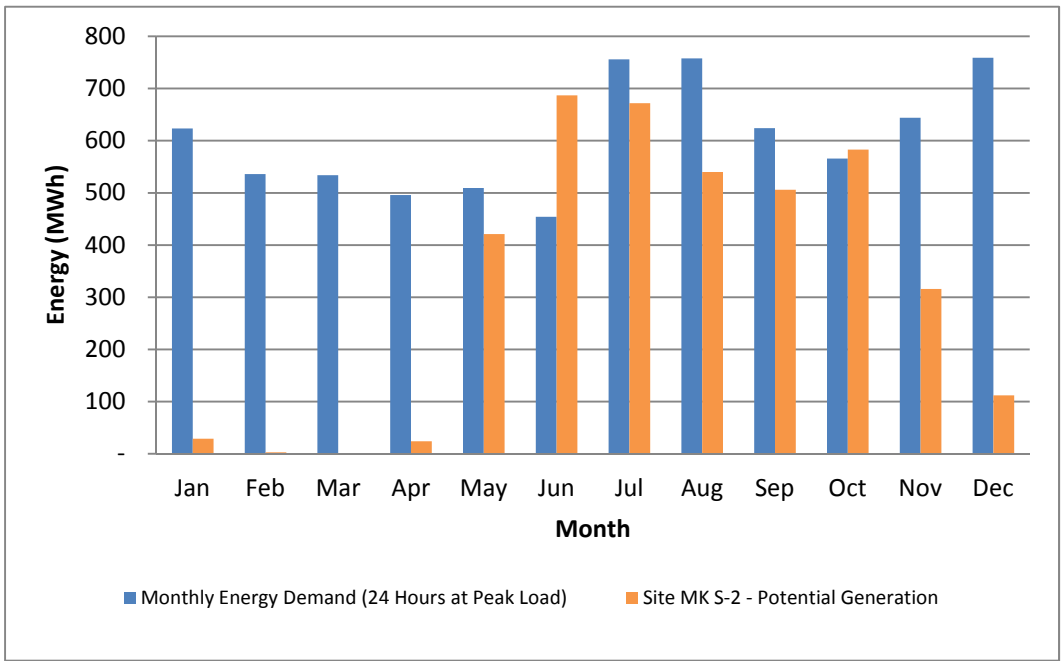


Figure 7-5: Projected Energy Demand (2037) and Generation Site Serving Makkovik

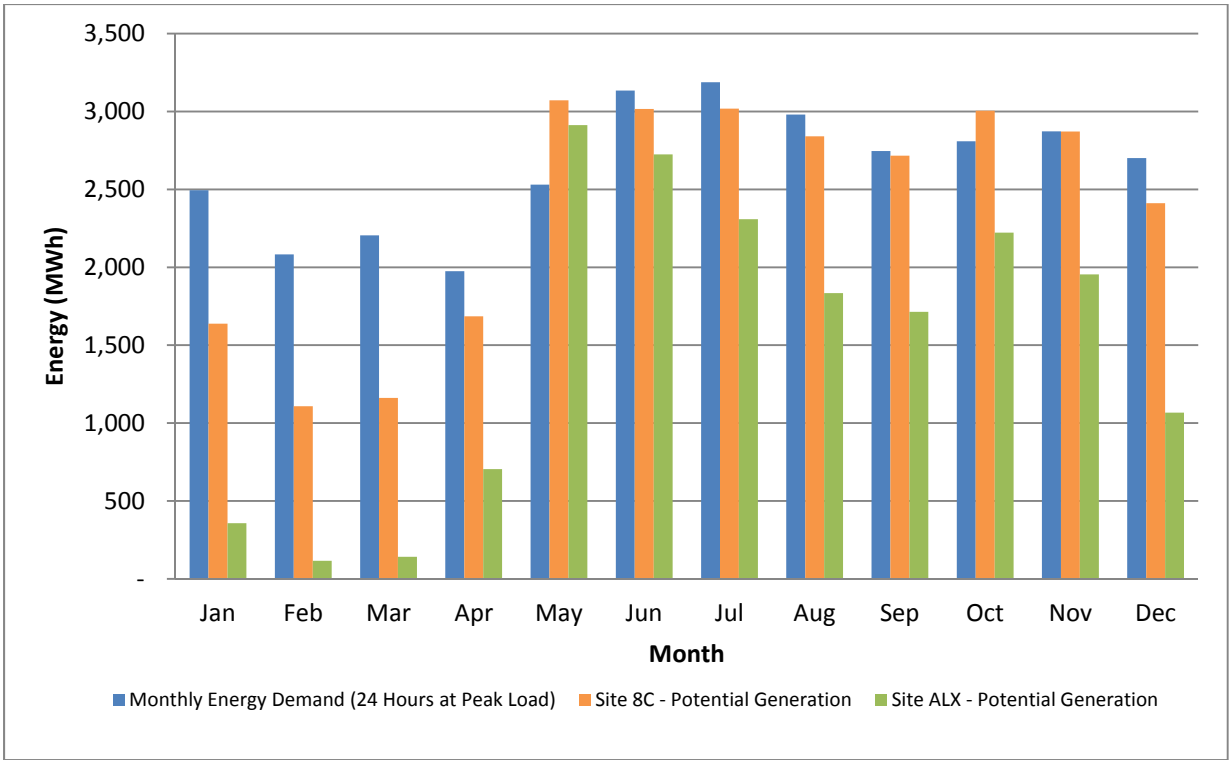


Figure 7-6: Projected Energy Demand (2037) and Generation
Sites Serving Charlottetown, Port Hope Simpson and Mary's Harbour

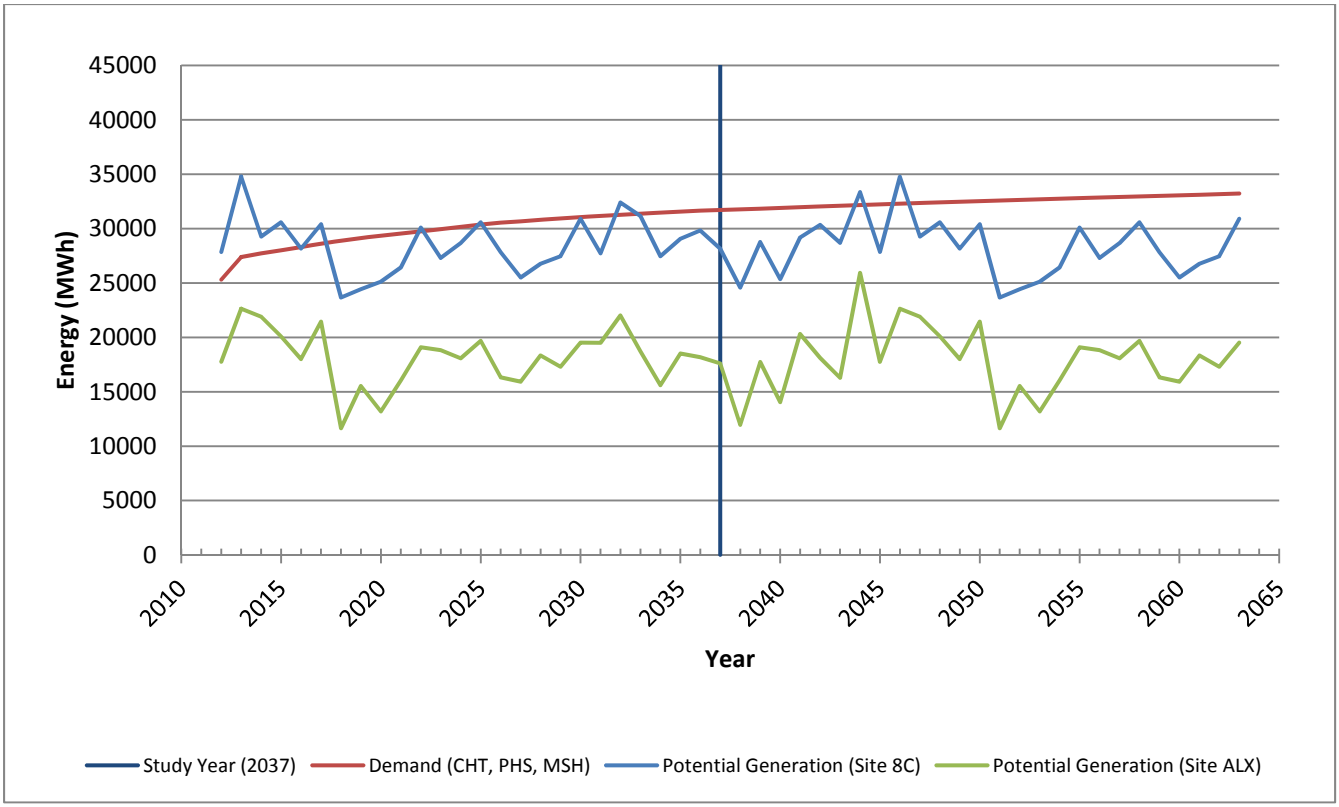


Figure 7-7: Comparison of Annual Energy Demand and Potential Site Generation Sites Serving Charlottetown, Port Hope Simpson and Mary's Harbour

8. Cost Estimates

8.1 General

Cost estimates were prepared for each of the four (4) selected sites.

These estimates are generally based on the following engineering inputs:

- general arrangement drawings
- intake, powerhouse and spillway drawings
- geotechnical considerations
- hydrotechnical studies
- optimization studies for turbine and generator equipment
- procurement strategy identifying long lead items for equipment.

The cost estimates are classified as Association for the Advancement of Cost Engineering (AACE) Class 3 level estimates. The predicted accuracy range of these estimates is -5% to -20% on the low side, and +10% to +30% on the high side. The level of contingency overall is 15 to 20%.

8.2 Basis of Estimate

It is assumed the projects will be structured under an Engineering, Procurement and Construction Management (EPCM) project delivery method and can be constructed using local Newfoundland and Labrador contractors and local labour to the fullest extent possible.

The cost estimates were compiled based on the following parameters:

- Obtaining budget quotations from generating equipment suppliers from Canada and overseas for the selected sites, and developing a cost curve for all proposed capacities.
- Assessing Hatch's database for ancillary/balance of plant (BOP) mechanical and electrical equipment pricing for recent similar projects.
- Estimated installation and commissioning costs for major mechanical/electrical equipment as well as for BOP equipment based on Hatch database benchmarks from hydroelectric projects.
- Applying basic quantities and all-inclusive unit prices as appropriate at this level of the study.
- The unit prices for all works developed using Hatch proprietary estimating database/ software "Candy".
- Unit prices are deemed to include all expenses incurred for each specific construction activity and include construction labour, construction plant and material, and Contractors' overhead and profit.

- Labour rates used in “Candy” are based on current labour agreements applicable to the 2012 market environment in Newfoundland and Labrador.
- Construction plant and equipment rates are based on contractors’ leasing of equipment due to the present heavy schedule of projects in the province.
- Bulk materials costs are based on the nature and source of the materials to be included in the construction. Basically, two categories exist: material produced at the site, material purchased from the outside sources.

All costs are in October 2012 Canadian Dollars.

8.3 Estimate Methodology

8.3.1 Estimate Approach

When preparing these estimates the following aspects were considered and addressed:

- Defined scope of work
- Coding and structuring the project into a Work Breakdown Structure (WBS) / Estimate Breakdown Structure (EBS)
- Quantify the works in accordance with the drawings
- Location of the sites
- Site conditions
- Labour productivity in the present environment
- Labour source
- Equipment budget quotations
- Collect actual bid prices by contractors on other similar projects
- Collect and review historical cost database
- Solicit budget quotations for turbine/generator
- Develop labour man-hour rates for the construction work
- Constructability issues
- Safety and Environmental considerations
- Project schedules
- Establishing appropriate contingencies

A summary of the basis of the estimates is provided in Table 8-1.

Table 8-1: Summary of Basis of Estimates

Commodity	Estimate Basis
Plant and Equipment	
Major Equipment Supply Cost (Turbine and Generator)	Estimates for major generating equipment (*Turbines, Governor, HPU units, Generator with excitation and Speed Increaser for 2 units*) are based on budget quotations received from manufacturers based on project-specific specifications and data sheets. The following manufacturers provided quotations: *CHC, Mavel, Mecamidi, Norcan, Andritz, Ossberger, Siemens and Voith.*
Minor Equipment [Balance of Plant (BOP) mechanical and electrical equipment and hydro mechanical equipment]	Wherever possible and for many minor items, budget quotations were derived from vendor's quotations using project-specific specifications and data sheets. Auxiliary Electrical Systems have been included in manufacturers' quotations (control, protection, metering, MV switchgear. Station AC and DC services). Additional pricing data for minor equipment and materials was obtained from in-house database, empirical equations and/or costs from other similar projects.
Freight	Quotations used for the estimate include delivery to nearest port in Labrador. The cost of transport to the site was added.
Installation	
Major and BOP Equipment Installation Cost	Installation costs for the permanent equipment were estimated by using historical data from Hatch's project database or applicable labour input data from the 2012 Means publication. For all major equipment items, the installation cost includes costs for equipment testing and commissioning.
Bulk Materials and Site Works	
Site Works (Site Preparation and Earthworks)	Material take-offs (MTOs) were developed from preliminary drawings and sketches. Unit rates were determined by first principal analysis method, labour and equipment rate from Hatch database on energy sector.
Concrete	MTOs were developed from preliminary drawings and sketches. Prices were based on calculation for site production, including the cost for batching, processing, and additives.
Structural Steelwork / Superstructure	This work generally consists of the powerhouse superstructure which is measured by volume (m^3, air space inside of powerhouse) as developed from sketches. The unit rate was obtained from similar projects.
Piping, Valves and Fittings	Hatch database on similar projects
Switchyard Equipment	Based on equipment lists and Hatch database prices
Instrumentation & Control Systems	Prices from similar projects
Transmission Lines	Budget prices obtained from contractors for similar projects
Construction Labour	Labour rates are based on the latest union agreement
Construction Equipment	Rates were based on equipment costs from the Hatch database. Equipment hours were based on the installation schedule and estimated installation hours. Equipment rates have been adjusted to lease rates of 36 months.
Indirect Costs and Northern Factor	
Contractor Mobilization and Demobilization	This is the cost for mobilization and de-mobilization in the cost estimate, considering mobilization and demobilization of construction equipment, erection of all construction plant. No detailed analysis was done for this item; the amount allocated was compared to similar previous projects.
Construction Camp	Cost for construction camps (installation & operating expenses and catering cost) or subsistence costs are addressed in the estimate as a percentage cost based on Hatch benchmarks data from similar project and similar project locations.

Commodity	Estimate Basis
EPCM Cost	Estimate based on 7.5% of the Total Estimated Construction Cost.
Contractor Indirects	Estimate based on developed construction schedules and labour rates. Contractor mark-up and profit is included in the unit rates.

8.4 Structure of the Cost Estimates

The project cost estimates have been structured using the following estimate categories:

- direct cost (civil & electrical/mechanical)
- contractors' indirect costs (as a percentage of the direct costs, covering construction facilities, camps/subsistence and a Northern Factor)
- contingencies (% of all above)
- (EPCM) environmental, engineering, administration and construction management by the Owner's Engineering company (% of above).

8.5 Direct Cost

8.5.1 Civil Works Direct Costs

The overall civil work construction estimated costs were broken down into the following structures/components based on their purpose and construction methodology.

- **Borrow Areas**

  Low potential for till materials on some sites. Sand and gravel potential are at streams and shorelines. Rockfill can be found at all locations and would be easily obtained.

- **Project Access Roads**

  Cost of the new access roads to the sites and borrow areas include road base preparation, granular subbase and base course, width of 6 m and road ditch alongside. Recognizing land contours, rockfill materials are foreseen to be incorporated in the road body.

- **Cofferdams and Embankment Dams**

  The body of all main dams consists of blasted rock fill, cut-off wall, granular / transition materials (sand and filter) and riprap on the upstream face. Construction crews are required for excavation equipment (borrow area), haulage fleet and spreading, and compaction equipment and labour. Rock fill and granular materials will be placed in lifts and compacted with passes of a pneumatic roller.

- **Cut-off-Walls**

  Installation of cut-off walls (example: cement/bentonite slurry wall) will be undertaken by a specialized subcontractor. The unit cost includes subcontractor's mobilization and

demobilization, building of slurry ponds, set-up pumps, excavate trench, batch, and deliver and place slurry.

- **Intake and Powerhouse Structures**

  Excavated material of a suitable quality will be re-used in access roads and for temporary structures where required. Drill and blast method will be employed for the rock excavation. Drilling of perimeter holes for all structural rock excavation. Excavation rock will be used in construction of the main dams. Structures are backfilled with suitable granular fill. It is assumed that all horizontal and vertical rock surfaces will be machine cleaned and scaled prior to concrete placement. All horizontal surfaces under the intakes, powerhouses and bypass structure slabs will be cleaned, mainly by hand. All concrete will be batched at the site batch plant and will be delivered to the structure by concrete transit mixer or directly by crane and bucket. All concrete placed in base slabs is poured against rock faces. No formwork is required. All concrete/formwork and rebar installation will be by mobile crane and concrete pumps will be used for placing. All structural concrete is 30 mPa compressive strength. Allowances for concrete heating and hoarding costs have been included in the cost estimate. A reinforcement ratio of 60 to 70 kg/m^3 of concrete is assumed for all concrete structures.

8.5.2 Electrical/Mechanical Direct Costs

Major electrical/mechanical hydraulic equipment includes:

- water-to-wire (W2W) equipment (turbines and governors, generators and exciters)
- unit transformers and switching equipment
- hydraulic equipment (gates, hoists, stop logs and trashracks)
- BOP mechanical equipment and services
- BOP electrical equipment and services (switchgear, AC/DC, SCADA)

All equipment pricing in the estimate was reviewed to ensure that the following criteria were addressed, and taken into consideration where necessary:

- Allowance for attendance by vendor representatives.
- A cost for commissioning spare parts would be included in the estimate where applicable.
- Freight and packaging.
- Electromechanical costs were estimated according to the following criteria:
  - two unit powerhouses
  - unitized scheme with one transformer for each unit for reliability and operational reasons

- all transmission and interconnection to be assumed to be at 34.5/25 kV with generator voltage at 13.8 kV
- no local power distribution lines/equipment are included (water control structures requiring power are assumed to be within a short distance of the respective powerhouses and an allowance for this interconnection has been provided in the estimate
  - the transmission line unit price is based on a per km basis, single circuit on 34.5/25-kV wood poles
  - unloading, storage and hoisting E&M equipment has been included
  - dedicated penstocks where shown are provided to each powerhouse in order to provide operational and maintenance flexibility.

- Transformers and switchyard equipment and most of other electrical equipment will be handled by the mobile crane. A mobile crane would be required for unloading, storage (if required), and subsequent moving to point of installation for all E&M equipment. Installation and embedment of draft tube elbows would require a mobile crane as the powerhouse crane would not be available for this stage of construction.
- The unit price for supply and installation of the penstocks included in the estimate has been assumed based on Hatch database for the similar projects taking into account recent steel and fibreglass penstock quotations.

8.6 Construction Facilities, Indirect Costs and Labrador Factor

Applied in the estimate is 30% of the total civil & electrical/mechanical direct cost to cover the following contractors' expenses:

- site supervision
- survey and quality control expenses
- home office expenses, travel
- the Northern Factor - constructability and scheduling constraints assumed with project execution in a harsh northern climate
- site facilities expenses - costs are deemed to include rental and setup office trailer, lunch room trailer, and warehouse trailer; office supplies, cell phone or radio service, temporary power for trailers and yard, water, tower lights and sanitation services
- mobilization and demobilization of plant
- lay-down areas and temporary construction roads
- temporary construction camp (installation & operating expenses) or subsistence costs.

8.7 Contingencies

Contingencies are included in the estimate to provide for costs which cannot be specifically identified at the time of estimate preparation, and for the accuracy of the pricing.

Contingencies applied are:

- Civil works 20%
- Mechanical & Electrical Works 10%

8.8 Environmental, Engineering, Administration and Construction Management by the Owner's Engineering Company

For each project estimate, a lump sum amount equal to 7.5 percent of the total estimated construction cost has been added for the environmental assessment, engineering, procurement, administration and construction inspection by NL Hydro's engineering company.

8.9 Exclusions

Estimated costs are exclusive of: escalation beyond October 2012 price levels, HST, land acquisition, financing/IDC, and Owner's costs.

8.10 Summary of Estimated Costs

A summary of the estimated project costs and contingencies is provided in Table 8-2. The detailed cost estimates are provided as Figures 8-1, 8-2, 8-3 and 8-4 in Appendix F.

8.11 Cash Flows

Annual and cumulative cash flows for the four projects are provided in Figures 8-5, 8-6, 8-7 and 8-8 in Appendix F.

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Table 8-2: Summary of Estimated Costs

October, 2012

		Hopedale	Makkovik	CHT/PHS/MSH	
		Site 11	**MK S-2**	**Site 8C**	**ALX**
	Installed Capacity (kW)	1,500	1,000	4,400	4,400
	Net Head (m)	9.53	74.39	16.95	8.75
A - Civil Works					
1	Access	$490,000	$1,225,000	$1,750,000	$3,150,000
2	Cofferdams & Dewatering	$657,000	$171,000	$930,000	$630,000
3	Dams & Diversion	$913,750	$1,852,800	$6,553,600	$1,292,750
4	Spillways	$4,444,000	$983,000	$4,345,000	$2,135,000
5	Power Conveyance Pipe	$207,000	$2,850,000	$1,515,000	$2,488,000
6	Intake, Penstocks & Powerhouse	$5,204,500	$954,750	$10,582,000	$7,197,000
7	Fish Passage	$850,000	incl in (3)	$2,270,000	incl in (3)
	Sub-Total - Civil Works	**$12,766,250**	**$8,036,550**	**$27,945,600**	**$16,892,750**
B - Mechanical and Electrical Works					
1	Intake Gates & Hoists	$759,900	$163,000	$788,500	$1,246,500
2	Powerhouse (M & E)	$3,316,200	$2,566,400	$5,777,400	$5,911,000
3	Substation & Transmission Lines	$7,485,000	$1,510,000	$4,600,000	$8,840,000
	Sub-Total - Mechanical & Electrical Works	**$11,561,100**	**$4,239,400**	**$11,165,900**	**$15,997,500**
Subtotal A - Civil Works		$12,766,250	$8,036,550	$27,945,600	$16,892,750
Subtotal B - Mechanical & Electrical Works		$11,561,100	$4,239,400	$11,165,900	$15,997,500
Subtotal C - Construction Facilities, Indirect Cost & Labrador Factor		$7,298,200	$3,682,800	$11,733,500	$9,867,100
Subtotal Without Contingencies		**$31,625,550**	**$15,958,750**	**$50,845,000**	**$42,757,350**
Contingencies		**$3,709,410**	**$2,031,000**	**$6,705,690**	**$4,978,350**
Total Estimated Construction Cost		**$35,334,960**	**$17,989,750**	**$57,550,690**	**$47,735,700**
Environmental, Engineering and Construction Management		**$2,650,100**	**$1,350,000**	**$4,316,300**	**$3,580,200**
Total Estimated Project Cost		**$37,985,060**	**$19,339,750**	**$61,866,990**	**$51,315,900**
	Total Cost $/kW	***$25,300***	***$19,300***	***$14,100***	***$11,700***
Interconnection Cost CHT/PHS/MSH				***$9,375,000***	***$9,375,000***

Exclusions:

-escalation beyond October, 2012
- taxes
- land
- financing / IDC
- Owner's costs

9. Project Schedules

9.1 Structure and Assumptions

Project implementation schedules were developed using Microsoft Project Planner identifying a possible critical path for each of the four (4) potential projects. The schedules are provided in Appendix G, as follows:

- Figure 9-1: Site 11
- Figure 9-2: Site MK S-2
- Figure 9-3: Site 8C
- Figure 9-4: Site ALX

The activities in each schedule are grouped into three (3) main categories and subcategories based on the stages of project development, namely:

- ENVIRONMENTAL PROCESS
- ENGINEERING, DESIGN AND PROCUREMENT PHASE
  - Completion of FEL-3 - Project Definition Phase
  - FEL-4 Project Implementation Phase (Tendering, Detailed Design and Construction Drawings, Contracting, Design, Manufacture and Deliver Equipment)
- CONSTRUCTION & INSTALLATION
  - Civil Works
  - W2W Equipment, Substation and Transmission Line Installation

The schedules were prepared based on the following assumptions:

(i) ENVIRONMENTAL PROCESS – begin as soon as FEL-3 General Arrangement drawings are issued; work includes:

- Phase 1 - Aquatic and terrestrial field studies, public and agency consultation, impact statement, mitigation measures, assessment of residual effects, environmental management plan
- Phase 2 - Environmental Assessment (EA) Report Preparation - issue Draft Report for submission to agency for approval; and, Final Report, with input from public consultation.
- Publishing Notice of Completion (once EA approved) separately for each site implemented.
- Provincial and Federal Approvals (permitting process)

(ii) ENGINEERING, DESIGN AND PROCUREMENT – includes:

- Completion of FEL-3 phase, including design and drawings
- Phase FEL-4 : Implementation Phase, including: preparation of Tender Documents and issue for tender, tender evaluation and award for three (3) proposed contract packages, which will be:
- W2W Equipment Supply Contract,
- General/Civil Contract
- Balance of Plant M&E Supply Contract [hydro-mechanical, substation equipment and transmission line materials (poles, conductors)
- The work under the General/Civil Contract is deemed to include construction of contractor's site facilities, civil works, installation of the turbine/generator equipment, installation of balance of plant [BOP] mechanical/electrical equipment; and also includes design, supply and delivery of heavy mechanical equipment including the penstocks, and gates/guides/hoists.
- It is assumed the award of the General Contract would take place immediately upon receipt of the environmental approval.
- Award of the W2W package preceed award of the General Contract
- Award of the General Contract will proceed after firm W2W design is available.

(iii) CONSTRUCTION AND INSTALLATION

The work for the site construction is further divided into following components as per each specific project composition, which includes:

- Cofferdams and Diversion
- Spillways
- Intake and Approach Channels
- Dam Construction (rockfill, earthfill or concrete)
- Intake Structure
- Power Conveyance / Penstocks
- Powerhouse
- W2W & Mechanical and Electrical Installation and Testing and Commissioning
- Substation (Electrical Equipment)
- Transmission Line

9.1.1 Critical Path

Based on the analyses, the following works are located on the critical path of each project development schedule in accordance with above assumptions:

- Engineering and design, tendering and contract initiation, evaluation and awards (complete FEL-3; FEL-4 Engineering)
- Civil Works
  - Site 11 (Access Road, Cofferdams & Diversion Facilities, Powerhouse & Substation [Civil, W2W Erection, Testing & Commissioning of Turbine & Generator Units.]
  - Site MK S-2 (Access Road, Cofferdams & Diversion Facilities, Penstock of Powerhouse & Substation)
  - Site 8C (Access Road, Embankment Dam, Diversion and Fishway, Turbines/Generators Erection & Commissioning)
  - Site ALX (Access Road, Cofferdams & Diversion Facilities, Spillway, Dam Construction, Power Intake & Penstock, Powerhouse & Substation.

10. Environmental Considerations

10.1 Introduction

A desktop screening of environmental issues at 11 sites was previously conducted by Sikumiut Environmental Management Ltd. (Sikumiut) to support Hatch's review and Phase 1 Advanced Screening of small hydro potential for Coastal Labrador. Based on the outcome of the Advanced Screening, four sites were selected for Phase 2 – Project Definition Phase: two in northeastern Labrador near Hopedale (Site 11 – Adlatok River) and Makkovik (Site MK S-2 – Makkovik Brook), and two alternative sites in southeastern Labrador near Port Hope Simpson (Site ALX – Alexis River; and Site 8 – St. Lewis River).

Sikumiut has been engaged to determine whether a full Environmental Impact Statement (EIS) or an Environmental Preview Report (EPR) will likely be required for each of the four sites selected in Phase 2 for potential hydroelectric development.

Sikumiut has been asked to develop an Environmental Assessment (EA) strategy tailored to the unique features and settings of the four sites including a Draft Consultation Plan that considers all stakeholders and issues specific to this type of development in a Labrador setting.

10.2 Requirement of Environmental Impact Statement or Environmental Preview Report

Registration of an undertaking is required if reservoir creation exceeds 50 hectares, if powerhouse capacity exceeds 1 megawatt (MW), or if new transmission lines will be built more than 500m from an existing right of way (*Environmental Assessment Regulations, 2003* under the *Environmental Protection Act* (O.C. 2003-220)).

According to Table 10-1, all four potential hydroelectric power developments would need to be registered since they meet or exceed one more of the criterion set for project registration. Following registration, the Minister would decide if an Environmental Impact Statement (EIS) or an Environmental Preview Report (EPR) is required.

The Adlatok River and Makkovik Brook are salmon rivers and have no barriers to fish passage downstream of Site 11 (Adlatok River) and Site MK S-2 (Makkovik Brook). Furthermore, these two sites are with Labrador Inuit Lands (LIL) and will be subject to Labrador Inuit Land Claims Agreement (LILCA) and legislation under the Nunatsiavut Environmental Protection Act (Bill 2010-07). It is very likely that hydroelectric development at either of these sites will be subject to an Environmental Impact Statement.

Site ALX is on the Alexis River and Site 8 is on the St. Lewis River, both Class III Scheduled Salmon Rivers. There is only a partial barrier to fish passage located on each river downstream of the selected sites. It is very likely that an Environmental Impact Statement will be required for a hydroelectric development at either of these sites.

An annotated table of contents for a brief Project Description is included in Appendix H, for information.

Table 10-1: Features of Potential Hydroelectric Developments at Four Selected Sites in Coastal Labrador

Site No.	Approximate Headpond Area (m^2)	Approximate Headpond Area (hectares)	Installed Capacities of Powerhouses (MW)	Length of New Transmission Lines (km) to an Existing Right-of-Way
Site 11	3,970,000	397	1.5	45
Site MK S-2	13,000	1.3	1	7
Site ALX	62,700	6.3	4.4	18
Site 8	288,000	28.8	4.4	10

10.3 Ecological Issues and Requirements

Site 11 near Hopedale lies along the Adlatok River, which includes anadromous Atlantic salmon, ouananiche, brook trout, Arctic char, northern pike and longnose sucker. While this is not a scheduled river, it is still open to angling and is in fact one of Labrador's premiere salmon angling rivers; an outfitter operates near the proposed site. As this site is lower in the watershed, this area is likely used more for migratory purposes than rearing purposes (DFO, 2012).

Site MK S-2 is located along Makkovik Brook. Makkovik residents report a run of Atlantic salmon and trout (either Arctic char, brook trout or both) along Makkovik Brook. Again, while this is not a scheduled salmon river, it is open to angling.

Site ALX is located along the Alexis River, a Class III Scheduled Salmon River. Atlantic salmon and sea-run and resident brook trout are all reported to be present in the Alexis River. Site ALX lies only slightly upstream from a 10 m falls which acts as a partial fish passage barrier. There is another partial fish passage barrier 2.8 km upstream from Site ALX and a complete fish passage barrier 8.3 km upstream from Site ALX.

Site 8 is located along the St. Lewis River, a Class III Scheduled Salmon River. Atlantic salmon and trout parr are reported to be plentiful in the lower areas of the St. Lewis River while large quantities of smelt occur in St. Lewis Inlet. Approximately 17 km downstream of this site there are two sets of falls, both act as partial barriers to fish passage. As the site is lower in the watershed, this area is likely used more for migratory purposes than rearing purposes.

10.4 Labrador Inuit Land Claims Agreement

Much of northeastern Labrador is subject to the Labrador Inuit Land Claims Agreement and the Labrador Inuit Settlement Area occupies most of the area. Hopedale and Makkovik are the only areas for this study that are affected by Labrador Inuit Land Claims Agreement. Labrador Inuit Lands are lands owned by Inuit and are identified in the Labrador Inuit Land Claims Agreement. Specific Materials Lands are a special category of Labrador Inuit Lands and are also identified in the Labrador Inuit Land Claims Agreement, governed by the Nunatsiavut Government, as land which cannot be quarried without a Specified Material Permit. The Inuit have the exclusive right to ownership of quarry materials and 25 % ownership interest in subsurface resources.

*Within **Labrador Inuit Lands**, Inuit will own:*

- surface title
- all Carving Stone (serpentinite and soapstone)
- all Specified Materials on 3,950 square kilometres of Labrador Inuit Lands referred to as Specified Materials Lands. Specified Materials are quarry materials and are defined as "stone including stone suitable for dimension stone use, labradorite, chert, sand, gravel, clay, topsoil soil, marl, peat and peat moss when these substances are used for construction or agricultural purposes only".
- a 25% ownership interest in all other subsurface resources (minerals, quarry materials, oil and gas) which entitles the Inuit to a 25% share of provincial subsurface revenues as well as a number of rights specified in the Agreement.

It is important to note that Inuit have surface title and will therefore be the ones to decide if a dam and associated structures can occupy the area.

Site MK S-2 lies within Labrador Inuit Lands (LIL-16) and also within Specific Materials Lands SML-39. The Nunatsiavut Government will be responsible for the determination of progress with respect to surface title for this project.

Site 11 lies within Labrador Inuit Lands (LIL-14) and also within Specific Materials Lands SML-32. The Nunatsiavut Government will be responsible for the determination of progress with respect to surface title for this project.

Site development activities on Labrador Inuit Lands require an access permit and surface lease granted through an Application for Access to Labrador Inuit Lands that must be submitted to the Nunatsiavut Government. Applications for Labrador Inuit Lands would have to be submitted to the Deputy Minister of Lands & Natural Resources requesting access and surface lease or surface title.

10.5 Protected Lands

There does not appear to be any issues with protected lands at any of these sites.

10.6 Regulatory Requirements

There are a variety of permits required for the type of development work proposed. In order for the forested areas and water resources to remain intact, permits will be required from the following departments.

A Commercial Cutting Permit and Burning Permit will be required from the Department of Natural Resources with a fee of $21.00 for the Cutting Permit. An Operating Permit would also be required if chainsaws are being used on forested land during forest fire season. These are free of charge at any district office (personal communication).

From the Department of Environment and Conservation, Water Resources Management Division; an Application for Permit to Alter a Body of Water will be required along with some of its appendices such as Schedule D – Fording, Schedule F – Stream Modification, Schedule G – Small Bridges or Schedule H – Other Works within 15 m of a Body of Water. The fees vary depending on the type of work involved.

Fisheries and Oceans Canada (DFO) may require an Application for Authorization for Works or Undertakings Affecting Fish Habitat as well as a Request for Review under the Fish Habitat Protection Provisions of the Fisheries Act. A development proposal would likely be required for submission to DFO which would include information consistent with requirements in the Proponent's Guide to Information Requirements for Review under the Fish Habitat Protection Provisions of the Fisheries Act that describes the plans for development in or near water.

An application will be required to go to Crown Lands as well for a License to Occupy along with the fee of $100.00.

10.7 Stakeholder Analysis

10.7.1 Stakeholder Identification

Stakeholder identification commenced and is ongoing throughout the preparation of feasibility studies to determine the hydraulic potential of Coastal Labrador. The initial listing of stakeholders includes:

- Nunatsiavut Government;
- Inuit Community Government of Hopedale;
- Town Council of Charlottetown;
- Inuit Community Government of Makkovik;
- Town Council of Port Hope Simpson;
- Town Council of Mary's Harbour;
- NunatuKavut

- Local Development Associations;
- Department of Environment and Conservation, Province of Newfoundland and Labrador;
- Department of Fisheries and Oceans Canada, Canadian Government;
- Environment Canada, Canadian Government.

10.8 Aboriginal Groups

The Nunatsiavut Government will be engaged by Hatch Ltd. and NL Hydro in the next month since two of the four sites selected are within Labrador Inuit Lands. The closest communities are those of Makkovik and Hopedale. Although these sites are outside the boundaries of the Inuit Community Governments, these communities will have an interest in the development of land within their region.

NunatuKavut have filed a Land Claim which overlaps areas of southern Labrador, including the Alexis and St. Lewis rivers. While this claim has yet to be accepted for negotiation by Aboriginal Affairs of Northern Development Canada (AANDC), it has been demonstrated that the Province has a duty to consult Labrador Metis with respect to developments.

10.9 Regulatory Agencies

The Province of Newfoundland and Labrador's Crown Lands Division is responsible for the lands wherein Site 8 and Site ALX are located. Charlottetown, Mary's Harbour and Port Hope Simpson are the closest communities to Sites 8 and ALX. The sites lie well outside of the Municipal Planning Areas of these communities, however, Port Hope Simpson and Mary's Harbour are located downstream of these sites and will have an interest in any development that takes place.

The Department of Fisheries and Oceans Canada will have jurisdiction over fish and fish habitat. Environment Canada and the Department of Environment and Conservation's Water Resources Management will be responsible for water quality and water use issues. Migratory birds will also be under Environment Canada jurisdiction.

10.10 Public

Local residents of Makkovik and Hopedale will need to be involved in the consultation process for any development on Makkovik Brook and Adlatok River, respectively. Similarly, residents of Mary's Harbour, Port Hope Simpson, Charlottetown will need to be involved in consultations for developments on both the Alexis River and the St. Lewis River. To this end, groups and organizations such as Town Councils, Regional Economic Development Boards, Fishers' Committees and the general public are important stakeholders that should be engaged in the consultation process.

10.11 Issue Analysis

10.11.1 Potential Issues

There are several potential issues that should be taken into consideration when preparing to engage stakeholders in the consultation process. Such issues are detailed below and include: local resistance to past hydroelectric developments, negative perceptions of the effects of hydroelectric developments, and views on cost and implications of hydro-generated power versus diesel power should be considered. Additionally, consultation processes may serve as forums in which to bring awareness to unresolved land claims.

- Recently, Inuit interveners demonstrated some resistance during the Environmental Assessment process for the Lower Churchill Project, another hydroelectric development in Labrador. This experience illustrates the importance of adequate consultation to engage stakeholder groups and should be taken into account when conducting future consultations on potential projects.
- An emphasis on environmental protection is commonplace among stakeholders and the general local perception of hydroelectric developments should be taken into consideration. Hydro developments can often be perceived as causing flooding and loss of hunting grounds and destruction of fishing resources.
- The cost and availability of hydroelectric power will likely be an important point of discussion among the public. Furthermore, potential displacement of reliance on diesel power generation will likely need to be discussed.
- An Aboriginal group such as the NunatuKavut might be inclined to use a hydroelectric development project as a vehicle by which to raise awareness of their unresolved land claims.

10.11.2 General Considerations

All of the four sites appear to be viable options for small hydro projects. There appears to be no serious identified impacts for mitigation or management for the proposed shortlisted sites. As previously mentioned, Site MK S-2 lies within Labrador Inuit Lands LIL-16 and also within Specific Materials Lands SML-39. Site 11 lies within Labrador Inuit Land LIL-14 and also within specific Materials Lands SML-32. The Nunatsiavut Government will therefore be responsible for the determination of progress with this project.

Site 8 lies along the St. Lewis River and Site ALX lies along the Alexis River, both of which are Class III Scheduled Salmon Rivers. Atlantic salmon and trout parr are reported to be plentiful in the lower areas of the St. Lewis River while large quantities of smelt occur in St. Lewis Inlet and Atlantic salmon and sea-run and resident brook trout are all reported to be present in the Alexis River. Because these are Scheduled Salmon Rivers, Fisheries and Oceans Canada (DFO) will need to be involved in various aspects of this project as they have jurisdiction on fish and fish habitat.

The remaining two sites (MK S-2 and Site 11) are not on Scheduled Salmon Rivers but report runs of Atlantic salmon, as well as other fish species, and are open to angling. The alteration to fish habitat could be an important issue for local residents.

All of the areas will require various permits from the Nunatsiavut Government, Department of Natural Resources, Government of Newfoundland and Labrador Environment and Conservation, and Department of Fisheries and Oceans Canada. A Commercial Cutting Permit will be required and possibly a Burning Permit and Operating Permit from the Department of Natural Resources. An Application for Permit to Alter a Body of Water will be required from the Department of Environment and Conservation, Water Resources Management Division, along with some of its appendices such as Schedule D – Fording, Schedule F – Stream Modification, Schedule G – Small Bridges or Schedule H – Other Works within 15 m of a Body of Water. Department of Fisheries and Oceans Canada will likely require an Application for the Authorization for Works or Undertakings Affecting Fish Habitat, a Request for Review under the Fish Habitat Protection Provisions of the Fisheries Act and a development proposal. An Application for Crown Lands, a License to Occupy and/or Lease will be required from Department of Environment and Conservation, Crown Lands Division.

10.12 Engagement Process and Timelines

10.12.1 Early Meetings with High Level Aboriginal Leadership

Presently, a meeting with the Nunatsiavut Government is being arranged involving Hatch Ltd. and NL Hydro and facilitated by Sikumiut. This meeting will begin the briefing process to bring members of the Nunatsiavut Government up to speed on the status of the feasibility study and potential for hydroelectric development at selected sites.

This meeting is intended to discuss the placement of stream gauges to commence measurement of hydroelectric potential of the selected sites. Though it is not part of the consultation process, input gathered from the Nunatsiavut Government officials during this meeting could be useful in informing future communication efforts.

It is extremely important to set an early precedent during consultation of direct communication from NL Hydro to the Nunatsiavut Government regarding all potential developments on Labrador Inuit Lands or Labrador Inuit Settlement Areas, as well as NunatuKavut regarding developments in southern Labrador. It is highly recommended that project information first reach high level Aboriginal leadership through presentation by NL Hydro.

10.12.2 Revision of Stakeholders Analysis and Issue Analysis

Feedback gained from early consultation with high level Aboriginal leadership can be incorporated into Stakeholder and Issues Analyses to ensure that consultation plans are comprehensive and address all major issues.

10.12.3 Consultation of Other Stakeholders Identified

Once Aboriginal leadership has been engaged, consultation with other stakeholders can begin, as per the Consultation Plan in Appendix H.

10.13 Potential Impact Benefits Agreement Requirements

Sites on Labrador Inuit Lands may become subject to Impact Benefits Agreement (IBA) requirements. IBA negotiations identify means to mitigate and reduce negative effects and augment positive effects of developments. Common subjects include environmental protection and business, employment and training opportunities.

Negotiations can take approximately one year to conclude and must be based on detailed project parameters, not simply on concepts. Therefore it is important that:

1. the project plan (its effects and benefits) is well defined, and
2. the IBA results are stated before the Environmental Assessment concludes.

11. Economic Analysis

11.1 Approach

The scope of the preliminary economic analysis herein undertakes an economic comparison of the potential small-hydroelectric plants indentified as being the four most attractive sites for developing renewable power sources that may serve five Coastal Labrador communities including their supporting infrastructure. This section is limited to a review of three broad categories of criteria used in the economic comparisons of alternative power plants. These are: (i) criteria based on present worth values, (ii) criteria based on the internal rate of return and (iii) criteria based on benefit/cost ratios. The most comprehensive of all present worth criteria involves ranking alternatives according to their net revenues, i.e., according to the difference between the present value of revenues (benefits) and the present value of costs. This criterion is often used in public sector policy analysis. In the case of alternatives of the same project the net present worth or net present value (NPV) is a key indicator of economic feasibility; the most favourable alternative is the one that yields the maximum NPV. The internal rate of return (IRR), of an investment with revenue and cost streams Rt and Ct, respectively, is defined as the rate of discount at which the net present worth of the operation becomes zero. If the proposed hydro investments are examined according to their IRRs, this avoids the use of an externally established discount rate. The benefit/cost (B/C) ratios of the hydro sites are also calculated as part of this analysis whereby the B/C ratio is a measure of the discounted benefits per dollar of discounted costs. It is defined as the ratio of the present worth values of revenues to the present worth values of costs.

In the economic analysis the individual hydro sites are assumed to be characterized by time streams of revenues (or benefits) and costs, where Rt and Ct denote the revenues (benefits) and costs in year t, respectively. Both are measured in monetary terms. A project life of 50 years and a discrete rate of discount (i) are assumed in the mathematical expressions used in the discounting analysis. The discounting is undertaken over annual intervals. The reference point for discounting is the beginning of the first year of the cost disbursement (i.e., the first year of construction of the hydro site). Revenue streams (i.e., generation benefits from the hydro sites) are also discounted to the same reference year.

11.2 Capital Costs

Capital cost estimates of the hydroelectric site works for Site 11, Site MK S-2, Site 8C and Site ALX are discussed in Section 8 and a summary of estimated costs for the individual sites is in Table 8-2 in Section 8. The excluded costs are also described in this section of the report. The details of the project costs are in Figures 8-1 to 8-4 in Appendix F. All costs are in October 2012 Canadian dollars.

The cash flow for the construction of the hydro-sites will occur over 2 years or 3 years depending on the estimated site construction schedule for the respective site. The annual expenditures of capital costs have also been estimated and are provided in Figures 8-5 to 8-8, Appendix F. A summary of the annual percentage of capital costs to be disbursed over

the construction period are given in Table 11-1. Financing costs (interest during construction) during the hydro sites' construction period have not been included in the estimated costs.

Table 11-1: Estimated Project Costs and Cash Flow for Hydro Projects

			Annual Percentage of Estimated Project Costs			
Site	**Estimated Project Cost (Million)**	**Estimated Construction Period (Yrs)**	**Year 1**	**Year 2**	**Year 3**	**Total**
Site 11	$37.9	2.5	43.0%	49.0%	8.0%	100.0%
Site MK S-2	$19.3	2	43.5%	56.5%	-	100.0%
Site 8C	$61.8	3	30.0%	50.0%	20.0%	100.0%
Site ALX	$51.3	2.5	35.0%	55.0%	10.0%	100.0%

11.3 Energy Benefits

The objective of assessing the energy benefits was to determine the revenue stream associated with the proposed hydro development at each site. The revenue stream (represented on an annual basis) is the product of the expected plant generation and the energy price. Energy benefits during the first year of plant operation were assumed to be 50% of the full annual energy benefits to account for generation plant commissioning and other start-up problems. All energy benefits commence in the year following construction completion.

11.3.1 Basis for Selecting Energy Benefits

Currently, electricity to the communities of the four sites is provided by diesel plants. The cost of energy (December 2012 prices) from the diesel plants at Hopedale, Makkovik, Charlottetown, Port Hope Simpson and Mary's Harbour based on fuel displacement only, were provided by NL Hydro. The cost/kWh of diesel generation varies between $0.331 and $0.38 and does not include operation and maintenance cost and other life cycle costs (e.g., replacement of plant). The diesel displacement costs for the five communities are summarized in Table 11-2. The displacement diesel energy prices adopted for hydro generated energy at the respective sites were: Site 11 (Hopedale) - $0.38/kWh; Site MK S-2 (Makkovik) - $0.331/kWh; and CHT/PHS/MSH – a mean value of $0.354/kWh. It is expected that if all displacement costs associated with diesel generation were included then the price of energy from the diesel plants would be higher than the energy cost values in Table 11-2.

Table 11-2: Price of Diesel Generated Energy Based on Fuel Displacement

Community	Site	Average Annual Fuel Conversion Efficiency *a/* (kWh/Litre)	Fuel Cost (2012 CAD/Litre)	Gross Energy Cost ($/kWh)	Net Energy Cost ($/kWh)
Hopedale	11	3.23	1.124	0.348	0.380
Makkovik	MK S-2	3.35	1.075	0.321	0.331
Charlottetown	8C or ALX	3.32	1.082	0.326	0.340
Port Hope Simpson	8C or ALX	3.33	1.099	0.330	0.370
Mary's Harbour	8C or ALX	3.27	1.076	0.329	0.352

a/ Provided by NL Hydro.

11.4 Life Cycle Costs

The only recurrent cost that was included in the economic evaluation of the four hydro sites was the plant and ancillary facilities operation and maintenance (O&M) cost. There are no operating small hydro plants in Coastal Labrador communities so it was not possible to estimate this cost in relation to actual operations. In commercial operations the O&M cost varies between 10% (good plants) and 15% (problematic plants) of annual revenue. Operation and Maintenance costs of the proposed Phase 2 hydroelectric plants and other works for the four sites were assumed to amount to 0.40% of the site development capital cost and would be incurred annually. This estimate of O&M costs is based on data from Canadian plants in other provinces but may have to be reviewed for Coastal Labrador conditions due to the remoteness of the sites.

11.5 Economic Parameters

The main inputs and assumptions in the economic modeling are a discount rate and an annual inflation rate. The discount rate adopted was 7% based on NL Hydro's estimate on the current opportunity cost of capital for this type of investment. The annual inflation rate adopted is 1.5%. Both costs and energy benefits were inflated annually. This would have no impact on the ranking of the projects. Project analysis periods of 25-yr and 50-yr (2013 to 2063) were assumed for the economic analyses.

11.6 Economic Evaluation Results from Analysis

The economic analyses of the each of the four sites were carried out for two cases of energy benefits. In the first case the benefit stream was derived using the average annual energy (the same average annually energy amount is repeated in each year of generation). In the second case, in order to evaluate the potential variability in the hydrology and its effect on the benefit stream, the economic evaluations were carried out using energy benefits simulated by using the actual hydrologic record developed for the individual sites. Since the simulated hydrological series only extended over 33 years then the first 17 years of the series was repeated at the end of year 33 to make up 50 years of annual energies. This shows that quite a wide range of benefits would be possible depending on whether a very dry or a very wet year occurs.

Generated energy from the proposed hydro schemes at Site 11 and Site 8C satisfied more than 100% of the load demand in the early years but no adjustments were made to these energy amounts. The excess energy at Site 8C is small and only occurred during one month in the spring. This was not felt to significantly affect the economic parameters calculated. In the case of Site 11, the impact would be more significant.

Compensation flows were calculated for each site and their deductions were also applied in estimating the energy from each plant for the "with compensation flow" condition. Since no firm decision has been made regarding the appropriateness of these flows at this point in time, these energy streams were not used in the economic evaluation. All benefit streams in the economic analyses are therefore representative of prospective plant energy benefits "without compensation flow".

A summary of the economic results are summarized in Table 11-3.

Table 11-3: Key Economic Parameters from Analysis of Four Preferred Sites

					25 Year			50 Year		
Site	**Installed Capacity (MW)**	**Cost/ kW ($)**	**Energy Benefits Derived From**	**Capacity Factor**	**NPV ($M)**	**IRR (%)**	**B/C**	**NPV ($M)**	**IRR (%)**	**B/C**
Site 11	1.5	$ 25,300.00	Avg. Ann. Energy	93.2%	4.63	8.32	1.13	14.08	9.75	1.39
Site 11	1.5	$ 25,300.00	Actual Hyd. Series	92.7%	4.36	8.26	1.12	14.16	9.74	1.39
Site MK S-2	1.0	$ 19,300.00	Avg. Ann. Energy	44.5%	(6.11)	2.77	0.67	(3.61)	5.36	0.81
Site MK S-2	1.0	$ 19,300.00	Actual Hyd. Series	44.5%	(5.85)	0.71	0.68	(3.33)	5.46	0.82
Site 8C	4.4	$ 14,060.00	Avg. Ann. Energy	74.0%	30.28	12.05	1.53	51.09	12.96	1.88
Site 8C	4.4	$ 14,060.00	Actual Hyd. Series	73.7%	30.48	12.16	1.53	51.82	13.07	1.89
Site ALX	4.4	$ 11,600.00	Avg. Ann. Energy	46.8%	7.46	8.60	1.16	20.46	9.99	1.42
Site ALX	4.4	$ 11,600.00	Actual Hyd. Series	46.7%	8.48	8.84	1.18	21.56	10.18	1.44

The results in Table 11-3 demonstrate that Sites 11, Site 8C and Site ALX have positive NPVs for both the 25-year project period and the 50-year project period. The highest NPV is for Site 8C with a NPV of $30.48 million over 25 years and $51.82 million over 50 years. Hence, Site 8C is the most economically viable site. The second most attractive site is ALX which has a NPV of $8.48 million over 25 years and $21.56 million over 50 years. The IRRs for Site 8C and Site ALX are 12.16% and 8.84% respectively over 25 years and 13.07% and 10.18% over 50 years. The B/C ratios for Sites 11, 8C and ALX are all greater than 1.0. Site 8C has the highest B/C ratio of 1.89. The above economic parameters are for energy benefits based on the actual hydrological series at the respective sites. Since Site 8C and ALX are competing hydro sites to service the combined communities CHT/PHS/MSH then the first choice should be Site 8C. With a capacity factor (CF) of 74% compared to CF = 47% at ALX, it would generate a much larger amount of energy annually.

Site MK S-2 had negative NPVs for both the 25-year period 50-year analysis periods indicating that this site is the least favorable and would not be a financially feasible project. The IRR for MK S-2 is 0.71% at 25 years and 5.46% at 50 years. The B/C ratios are 0.68 and 0.82 for the two analysis periods. MK S-2 has the lowest plant CF at 44.5% with no energy being generated in the months of February and March and extremely small amounts in November, December, January and April.

11.7 Levelized Unit Energy Cost (LUEC)

Levelized costs of unit energy were calculated in the economic analysis using the discount rate of 7% and an amortization period of 50 years. An iterative process was applied to the unit energy cost ($/kWh) to determine the value that gave a net present value of zero. This value was taken as the LUEC for the particular run-of-river hydro site. The LUEC varied between $0.187/kWh at Site 8C to $0.404/kWh at Site MK S-2.

12. Conclusions and Recommendations

12.1 Conclusions

1. On the basis of the completed Phase 1 Study, four sites were selected for feasibility study at Phase 2. On the basis of all additional information collected, updated mapping, more detailed engineering design, revised cost estimates and more detailed energy estimates carried out in Phase 2, the four sites would still be technically feasible but there is a large disparity in their economic viability.

2. Original Site 8 was moved 260 m downstream to a new location called Site 8C. A total of three alternative locations of the Site 8 headworks were examined during Phase 2. The alternative with the least civil works cost was Site 8C but its net head was reduced from 26.1 m to 17 m due to the potential impacts on the upstream tourist lodge, and to reduce the cost of the dam. Its design flow increased from 22.5 m^3/s to 29.7 m^3/s and its proposed installed capacity reduced from 5 MW to 4.4 MW. The new installed capacity proposed at Site 8C closely matches the 2037 load demand for the three combined communities of Charlottetown, Port Hope Simpson and Mary's Harbour (CHT/PHS/MSH). The changes brought about by the Phase 2 feasibility study will mitigate the site's impact on the falls/rapids adjacent to the tourist lodge. Site 8C headpond is smaller than the Phase 1 scheme hence its footprint will significantly reduce headpond environmental impacts. The increase in design flow to compensate for the proposed head reduction resulted in a unit development cost ($/kW) increase of approximately 12%. However, the total estimated project cost was lowered from the Phase 1 total estimated project cost.

3. Site ALX design has been revised under the Phase 2 feasibility study with the spillway being lengthened and the powerhouse moved to the left bank of the river because of the existing access roads being close to that bank of the river. The proposed installed capacity was reduced to 4.4 MW, from 5.0 MW. The increase in unit development cost ($/kW) with the revised design is about 9%, although the total project cost was lowered by 4.2%, from the Phase 1 estimated cost.

4. Site MK S-2 redesigns have resulted in approximately a 40% increase in its unit development cost ($/kW) due partially to the longer penstock now required. Based on the economic evaluation of the four sites, Site MK S-2 is not economically viable since it has a negative net present value (NPV) over both 25 years and 50 years. Its internal rate of return (IRR) is below the adopted discount rate of 7%. Hatch has concluded that no design changes would enhance its economic viability.

5. The Site 11 estimated total project cost under Phase 2 reduced by 3% from the Phase 1 estimated cost but the proposed installed capacity was reduced to 1.5 MW from 2.0 MW. Because of this, its unit development cost increased by 20% to $25,300/kW. Site 11 NPV at 25 years is $4.36 million and $14.2 million at 50 years. The IRRs are 8.3% at 25 years and 9.7% at 50 years and its benefit/cost (B/C) ratio is 1.12 and 1.39 for the two analysis periods. Because of its large river discharges and low installed capacity,

generated energy from Site 11 would meet the project and 2037 energy demand at Hopedale in all months of the year. The Site 11 capacity factor was estimated to be 93%. Because it is on a large river; the required headworks are substantial and costly in order to handle its Inflow Design Flood and diversion floods during construction.

6. An evaluation of the energy utilization on a monthly basis showed that Site 11 and Site 8C had the best performance in meeting the 2037 monthly energy demand. Site 11 met demand in all months which is not surprising given its high capacity factor. Site 8C would meet 88% of annual demand, while Site ALX would meet 56% of its forecasted annual energy demand. Site MK S-2 would meet 50% of its annual energy demand.

7. On the basis of the levelized unit energy cost (LUEC) estimated for the four sites, Site 8C has the lowest LUEC at $0.187/kWh while the value at Site ALX is $0.245/kWh. The LUEC for Site 11 is $0.273/kWh. These values are all well below the existing fuel displacement cost of diesel generation. However, Site MK S-2 has a LUEC of $0.404/kWh and this is above the base diesel generation cost and therefore not competitive with this type of generation.

8. The results of the economic analysis demonstrate that Sites 11, Site 8C and Site ALX have positive NPVs for both the 25-year project period and the 50-year project period. The highest NPV is for Site 8C with a NPV of $30.5 million over 25 years and $51.8 million over 50 years. Hence, Site 8C is the most economically viable site. The second most attractive site is ALX which has a NPV of $4.5 million over 25 years and $21.6 million over 50 years. The IRRs for Site 8C and Site ALX are 12.2% and 8.8% respectively, over 25 years and 13% and 10% over 50 years. The B/C ratios for Sites 11, 8C and ALX are all greater than 1.0. Site 8C has the highest B/C ratio of 1.88. The above economic parameters are for energy benefits based on the actual hydrological series at the respective sites. Since Site 8C and ALX are competing hydro sites to service the combined communities of CHT/PHS/MSH then the first choice should be Site 8C. With a capacity factor (CF) of 74% compared to a CF of 47% at ALX, Site 8C would generate a much larger amount of energy annually.

9. The study of potential storage (Annex) indicates that three hydroelectric storage developments at Site 5B on the Gilbert River, Site 8D on the St. Lewis River and Site ALX-B on the Alexis River are technically viable and are able to produce firm power for the southern communities of CHT, PHS, MSH and STL. The key conclusions on storage potential are contained in the Annex. Generation Option #2 demonstrated that the generation of firm power from Site 5B-2 can be combined with the run-of-river Site 8C-2 to deliver power and energy to satisfy the forecasted load demand from all four communities. This is also the most economical generation option that delivers 2,300 kW of firm power from 5B-2 along with variable power from Site 8C-2. The installed capacities at the two sites would be 2,500 kW at 5B-2 and 3,000 kW at 8C-2. The total cost of this option would be approximately $89 million and the levelized cost of demand

energy is the lowest of all storage generation scenarios analyzed, at $0.240/kWh of demand energy and $0.199/kWh on the supply energy side. If Site 8C-2 is not a potential run-of-river hydro site on the St. Lewis River then the next most favorable generation scenario for firm power is Site 5B-1 at an installed capacity of 2,100 kW and Site ALX-B with an installed capacity of 3,500 kW.

12.2 Recommendations

1. It is recommended that Site 8C should proceed to the next level (environmental assessment/design/implementation) with emphasis on the environmental screening to better define upstream impacts. Should the impacts be substantial and cannot be mitigated then Site 8C may be dropped. The next most economically viable site is ALX and it is recommended that this should also proceed to the next stage, since there is a possibility that the tourist lodge owner could oppose construction of Site 8C.

2. Alternative unit types and a potential revised layout for Site 11 could be investigated, and its economical viability should be evaluated.

3. Site MK S-2 at Makkovik should be compared to alternative energy sources.

4. The installation of the hydrometric collection (gauge) station planned for Site 11 could be cancelled. Site 11 has no hydrological constraints because of the large available flows and the small installed capacity required. Locating this gauge on another river should be considered. The shelter and equipment supplied/purchased for Site MK S-2 should be installed on the Gilbert River in the vicinity of the proposed powerhouse at Site 5B.

References

Ref 1 – Wardle, R. J. 1993. Geology of the Naskaupi River Region, Central Labrador (13 NW), scale 1:500 000, Newfoundland Department of Mines and Energy, Geological Survey Branch, Map 93-16.

Ref 2 – Bailey, D. G. et al 1982. Geology of Kaipokok Bay-Big River Area, Newfoundland Department of Mines and Energy, Geological Survey Branch Map 82-7.

Ref 3 – Gower, C. F., 2010. Geology of the Port Hope Simpson Area (NTS sheets O3D/12 and 13; 13A/09, 10, 15 and 16) southeastern Labrador. Geological Survey, Mines Branch, Department of Natural Resources, government of Newfoundland and Labrador, Map 2010-20, Open File Lab 1565.

Ref 4 – Gower, C. F., 2010. Geology of the St. Lewis River area (NTS sheets O3D/04 and 05; 13A/01, 02, 07 and 08) southeastern Labrador. Geological Survey, Mines Branch, Department of Natural Resources, government of Newfoundland and Labrador, Map 2010-24, Open File Lab 1566.

Ref 5 – Anderson, T.C. 1985. The Rivers of Labrador. Department of Fisheries and Oceans. Canadian Special Publication of Fisheries and Aquatic Sciences; 389 pp.

Ref 6 – Fisheries and Oceans Canada. 2012. Anglers Guide 2012-2013. http://www.nfl.dfo-mpo.gc.ca/e0005647.

Ref 7 – Newfoundland Labrador Hydro. 2009. Preliminary Assessment of Alternative Energy Potential in Coastal Labrador.

Ref 8 – Anderson, T.C. 1985. The Rivers of Labrador. Department of Fisheries and Oceans. Canadian Special Publication of Fisheries and Aquatic Sciences; 389 pp.

Ref 9 – Atlantic Rivers Outfitting Company. 2012. http://atlanticrivers.ca.

Ref 10 – Fisheries and Oceans Canada. 2012. Anglers Guide 2012-2013. http://www.nfl.dfo-mpo.gc.ca/e0005647.

Ref 11 – Hodder, R., (NL Hydro), 2012. 50 Year Forecast – Labrador Coast.

Ref 12 – Moulton, R., (NL Hydro), 2012. Email providing the cost of energy produced at diesel plants for December 2012.

Appendix A

Request for Proposals

REQUIREMENTS FOR

PROFESSIONAL SERVICES

TO BE PROVIDED

REQUEST FOR PROPOSALS

Feasibility Study of Hydraulic Potential of Coastal Labrador

REGISTERED PROFESSIONAL ENGINEER PEGNL Newfoundland and Labrador Carissa M. Sparkes SIGNATURE NOV 4/11 DATE NEWFOUNDLAND & LABRADOR	Electrical
	Mechanical
	Civil
	Protection & Control
	Transmission & Distribution
	Telecontrol
	System Planning Chris Warren

Approved for Release

NOV 4 / 2011
Date

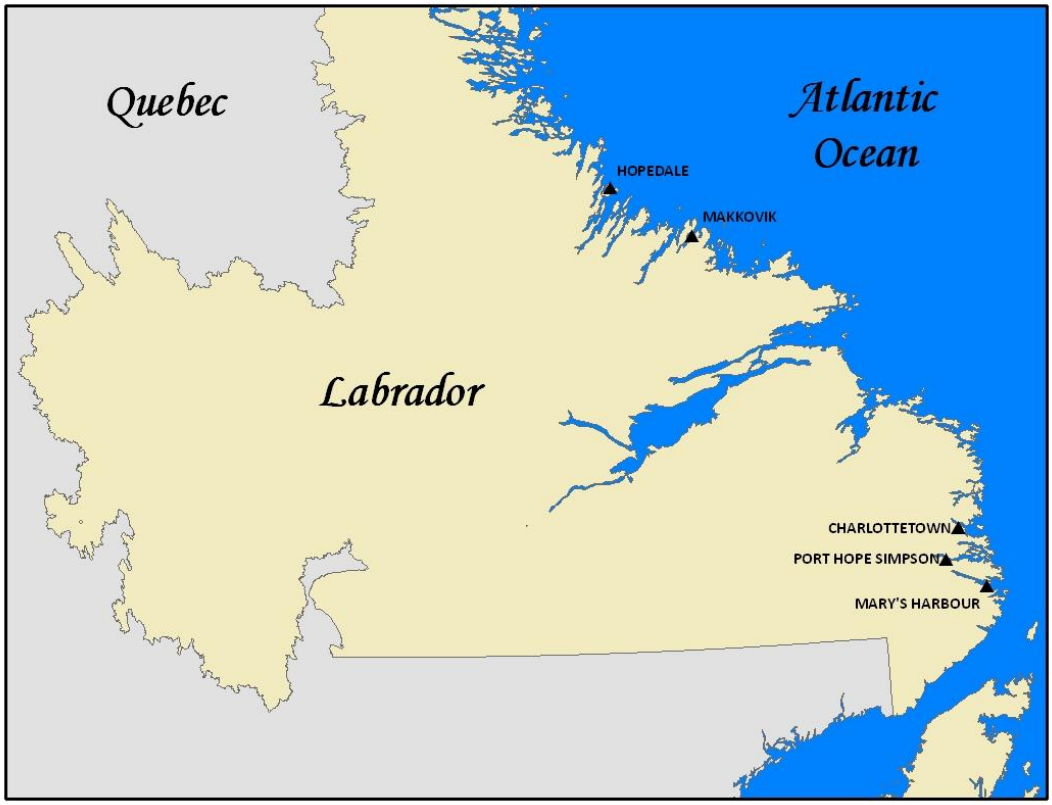
Background

As a follow-up to the Review of Hydraulic Potential of Coastal Labrador, Hatch, 2009 and the Preliminary Assessment of Alternative Energy Potential in Coastal Labrador commissioned by the Government of Newfoundland and Labrador in 2008, Newfoundland and Labrador Hydro is proposing to undertake a feasibility study of the hydraulic potential of sites in the region. The motivation behind this proposal is rooted in the high energy costs in the isolated communities, driven by dependence on non-renewable diesel fuel that must be shipped into the region, and the corresponding environmental impacts of burning those fuels. The proposed project would encompass a three-year streamflow data collection program near the five listed communities and a hydraulic potential study in these areas where initial investigation indicated hydraulic potential could be more competitively priced than diesel fuel.

Project Description

The *Preliminary Assessment of Alternative Energy Potential in Coastal Labrador* identified the communities of Hopedale, Makkovik, Charlottetown, Port Hope Simpson and Mary's Harbour as warranting further investigation into potential for hydraulic development to either supplement or replace the existing diesel plants serving the noted communities. As shown in the map below, the sites are located along the coast of Labrador.

Map of Proposed Sites



There are a number of sites associated with each community. A list of sites with co-ordinates is located in the table below.

Site Number	Nearest Town	Coordinates						Drainage Area (km^2)
		Latitude (N)			Longitude (W)			
		deg	min	sec	deg	min	sec	
5	Charlottetown	52	39	59	56	7	39	600
CH S-3	Charlottetown	52	48	10	56	11	42	89
12	Hopedale	55	26	47	60	27	40	126
1	Makkovik	55	0	39	59	9	35	70
MK S-1	Makkovik	55	3	26	59	9	21	99
MK S-2	Makkovik	55	1	16	59	9	24	74
2	Mary's Harbour	52	7	2	55	52	8	91
4	Mary's Harbour	52	18	3	55	52	5	458
MH S-2A	Mary's Harbour	52	17	29	55	55	5	447
MH S-4	Mary's Harbour	52	12	41	55	58	2	251
PHS S-1	Port Hope Simpson	52	31	39	56	19	55	104
PHS S-3	Port Hope Simpson	52	30	53	56	10	43	51
PHS S-5	Port Hope Simpson	52	33	10	56	27	40	223
9	Port Hope Simpson	52	25	50	56	21	25	2365
3	Port Hope Simpson	52	33	31	56	26	31	229

The proposal should be submitted with mandatory cost breakdown for each site. The cost estimate per site will be broken down into stream monitoring and hydraulic assessment components. Where there are multiple sites within a basin, these sites may be combined with respect to the three year stream monitoring program only. Mapping information is limited. Topographic maps, either via use of GPS ground survey or LIDAR, will be required for each basin as part of this hydraulic assessment project.

Site Access

Due to the remote location of each of the proposed sites, accessibility will be limited. The following information presents known methods of transportation to each of the sites and may be subject to change. It will be the responsibility of the applicant to plan and coordinate travel to the proposed project sites.

Hopedale

- Commercial Cargo Boat – CAI Nunatsiavut Marine
- Provincial Marine Ferry
- Commercial Airline (Air Labrador / Provincial Air)

Charlottetown

- Provincial Marine Ferry
- Commercial Airline (Air Labrador)
- Provincial Highway Route 510 and Route 514
- Labrador Straits Ferry

Port Hope Simpson

- Provincial Marine Ferry
- Commercial Airline (Air Labrador)

- Provincial Highway Route 510
- Labrador Straits Ferry

Makkovik

- Commercial Cargo Boat - CAI Nunatsiavut Marine
- Provincial Marine Ferry
- Commercial Airline (Labrador Air / Provincial Air)

Mary's Harbour

- Commercial Airline (Labrador Air)
- Provincial Highway Route 510
- Labrador Straits Ferry

Please note that due to the remote location of these areas each of these modes of transportation are limited to specific operational schedules. The successful applicant shall be responsible for providing a safe and effective method of transportation to each of the sites. Helicopter services for travel to and from the proposed locations may also be available.

Project Scope and Objectives

Subject to **HYDRO's** direction and review, the **SERVICES** which **CONSULTANT** shall perform or cause to be performed with diligence, skill and care for the completion of the **PROJECT** will include the following, but may not be limited to:

- Reviewing all previous work performed by others and related to this **PROJECT**;
- Visit each noted site for data collection as well as set up of flow data collection at proposed sites.
- Collect contour data and develop topographic maps with 1m contour intervals for each site. The consultant shall to determine how this objective shall be met and present to **HYDRO** in the proposal.
- Review and verify hydrology at each specified site to confirm the appropriateness of each site for micro (up to 100kW), mini (100kW to 1000kW) and small (1MW o 15 MW) hydroelectric generation facilities
- Review load table outcomes, calculate potential power and energy output to determine effective options for hydroelectric potential.
- Consider combinations of stand alone run of river projects, interconnected run of river projects and reservoir projects to determine the best solution for each community and make recommendations based on the least cost solution. Project optimization is required to determine the least cost solutions, which may include maintaining existing diesel plants at a reduced capacity or full displacement of diesel plants.
- Evaluate and comment on the transmission requirements, constructability and other desirable qualities of each hydroelectric development site.
- Collect geotechnical information required to substantiate recommended locations and provide report of geotechnical findings.

- Collect, validate and archive three years of stream flow data from each basin or site, whichever the consultant deems appropriate for data collection. Report on the flow data collection once per year over the three year collection program. Remove flow data collection infrastructure at **HYDRO's** discretion.
- Provide cost estimates for each hydroelectric development option under study. Include a comprehensive comparison of all components required to deliver the specified load to each community.
- Provide a list of environmental impacts and mitigations for each site as well any specific land claim issues that may be affected by the development or access to the development of each site.
- Provide an overall ranking of potential sites based on total per-unit energy costs and environmental risk.
- Provide 20% complete site layouts for each site option reviewed, showing major project features and potential areas of concern at the sites.
- Acquisition of all required permits on behalf of **HYDRO**.

Schedule and Deliverables

The hydroelectric assessment services herein shall be completed by November 1, 2012. The stream flow data collection services herein shall be completed by June 2015. To meet these dates and to facilitate the early selection of a Consultant, the following schedule and deliverable dates apply:

Receipt of Proposal.....November 30, 2011

Acceptance of a proposal by **HYDRO** .....December 14, 2011

Confirmation of Stream flow program details ..... January 11, 2012

Preliminary hydroelectric options to **HYDRO**..... June 30, 2012

Initial draft report …… ....August 9, 2012

Presentation of draft Feasibility Report (for **HYDRO's** review & comments) .....August 30, 2012

HYDRO's response to draft Feasibility Report ..... October 4, 2012

Submission of Feasibility Report to **HYDRO** .....November 1, 2012

Annual stream flow data report to **HYDRO** ..... June 28, 2013

Annual stream flow data report to **HYDRO** ..... June 27, 2014

Annual stream flow data and **FINAL** flow data report to **HYDRO** ..... June 26, 2015

Information Provided

All reports and information listed below shall be provided to the **CONSULTANT** in pdf format.

All reports and information provided to **PROPONENT/CONSULTANT** by **HYDRO** remain the sole property of **HYDRO** and shall not be used for any purpose without the written consent of **HYDRO**

Before submitting its proposal, **CONSULTANT** shall become familiarized with any pertinent information and reports that may be available to it, including but not limited to the following:

- Preliminary Assessment of Alternative Energy Potential in Coastal Labrador, Report Prepared by the System Planning Group, Nalcor Energy for the Department of Natural Resources December, 2009.

- Review of Hydraulic Potential of Coastal Labrador, Report prepared by Hatch, November 2009.

Remuneration for the Service

CONSULTANT shall provide its proposed pricing to complete the **SERVICES**, which shall include the following minimum detail:

- Person-hours and associated cost for each job classification, including mark-ups for Employee Benefits, Overheads and profit. If applicable, include for field office(s)

- Reimbursable (out-of-pocket) costs by classification and location;

- Anticipated sub-consulting services by location; and

- Monthly cost flows for the proposed budget.

PROPONENT'S PROPOSAL

.1 **PROPONENT's PROPOSAL** shall, as a minimum, include the following information:

(a) a listing of the **PROPONENT's** experience pertinent to the nature of the **SERVICES**, including applicable project descriptions, dates and clients' names and addresses;

(b) details of the organizational structure and personnel proposed for performance of the **SERVICES** and such personnel shall not be changed by the **CONSULTANT** over the duration of the **SERVICES** without the prior written consent of **HYDRO**;

(c) curriculum vitae for all proposed management and professional personnel;

(d) an outline of the methodology intended for performance of the **SERVICES**; including as a minimum: key activities, involvement of proposed personnel, planned field investigative work and method of performance, person hours and cost (budget);

(e) two (2) schedules, in bar-chart format, one each for both key work activities and person-hours by classification;

(f) basis of remuneration, in the level of detail indicated elsewhere herein;

(g) acknowledgement that the accuracy of the cost estimate included in the **FEASIBILITY REPORT** shall be within an accuracy range of plus or minus 10%.

.2 All costs associated with **PROPOSAL** preparation, including but not limited to matters such as **PROPOSAL** development, investigations, site visits, clarification and other meetings shall be the responsibility of and borne solely by the **PROPONENT**, and shall not be subject to any reimbursement by **HYDRO**.

SUBMISSION OF PROPOSALS

.1 One (1) original and two (2) copies of the **PROPOSAL** shall be submitted to **HYDRO** before 3:00 p.m., local time on November 28, 2011 at the following address:

Supply Chain Management Department
Newfoundland and Labrador Hydro
500 Columbus Drive
P.O. Box 12400
St. John's, Newfoundland and Labrador
A1B 4K7

ATTENTION: MANAGER OF SUPPLY CHAIN MANAGEMENT
RFP for FEASIBILITY STUDY OF HYDRAULIC POTENTIAL OF COASTAL LABRADOR

.2 During the **PROPOSAL** preparation period **PROPONENT** may seek written clarification on **PROPOSAL** requirements by contacting Ashley Billiard, not less than seven (7) days prior to the date for **PROPOSAL** submission stipulated in clause 6.1

.3 **HYDRO** shall not be responsible for oral instructions or clarifications and no instructions or clarifications shall be binding unless communicated by **HYDRO** in writing.

VALIDITY PERIOD

Each **PROPOSAL** shall remain open for acceptance and irrevocable for a period of ninety (90) days after the deadline for receipt of Proposals.

VENDOR Verification

PURCHASER uses Browz for vendor document compliance review and management**.**

VENDORS who are registered and deemed compliant through Browz are **not** required to submit the following information as requested in this tender document.

- Certificate of Insurance
- Documents outlined in clause 1.16 Contractor Safety Management Program
- Proof of completion of the Environmental Awareness Program from the Newfoundland and Labrador Construction Safety Association
- Certificate of good standing with the Workplace, Health, Safety and Compensation Commission

Browz members are required to provide their Browz ID number.
If you are not a member of Browz, all documentation outlined in this tender document must be submitted with your Form of Tender at the time of Bid Submission, or your tender response will be considered non compliant.

Insurance

.1 **CONSULTANT** shall provide, at its cost, insurances with limits not less than stated in this Article. Upon award, as evidence of insurance, Insurer shall be required to provide a completed Certificate of Insurance, on Owner's form, a sample of which is appended.

.2 **CONSULTANT** shall provide Commercial General Liability (CGL) Insurance (including Environmental Impairment Liability) which shall have a limit of not less than $1 million for any one occurrence to cover property damage or loss, bodily injury and loss of life. **PURCHASER** has no liability and no coverage under its insurance for **CONSULTANT**'s equipment used in carrying out **WORK**.

.3 **CONSULTANT** shall provide Automobile Liability Insurance with a limit of not less than $1 million combined for any one occurrence including personal injury, loss of life or property damage or loss.

.4 **CONSULTANT** shall carry professional errors and omissions liability insurance in an amount not less than one million ($1,000,000) dollars and shall ensure that each consultant who has a professional liability exposure and who is engaged by the **CONSULTANT** in the performance of the **WORK** is covered against professional errors and omissions in an amount not less than one million ($1,000,000) dollars. Such insurance shall be in effect for at least twelve (12) months following FINAL ACCEPTANCE or completion of the **WORK**, whichever is longer.

.5 **PURCHASER** shall be an additional insured on all certificates of insurance, with a cross-liability clause.

.6 All insurance shall be maintained in full force during the performance of **WORK.**

.7 All insurance policies shall contain an article to provide that the insurance shall not be cancelled or materially changed in any way without thirty (30) days notice, except in the event of non-payment when policy conditions dealing with termination will apply. Such notice shall be sent by registered mail to:

Newfoundland and Labrador Hydro
P.O. Box 12400
St. John's, Newfoundland and Labrador
A1B 4K7

Attention: Manager of Risk and Insurance

.8 Deductibles applicable to required insurance shall not exceed $5,000 for any one occurrence. **CONSULTANT** shall be responsible for deductible amounts under policies and for providing such additional insurance as required to protect the insured's against loss on items excluded from policies.

.9 Additional insurances and minimum limits per accident or occurrence required for **WORK** to be performed under this Specification are:

- Forest Fire Fighting Expense (included under CGL) sublimit $ 250,000.00.
- Environmental Impairment Liability - $1,000,000.00.

Depending on the proposal, all of these additional insurances may not be required. It will be at Hydro's sole discretion to eliminate the requirement for the additional insurances as listed above once the proposals are received. If so determined that the project work scope requires the above mentioned insurance, the **CONSULTANT** is required to provide insurance documentation prior to the start of any field and construction work.

Purchasing Terms

HYDRO Group's Purchasing Terms and Conditions – Professional Services shall apply. Attached Appendix I

Contractor Safety Management Program

The **CONSULTANT/CONTRACTOR** responsible for performing the work is required to comply with **HYDRO's** Contractor Safety Management Program. In the event that the construction portion of the work is sub-contracted, the sub-contractor must also comply with the Contractor Safety Management Program.

TENDERER upon notification, must submit within 3 business days, the completed **Worksheet C - Contractor Safety Qualification Questionnaire.**

PURCHASER endorses the Certificate of Recognition from the Newfoundland and Labrador Construction Safety Association (NLCSA). **TENDERER** upon notification, must submit within 3 business days, proof of a valid Certificate of Recognition form the NLCSA or proof of a valid certificate from a similar accreditation / safety program acceptable to **PURCHASER**.

Failure to comply with the above may result in disqualification of submitted tender.

Upon notification, preferred **TENDERER** will be required to submit a copy of its company Safety Management Program within 10 business days to the **PURCHASER** or will result in disqualification of tender.

CONTRACTOR shall designate a qualified safety site coordinator for the duration of the contract. The same person may act as the technical supervisor as well as the safety site coordinator.

CONTRACTOR is advised that **PURCHASER'S** Safety Hazards Evaluation has resulted in the identification of a number of hazards related to the **WORK**. A copy of **Worksheet B – Contract Safety Hazards Evaluation Form is provided** for information of the **CONTRACTOR.**

CONTRACTOR shall prepare and submit a Risk Assessment prior to commencing the **WORK** to identify any possible hazards which may pose a risk to safety of persons and property. The **Worksheet D – Contractor Risk Assessment Form** shall be used to record the risk assessment control methods to be employed by the **CONTRACTOR**. The completed Risk Assessment shall be submitted to **PURCHASER** for review and approval prior to commencement of **WORK**. All actions required to eliminate or mitigate the safety risks identified shall be carried out prior to start of **WORK.**

CONTRACTOR shall provide a list of all personnel expected to perform work under the contract as well as evidence of training records, qualifications and licenses required for that work. The **CONTRACTOR** shall complete a **Worksheet E - Contractor Personnel & Qualifications Form.** This form is to be submitted prior to commencement of the **WORK**.

CONTRACTOR shall hold tailboard safety talks with its crew prior to commencement of work on site each day and whenever changes in the scope of work occur. Minutes of these meetings shall be documented and provided to **PURCHASER**'s site safety coordinator.

CONTRACTOR shall supply to **PURCHASER** a Safety and Health Plan specific to the contract and **WORK**. The Safety and Health Plan shall consider and respond to the specific safety and health site hazards, emergency preparedness, issues relevant to the **WORK** and shall document the systems and methods to be implemented for the term of the contract. **PURCHASER** shall review the Safety and Health Plan and formal approval to commence the **WORK** shall be provided subject to acceptance of the Safety and Health Plan. The Risk Assessment Form may be included in the document.

If during the performance of **WORK**, **PURCHASER** informs the **CONTRACTOR** that it is not conducting the **WORK** in compliance with the Safety and Health requirements of the contract, then the **CONTRACTOR** shall remedy that discrepancy promptly. **PURCHASER** may direct the **CONTRACTOR** to suspend **WORK** until such time as the **CONTRACTOR** satisfies **PURCHASER** that the **WORK** will be resumed in conformance with applicable safety and health provisions. If the **CONTRACTOR** fails to rectify any breach of safety and health for which the **WORK** has been suspended, or if the **CONTRACTOR**'s performance has involved recurring non-conformance with safety and health requirements, **PURCHASER** may at its option terminate the **WORK** without further obligation to the **CONTRACTOR**.

Prior to receiving payment each month, **CONTRACTOR** shall be required to submit **Worksheet L – Contractor Safety Statistics – Monthly Report**.

Worksheet G - Contract Closeout and Evaluation Form must be signed off by the **CONTRACTOR** as a requirement for the Release of the Holdback monies.

CONTRACTOR and its subcontractors are to utilize **PURCHASER'**s Safe Workplace Observation Program ('SWOP") in the reporting of unsafe work conditions or hazards that may be presented on site. **CONTRACTOR** shall be presented with SWOP Cards and encouraged to participate in the program. **CONTRACTOR'S** SWOP reports will be presented to the on-site supervisor in the form of a commendation, condition, near miss or loss incident.

Evaluation of Proposals

The following criteria, as well as those criteria listed under **PROPONENT PROPOSAL** Section of this document will be used to evaluate the submitted proposals. Due to the nature of the proposed **WORK**, the successful bidder will be selected on the basis of the highest ranking obtained and will not be solely based on the final bid price.

Table 1 – Evaluation criteria

ITEM	KEY CONSIDERATIONS	MAXIMUM POINTS
1	**UNDERSTANDING OF SCOPE OF WORK**	
1.1	Recognition of Scope and Objectives	5
1.2	Compliance with RFP	5
1.3	Methodology	30
1.4	Innovation	5
	Sub-Total	/45
2	**CONSULTANT'S CAPABILITY AND EXPERIENCE**	
2.1	Experience in Similar Work	10
2.2	Project Team (Organization and Experience)	15
2.3	Location of Office(s)	5
2.4	Familiarity with Project Environment	5
	Sub-Total	/35
3	**PROPOSED ALLOCATION OF PERSON-HOURS AND EXPENDITURES**	/10
4	**COST OF SERVICE**	/5
5	**QUALITY OF PRESENTATION**	/5
	TOTAL POINTS	/100

Evaluation of Proposals

The evaluation of proposals will be based on, but not limited to, the following considerations:

(a) all relevant legal and financial considerations;

(b) capability of Respondent, based on the relevant experience of the Respondent and the personnel to be assigned to the Services;

(c) technical adequacy of the proposal including appreciation of the scope of the Services and proposed methodology to undertake the study; and

(d) basis of remuneration and the proposed cost estimate for performance of the Services.

Progress Meetings

.1 The **CONSULTANT** shall be expected to convene a regular monthly progress review meeting which will be attended by **HYDRO** personnel and shall generally address the following and any other subjects that may be pertinent to the performance of the **SERVICES**: Typically, the monthly meeting can be done via conference call; all relevant information shall be sent to **HYDRO** prior to the meeting and shall be followed up by minutes of the meeting taken by the **CONTRACTOR**.

(a) a review of the status of the technical aspects of the **SERVICES**, including design and site layout options, details of any data collection and data summary studies undertaken and the status of any field programs;

(b) the schedule and cost budget for the **SERVICES** versus the actual person-hours and cost expended by activity to the date of the meeting;

(c) the time and cost to complete the **SERVICES** and the total forecast-final-cost of performance of the **SERVICES**; and

.2 The **CONSULTANT** shall prepare and circulate in a timely manner the minutes of such meetings and shall have them acknowledged by the **CONSULTANT**'s project Manager and **HYDRO**. The minutes of previous meetings shall be reviewed at subsequent meetings until all action requirements are completed.

Report or Submissions

CONSULTANT must supply copies of their proposal as per Feasibility Section below. An electronic PDF copy of the draft and final reports shall also be submitted to **HYDRO** within two weeks of said report submission.

Feasibility Report

.1 Upon completion of the study the **CONSULTANT** shall provide **HYDRO** with eight (8) copies of the draft Feasibility Report for its review and comments. The submission shall be complemented by a presentation in which the key aspects of the study, the conclusions reached and recommendations made can be discussed. In any event, **HYDRO**'s comments on the draft Feasibility Report will be conveyed to the **CONSULTANT** within one (1) month of its receipt by **HYDRO**.

Following review of the draft Feasibility Report with **HYDRO**, as provided for herein, the **CONSULTANT** shall finalize its Feasibility Report and present **HYDRO** with twelve (12) copies. As a minimum, the draft and final Feasibility Reports shall address all activities undertaken by the **CONSULTANT** in the performance of the Services, including the following:

(a) background information and studies used;

(b) the scope and results of field investigative work, analyses undertaken, layouts considered, variables examined, operational considerations, study results, and all other optimization factors;

(c) the assumptions made and market tests performed in the preparation of the cost estimate for **PROJECT** development;

(d) confirmation that the cost estimate, inclusive of contingency amounts, for Project development included in the Feasibility Report is within an accuracy range of not more than plus or minus 10%;

(e) any key considerations pertinent to protection of the Project Cost estimate and construction schedule envisaged in the feasibility Report;

(f) as an appendix:
- details of the cost estimate;

(g) an electronic copy of the report in PDF format and in word document should also be submitted to **HYDRO**.

.2 All design files, calculations including computerised data and design files, original drawings, test results, survey and site investigation information, air photos, and other data produced during performance of the **SERVICES** shall become the property of **HYDRO** on completion of the **SERVICES**.

.3 The contents of the Report shall be kept confidential and shall not be released to third parties without **HYDRO**'s prior written permission.

.4 An electronic copy both the draft and final reports in PDF format shall be submitted to **HYDRO** within 2 weeks of the delivery of the paper copies of said reports.

CLARIFICATION MEETING

If required by **HYDRO** before a **PROPOSAL** is accepted, **PROPONENT** shall, at its cost, attend a Clarification Meeting to review the RFP or its **PROPOSAL**, and such Meeting shall be held at **HYDRO**'s offices.

ENVIRONMENTAL AWARENESS PROGRAM

Where **CONSULTANT** will be managing contracts involving site work, **HYDRO** endorses the Environmental Awareness Program of the Newfoundland and Labrador Construction Safety Association. **CONSULTANT** shall provide proof of completion, by its Supervisors and Managers, of this Environmental Awareness Program or a similar program acceptable to **HYDRO**. Proof shall be provided prior to the commencement of **WORK**.

Appendix I - STANDARD PURCHASING TERMS AND CONDITIONS - PROFESSIONAL SERVICES

Appendix II – CERTIFICATE OF INSURANCE

Appendix III – CONTRACTOR SAFTEY MANAGEMENT FORMS

Worksheet B – Contract Safety Hazards Evaluation Form
Worksheet C - Contractor Safety Qualification Questionnaire
Worksheet D – Contractor Risk Assessment Form
Worksheet E - Contractor Personnel & Qualifications Form
Worksheet G - Contract Closeout and Evaluation Form
Worksheet L – Contractor Safety Statistics – Monthly Repo

Appendix B

Site Visit Report

Safety • Quality • Sustainability • Innovation

Trip Report

October 16, 2012

Newfoundland and Labrador Hydro
Hydraulic Potential of Coastal Labrador
Phase 2: Project Definition Phase

Distribution

Those present
+ Gerard Piercy (NL Hydro)
+ Carissa Sparkes (NL Hydro)
+ George Frank (Hatch)
+ Mike Ragwen (Hatch)

Site Visit Report

Date: September 17-20, 2012

Location: Sites 11, MK S-2, 8 and ALX (plus Sites 4 and 5)

Present: Stefan Cahill (Sikumiut)
David Besaw (Hatch)
John Davies (Hatch)
Murray McFarlane (Hatch)

Purpose: Site reconnaissance and field surveys of preferred sites

1. Introduction

Site visits were made between September 17 to 20 to six potential mini and small hydro sites near Coastal Labrador communities by personnel from Hatch and Sikumiut as noted above. The site visits were part of the Phase 2 work, for the four preferred sites that were selected in the Phase 1 advanced screening plus return visits to Sites 4 and 5. The locations of the sites lie between Hopedale to Mary's Harbour. Goose Bay was used as the base of operation. Transportation to the sites was by an A Star helicopter, provided by Canadian Helicopters.

The purposes of the visits were:

- Additional ground truthing at preferred sites.
- Collect additional hydraulic and geologic data at the hydro sites.
- Verify structure locations, as layouts of sites have been completed by Hatch in its St. John's office prior to the trip.
- Check for other potential sites north of Site 11, and downstream of Site 8.

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- Reconfirm the head at the four preferred sites.
- Meet with the mayor and members of the Charlottetown Town Council regarding the hydro studies.
- Re-examine the existing Mary's Harbour Site 4 mini hydro station; and, Site 5 south of Charlottetown.

1.1 Sites and Site Locations

The sites visited are identified from north to south in Table 1 below. The town nearest each site is indicated.

Table 1: Potential Hydro Sites Visited

Area/Nearest Town	Site Identification No.
Hopedale	11
Makkovic	MK S-2
Charlottetown	5
Port Hope Simpson	8, Alexis
Mary's Harbour	4

The general locations of these sites are shown in Figures 1, 2, 3, 4 and 5.

1.2 Weather

There were no weather delays and the program was completed as planned. It was cloudy and cool for much of the time, with high winds on September 18.

1.3 Safety

Prior to the site trip, a comprehensive safety program was established. Potential hazards were identified in the Project Health and Safety Manual. Each morning the Job Hazard Assessment was reviewed and a Pre-Start Meeting Checklist/Sign-Off Sheet was completed. There were no safety incidents during the site visits.

2. Details of Site Reconnaissance

2.1 General

The work conducted at each site is identified in Table 2. Generally, nine categories of work were performed at sites 8, ALX, MK S-2 and 11.

- Fly over
- Measurement of head
- Geological observations
- Construction material observations
- Flow measurement
- Search for alternate scheme

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Table 2: Work Conducted

Site ID	Fly Over	Landed at Site	Head Measurement	Geological Obs.	Const. Mat. Obs.	Flow Measurement	Search for Alt. Scheme	Photos
11	Y	Y	Y	N	N	N	Y	Y
MK S-2	Y	y	Y	Y	N	N	N	Y
Alexis	Y	Y	Y	Y	Y	N	N	Y
8	Y	Y	Y	Y	N	Y	Y	Y
8 Alt	Y	Y	Y	Y	N	N	Not applicable	Y
9	Y	N	Y	N	N	N	N	Y
4	Y	Y	N	N	N	N	N	Y

Y – Yes
N – No



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- Establish survey control at MK S-2
- Photography
- General observations

These work items are discussed below.

2.2 Itinerary

Table 3 outlines the itinerary of the site visits.

Table 3: Site Visit Itinerary

Date	Sites Visited
September 17	ALX and Site 4
September 18	Site 11 and MK S-2
September 19	Site 8 and Site 8 Alternate
September 20	Site 5 and Town of Charlottetown

2.3 Fly Over

All of the sites were flown over in helicopter to re-assess the site characteristics and in the case of Site 8 Alternate, it was assessed for the first time.

2.4 Landing at Site

Sites ALX, 8, MK S-2 and 4 were examined from the ground. In cases where head measurements were taken without landing, water level elevations were taken from the helicopter.

2.5 Head Measurement

The head was measured at the above four sites using differential GPS by Stefan Cahill of Sikumiut. The head was also measured at Site 5 and at the original Site 9. Elevation measurements were often taken in the helicopter. For this to work, the receiver was located in the forward bubble area of the helicopter. The existing head at the falls at Site ALX was confirmed to be correct as measured in June 2012 (approximately 9.2 m).

2.6 Geological Observations

Further geological observations were completed for ALX, MK S-2, Site 8 and Site 8 Alternate on the ground and from the helicopter. These observations included bedrock exposure, type, weathering and strength, structural geology, ice jacking, river deposits and abutment soil deposits.

2.7 Construction Material Observations

It was re-confirmed that glacio-fluvial sand exists on both sides of the river at the ALX site. The sand on the north side appears to contain gravel on one of the terraces adjacent to the river.

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2.8 Flow Measurements

Flow measurements were completed at Site 8. The river section was profiled and flow velocity was measured using oranges in the river, timed between a measured distance.

There was insufficient flow at MK S-2 for measurement. No flow measurements were taken at Sites ALX (has existing water gauge station) nor 11, as both rivers have known high flows.

2.9 Alternate Site Locations

Alternate site locations were reviewed in the following areas:

- Stretch of coastline North of site 11 toward Hopedale. No potential sites were found.
- A site with approximately 3.5 m of additional head was examined about 700 downstream of Site 8. This site is referred to as Site 8 Alternate.

2.10 Photographs

Photographs were taken using a GPS Sony camera and a non-GPS Cannon camera for all sites. A photo log and photographs form Appendix A of this report.

2.11 Topographic Control

Topographic control was established at the future flow measurement station at MK S-2 from a geodetic benchmark in Makkovic. The control consists of a bolt hammered into a rock fissure. The bolt is flagged with red ribbon.

3. Results of Site Visit

3.1 General

The results are presented in Table 4 under five topics:

- Head measurement
- Flow measurement
- Geological observations
- Construction material observations
- General observations

3.2 Existing Facilities in Hydro Site Drainage Basins

As identified during the Phase 1 Site Visits, there is a tourist/fishing lodge under construction located on the north side of the falls at Site 9 on the St. Lewis River. Site 9 is not considered feasible because of the tourist lodge and because the flow over the falls would be significantly reduced to use for the power flow if a hydro station was constructed at the base of the falls. Initial layout drawings completed in Phase 1 indicated that the maximum gross head for Site 8 is about 27.5 m. The measured elevation difference between Site 8 and the base of the falls was approximately 23.3 m. Site 8 Alternate is approximately 700 m downstream of Site 8 and is approximately 3.5 m lower which would provide a potential maximum gross head of 26.7 m.

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The headpond of Site 11 may impact existing fishing camps upstream of the site. A small group of cabins located on the headwaters of Site 11 were identified during the site visit. Preliminary layout drawings of site 11 indicate that the headwater will be marginally increased. The cabins are set back from the waterline; however, it must be confirmed if raising the reservoir could impact the camps. There is also a fishing camp located at the mouth of the Adlatok River.

There is an existing mini hydro development on the St. Mary's River at Site 4. The single unit plant has a capacity of 135 kW which uses the St. Mary's water intake canal as its headwaters. The hydro electric development has not been in operation since 2007 when the powerhouse was flooded and the unit was damaged. The Phase 1 site visit report (photos) identified a structure as the water intake structure for St. Mary's. It has since been clarified that this structure is actually the powerhouse.

3.3 Charlottetown Meeting

A meeting requested by the Town of Charlottetown with representatives of the Town and Hatch was held on September 20, 2012. Attendees of the meeting included Charmaine Powell (Town Mayor), Stewart Mcnab (Town Clerk), Brad Pye (Town Councillor), John Davies (Hatch), Murray McFarlane (Hatch) and Derek O'Brien (Canadian Helicopters). The meeting took place in the Charlottetown town hall and minutes of the meeting were recorded by Stewart Mcnab.

The intention of the meeting was to provide an overview of the Coastal Labrador energy studies and the Coastal Labrador Hydro Studies in particular to the town officials and to answer any questions. The topics of the meeting were presented to the town council that evening.

3.3.1 Summary of the Meeting

The following was presented by M. McFarlane and discussed informally:

- Summary of energy studies.
- Locations of potential sites.
- Site 8 or site ALX could power the three southern communities.
- Site 5 is a potential site for Charlottetown and potentially could provide enough electricity for Port Hope Simpson as well.
- Main source of demand for Charlottetown is the existing shrimp processing plant (Labrador Choice Seafood) which only operates in the summer.
- Current peak demand for Charlottetown is approximately 2 MW.
- Diesel generators in Charlottetown also supply power to Pinsent's Arm.

Concerns Raised by Mayor and Council

- Electricity rates in Charlottetown are greater than those for Goose Bay. Citizens of Charlottetown are charged for electricity on a bracketed system ranging from approximately 11 to 17 cents per kWh depending on the amount of electricity used.

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- Difficult to attract business with current cost of electricity.
- Prior to Hatch visit, were unclear of timeframe for hydro project.
- Charlottetown will not experience any economic benefit from the Muskrat Falls Project.
- Owner of new fishing camp on the St. Lewis River may be opposed to hydroelectric development at Site 8.

3.3.2 Minutes of Meeting

The Town of Charlottetown's minutes for the September 20, 2012, meeting held at the Charlottetown Town Office are attached in Appendix B of this Site Visit Report.

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Table 4: Results

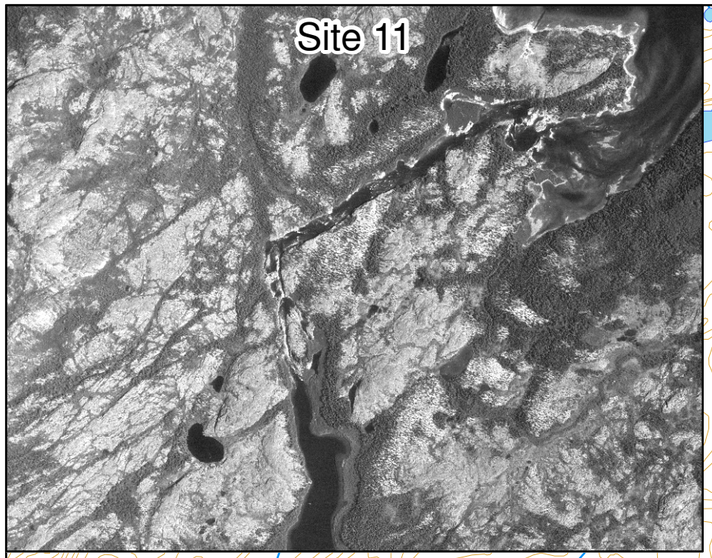
Site ID	Head Measurement (m)	Flow Meas. (m^3 / sec)	Geological Observations	Construction Material Observations	General Observations
11	7.7	Not possible to measure	- None made	- None made	- The coastline was examined for other potential sites between Site 11 and Hopedale. None were found.
MK S-2	92.7 (Head of Site 1 and MK S-2)	Not possible to measure	- Exposed rock at dam location; powerhouse on edge of alluvial delta	- None made	- Fly over only - Hydrometric station to be installed near upper pond, Hatch established bench mark.
Alexis	9.1	Not necessary to measure	- Exposed bedrock in river, left side and upstream edge of peninsula; sand deposit exists for about half of peninsula on right side and right bank	- Extensive sand banks left and right of dam and downstream - Gravel component in sand on left side terrace	- Existing hydrometric station upstream of rapids - Wide river section at falls - powerhouse location is best on left side (for access and transmission)
8	23.3 (to bottom of Site 9 falls)	19.1	- Bedrock on both abutments of dam/PH site with shallow alluvium in riverbed	- Not examined	- Rock outcrops on either side of river provide constriction and a good potential dam site - Logging roads constructed in vicinity of site
8 Alternate	26.7 (to bottom of Site 9 falls)		- Strong but fractured granite bedrock on both abutments of dam/PH site with shallow alluvium in riverbed; shallow overburden on upper slopes	- Not examined	- Rock outcrops on either side of river provide constriction and a good potential dam site
4	Not measured	Not measured	- Existing intake feeds town water supply and non-operating powerhouse. At outflow from existing powerhouse is boulder deposit in stream, no bedrock	- Not examined	- Existing hydropower plant on shoreline of river at Site 4

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Figures

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Hopedale

264

-0.29

-5.821

7.361

Legend

- Survey Points
- Project Gauge
- Aerial Photo Location

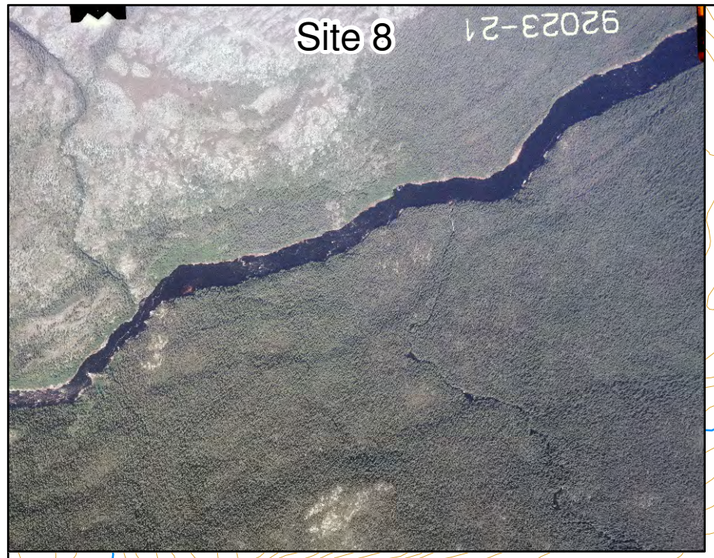
Newfoundland Labrador Hydro

Coastal Labrador Small Hydro Feasibility Study

Figure 1
Hopedale Site 11

0 1,400 2,800

Meters



N

9.57

116

13.793

13.82

17.165

40.478

54.898

Legend

- Hydrometric Gauge
- Survey Points
- Aerial Photo Location

Newfoundland Labrador Hydro

Coastal Labrador Small Hydro Feasibility Study

Figure 2
Port Hope Simpson Site 8

0 1,200 2,400

Meters



N

9.094

14.46

23.446

23.543

32

Port Hope Simpson

Legend

- Towns
- Aerial Photo Location
- Survey Points

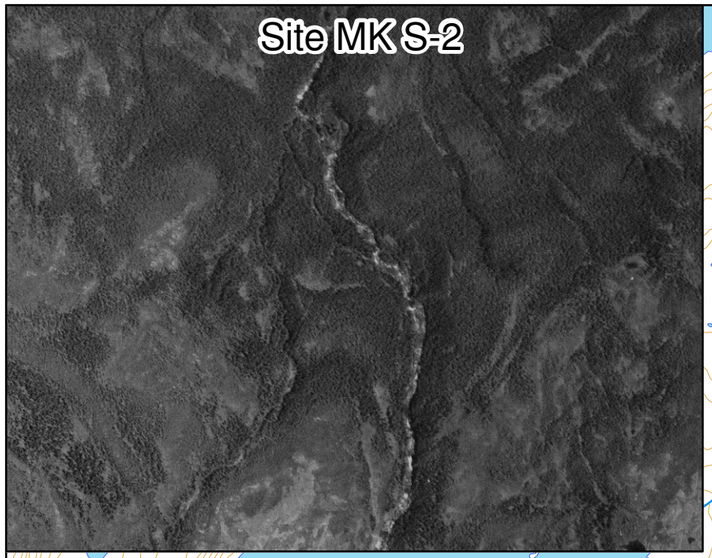
Newfoundland Labrador Hydro

Coastal Labrador Small Hydro Feasibility Study

Figure 3
Port Hope Simpson Site ALX

0 1,300 2,600

Meters



Makkovik

23.059 2.37

24.424

180.025

104.432

114.902

117.136

201.153 199.797

200.943

Legend

- Survey Points
- Towns
- Aerial Photo Location

Newfoundland Labrador Hydro

Coastal Labrador Small Hydro Feasibility Study

Figure 4
Makkovik Site MK S-2

0 2,500 5,000

Meters



N

Mary's Harbour

Legend

- Towns
- Existing Mini Hydro Station
- Aerial Photo Location

Newfoundland Labrador Hydro

Coastal Labrador Small Hydro Feasibility Study

Figure 5
Mary's Harbour Site 4

0 700 1,400
Meters

Appendix A

Photo Logs and Photographs

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Coastal Labrador Hydro
Phase 2: Project Definition Phase
Site Visits - September 17-20, 2012
Site: Site ALX
Location: Alexis River
Nearest Town: Port Hope Simpson

Item	Photo #	No. Photos	Location	Date	Comments
1	4379	1	PHS	9/17/2012	Upstream view of Site ALX
2	4385, 4386	2	PHS	9/17/2012	Aerial view of falls at Site ALX
3	4387	1	PHS	9/17/2012	Aerial view of pool downstream of Site ALX.
4	4388	1	PHS	9/17/2012	Aeral view of left bank of Site ALX.
5	4396	1	PHS	9/17/2012	Ground view looking upstream from hydrometric station upstream of Site ALX.
6	4402	1	PHS	9/17/2012	Site ALX looking upstream from the right bank. Survey indicates approximately a 9m elevation difference between the upstream and downstream pools.
7	4404	1	PHS	9/17/2012	Ground view from left bank, looking upstream. Location of proposed discharge channel of spillway.
8	4405	1	PHS	9/17/2012	Ground view from left bank, looking downstream to lower pool. Location of proposed discharge channel of spillway.
9	4406	1	PHS	9/17/2012	Ground view from the left bank of Site ALX. Note rock ledge which runs between shoreline and island. Location of proposed overflow spillway.
10	4410	1	PHS	9/17/2012	Ground view from the left bank, looking upstream into approach channel. Note shallowness of existing river.
11	4412	1	PHS	9/17/2012	Aerial view of right channel around Island. Note shallow sandy bottom. Location of approach channel for powerhouse for current Site ALX layout.
12	4413, 4414	2	PHS	9/17/2012	Upstream view of Right bank of Site ALX. Proposed location of diversion.
13	4416	1	PHS	9/17/2012	Aerial view of right channel around island at falls. Location of overflow spillway and cofferdam.



Photo 4379



Photo 4385



Photo 4386



Photo 4387

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Photo 4388



Photo 4396



Photo 4402



Photo 4404

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Photo 4405



Photo 4406



Photo 4410



Photo 4412

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Photo 4413



Photo 4414



Photo 4416

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Coastal Labrador Hydro
Phase 2: Project Definition Phase
Site Visits - September 17-20, 2012
Site: Site 11
Location: Adlatok River
Newest Town: Hopedale

Item	Photo #	No. Photos	Location	Date	Comments
1	4445	1	Hopedale	9/18/2012	Headwaters of Adlatok River at Site 11
2	4446	1	Hopedale	9/18/2012	Fishing camp on headwaters of Site 11. Raising pond may inundate buildings.
3	4449	1	Hopedale	9/18/2012	Upstream view of approach to falls at Site 11.
4	4450	1	Hopedale	9/18/2012	Downstream view of Site 11. Powerhouse is on the right side of the island. Overflow spillway is on the channel to the left of the island.
5	4452	1	Hopedale	9/18/2012	Adlatok River from headwaters of Site 11 to Mouth in Adlatok Bay.
6	4464	1	Hopedale	9/18/2012	Upstream view of headwaters of Adlatok River at Site 11.
7	4466		Hopedale	9/18/2012	Downstream view of headwaters of Adlatok River at Site 11.
8	4474, 4480, 4481	3	Hopedale	9/18/2012	Aerial views of Site 11.
9	4483	1	Hopedale	9/18/2012	Approach to chute at Site 11. Overflow spillway located in chute to the left of the island.
10	4488	1	Hopedale	9/18/2012	Downstream view of site 11 with headwaters in background.
11	4489	1	Hopedale	9/18/2012	Mouth of Adlotok River at Adlatok Bay.
12	4493, 4507, 4509, 4514	4	Hopedale	9/18/2012	Potential sites located between Site 11 and Hopedale. Note low flow in rivers.
13	4520, 4522	2	Hopedale	9/18/2012	Typical terrain between Site 11 and Hopedale. Note rocky terrain and several lakes. Location of access road and transmission line.



Photo 4445



Photo 4446



Photo 4449



Photo 4450

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Photo 4452



Photo 4464



Photo 4466



Photo 4474

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Photo 4480



Photo 4481



Photo 4483



Photo 4488

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Photo 4489



Photo 4493



Photo 4507



Photo 4509

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Photo 4514



Photo 4520



Photo 4522

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Coastal Labrador Hydro
Phase 2: Project Definition Phase
Site Visits - September 17-20, 2012
Site: MK S-2
Location: Makkovik Brook
Nearest Town: Makkovik

Item	Photo #	No. Photos	Location	Date	Comments
1	4525	1	Makkovik	9/18/2012	Aerial view of Makkovik
2	4534	1	Makkovik	9/18/2012	Bench mark in Makkovik used for vertical control
3	4540	1	Makkovik	9/18/2012	Headwaters of Makkovik Brook
4	4543	1	Makkovik	9/18/2012	Mouth of Makkovik Brook
5	4544	1	Makkovik	9/18/2012	Upstream view of mouth of Makkovik Brook
6	4554	1	Makkovik	9/18/2012	Location of future hydrometric gauge on Makkovik Brook. Located just downstream of Makkovik Brook headwates.
7	4564	1	Makkovik	9/18/2012	Upstream view of Site MK S-2
8	4567	1	Makkovik	9/18/2012	Dowstream view of natural constriction in river
9	4577	1	Makkovik	9/18/2012	Downstream view of location of Powerhouse.
10	4578	1	Makkovik	9/18/2012	Aerial view looking upstream of site MK S-2



Photo 4525



Photo 4534



Photo 4540



Photo 4543

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Photo 4544



Photo 4554



Photo 4564



Photo 4567

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Photo 4577



Photo 4578

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Coastal Labrador Hydro
Phase 2: Project Definition Phase
Site Visits - September 17-20, 2012
Site: Site 8
Location: St. Lewis River
Nearest Town: Port Hope Simpson

Item	Photo #	No. Photos	Location	Date	Comments
1	4588, 4589	2	PHS	9/18/2012	New fishing lodge located upstream of Site 9
2	4595, 4596, 4597	3	PHS	9/18/2012	St Lewis River upstream of Site 8.
3	4602	1	PHS	9/18/2012	St Lewis River downstream of falls at new Fishing Lodge.
4	4614	1	PHS	9/18/2012	Upstream view of river at gauge location.
5	4616	1	PHS	9/18/2012	Location of future gauge.
6	4624	1	PHS	9/18/2012	Upstream view of Site 8. Note natural rock abutments on either side.
7	4629	1	PHS	9/18/2012	Downstream view of alternative location for development approximately 700m downstream of Site 8 (Site 8 Alt).
8	4632	1	PHS	9/18/2012	Ground view, looking downstream at Site 8 Alt.
9	4634	1	PHS	9/18/2012	Ground view, looking upstream at Stie 8 Alt.
10	4641, 4645, 4650	3	PHS	9/18/2012	Aerial views of Site 8 Alt.
11	4655	1	PHS	9/18/2012	Left bank of St Lewis River at Site 8 Alt. Note rocky outcrops.
12	4661	1	PHS	9/18/2012	Right bank of St Lewis River at Site 8 Alt. Note rocky outcrops.
13	4662, 4666	2	PHS	9/18/2012	Typical terrain between Site 8 and Trans Labrador Highway. Note rocky terrain and high level of vegetation. Location of access road and transmission line.
14	4673	1	PHS	9/18/2012	Trans Labrador Highway approximately 8km North of Site 8.



Photo 4588



Photo 4589



Photo 4595



Photo 4596

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Photo 4597



Photo 4602



Photo 4614

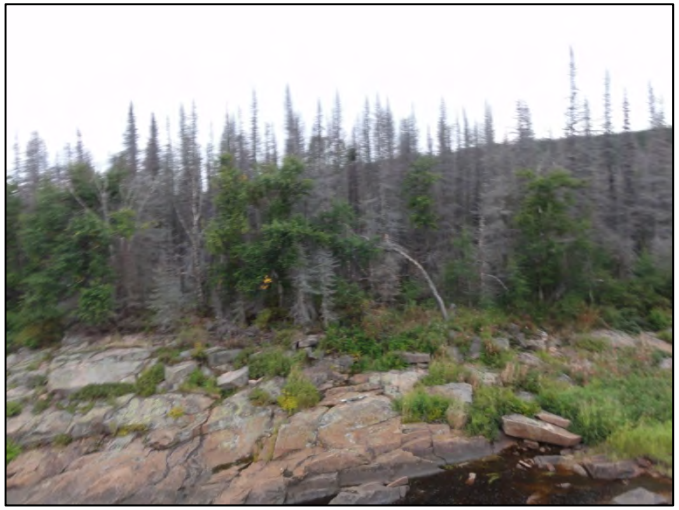


Photo 4616

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Photo 4624



Photo 4629



Photo 4632



Photo 4634

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Photo 4641



Photo 4645



Photo 4650



Photo 4655

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Photo 4661

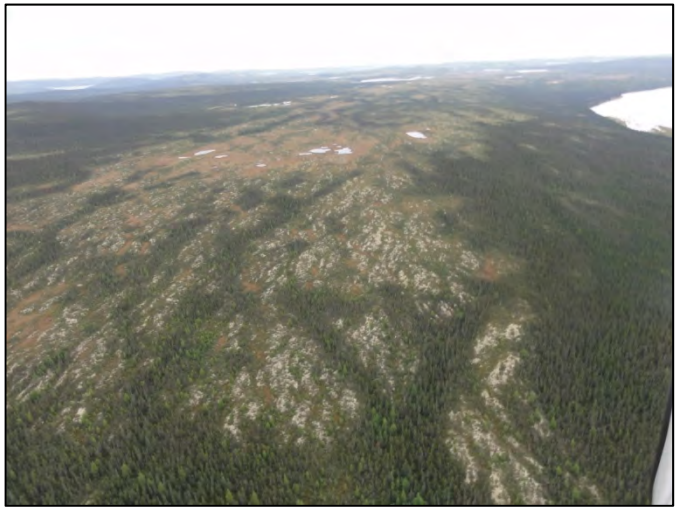


Photo 4662



Photo 4666



Photo 4673

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Coastal Labrador Hydro
Phase 2: Project Definition Phase
Site Visits - September 17-20, 2012
Site: Site 4
Location: St. Mary's River
Nearest Town: Mary's Harbour

Item	Photo #	No. Photos	Location	Date	Comments
1	4424, 4425, 4426, 4427	4	Mary's Harbour	9/17/2012	Aerial views of St Mary's River at Site 4
2	4430	1	Mary's Harbour	9/17/2012	Water intake structure for St Mary's
3	4431	1	Mary's Harbour	9/17/2012	Approach canal for water intake
4	4432, 4433	2	Mary's Harbour	9/17/2012	Existing hydro plant outside of St Mary's
5	4443	1	Mary's Harbour	9/17/2012	Intake to existing hydro plant.
6	4444	1	Mary's Harbour	9/17/2012	Draft tube of existing hydro plant.



Photo 4424



Photo 4425



Photo 4426



Photo 4427

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Photo 4430



Photo 4431



Photo 4432



Photo 4433

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Photo 4443



Photo 4444

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Coastal Labrador Hydro
Phase 2: Project Definition Phase
Site Visits - September 17-20, 2012
Site: Site 5
Location: Gilbert River
Nearest Town: Charlottetown

Item	Photo #	No. Photos	Location	Date	Comments
1	4677	1	Charlottetown	9/17/2012	Upstream view of Gilbert River headwater.
2	4679	1	Charlottetown	9/17/2012	Downstream view of Gilbert River headwater
3	4680	1	Charlottetown	9/17/2012	Shoreline characteristics of Gilbert Lake
4	4681	1	Charlottetown	9/17/2012	Aerial view of Gilbert River.
5	4683	1	Charlottetown	9/17/2012	Aerial view of falls at mouth of Gilbert River into Gilbert Bay.
6	4684	1	Charlottetown	9/17/2012	Aerial downstream view of Gilbert River. Falls is in the foreground with Gilbert Lake in the background.
7	4689, 4690	2	Charlottetown	9/18/2012	Aerial view of town of Charlottetown.



Photo 4677



Photo 4679



Photo 4680



Photo 4681

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Photo 4683



Photo 4684



Photo 4689



Photo 4690

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Appendix B

Minutes of Meeting

Town of Charlottetown

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Town of Charlottetown

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Charlottetown, NL
A0K 5Y0



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Meeting with HYDRO

Held On:	September 20th, 2012	
Held At:	Town Office	
Present:	Mayor:	Charmaine Powell
	Councillors:	Brad Pye
	Hatch:	Derek O'Brien (pilot)
		John Davies (Hatch)
		Murray McFarlane (Hatch)
	Town Clerk:	Stewart Macnab

Meeting called to order at 10:20 am

Introduction

Meeting planned with HYDRO at their request to go over proposed options/plans for alternative power sources for rural Coastal Labrador communities. Members at the meeting representing HYDRO were from the engineering company Hatch (formerly Acres International, the company who designed Churchill Falls in the 1960s). Hatch is presently working on studies for HYDRO for the alternative energy sources of hydro and wind for Coastal Labrador communities.

History

In 1987, a study examining the possibility of developing small/mini hydro plants in rural communities across Labrador was brought to Government. This study led to the construction of a mini hydro plant near Mary's Harbour (about 1989). In 2009, Hatch completed a review of the hydraulic potential of Coastal Labrador, and 36 potential hydro sites were identified in this study.

Town of Charlottetown

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Most power in Coastal Labrador communities is from diesel plants, but with growing costs of diesel fuel, Government has been re-examining the costs of alternative hydro and wind power. Hatch was awarded two contracts in late 2011/early 2012 to examine wind and waterpower sites, which could serve energy needs of the communities of Nain, Hopedale, Makkovik, Cartwright, Charlottetown, Port Hope Simpson, and Mary's Harbour. From the list of 36 potential waterpower sites identified in the 2009 study, this was shortlisted to 15 sites by Hatch in Phase 1 of the 2012 hydro power studies, applicable to the communities of Charlottetown, Port Hope Simpson, Mary's Harbour (CHT/PHS/MSH), and, Hopedale and Makkovik.

Today

Phase 2 of the current hydro study got underway in August, 2012. Hatch has selected and further shortlisted the number of hydro sites to four, 1 for Hopedale, 1 for Makkovik, and 2 alternate sites that could serve the present and future combined energy requirements of CHT/PHS/MSH.

M. McFarlane explained that the following categories exist for small hydro:

- Micro Hydro – 0 to 100 kilowatts (kW)
- Mini Hydro – 100 kW to 1,000 kW
- Small Hydro – 1,000 kW to 10,000 kW

For CHT/PHS/MSH combined, it was determined that a 4.5 or 5 megawatt (MW) small hydro plant would offer enough power to service the area for the next 25 years, based on load forecasts completed by HYDRO. CHT has about double the energy needs of PHS or MSH, mostly because of the successful shrimp plant in CHT. Wind power is not a viable option for CHT/PHS/MSH, but is for Hopedale and Makkovik.

The two selected sites that could serve the combined needs of CHT/PHS/MSH are:

- Site #8 – St. Lewis River, closest community is PHS
- Upstream falls on the Alexis River, closest community is PHS

Hatch is also considering the option of two hydro plants serving the three communities. This could be the combination of Site #5 located on the Gilbert River, only about 7 km from CHT, and a second small hydro plant (say either Site #8 or Alexis) that would serve PHS and MSH.

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When looking at the Alexis River site compared to Site #8, it was determined both would offer sufficient power to serve CHT/PHS/MSH. A potential showstopper at Site #8 is the current development of a very expensive tourist/fishing resort just upstream of Site #8 on the St. Lewis River. Site #5 could potentially offer enough power to serve one community, such as CHT.

The upfront construction cost of Site #8 would be higher than the Alexis River site, because a large dam would be required at Site #8, and only a low overflow dam at Alexis. However, Site #8 would provide the lowest cost of annual energy production of the two, due to the availability of the full power flow over a higher percentage of the time per year. There is an existing water level (water flow) gauge installed adjacent to the Alexis River site, therefore present flow data is more accurate for this site than others. The installation of new water gauges at Site #8 and the Hopedale and Makkovik sites, are part of the current scope of work.

Currently there is no time frame for hydro plant construction because the process is still in early stages. The current Phase 2: Project Definition Phase of the Hydro study will be completed at the end of November, 2012. The wind study involves measurement of the wind regime near certain communities over another 3 years.

HYDRO is taking the initiative to meet with rural communities now to answer potential questions or concerns.

Appendix C

Reference Hydrology

Safety • Quality • Sustainability • Innovation

Appendix C – Reference Hydrology

Development of Long Term Inflow Sequences

C-1) Map of gauge locations
C-2) List of gauges
C-3) Gauge Physiographic Parameters
C-4) Physiographic Parameters of Potential Project Sites
C-5) Prediction Equations for FDC Analysis
C-6) Gauge Flow Duration Curves
C-7) Site 11 Drainage Basin Figure
C-8) Site Flow Duration Curves
C-9) Daily Inflow Sequence Charts
C-10) Mass Plots of Daily Inflow Sequences
C-11) Synthesized Average Monthly Flows

Flood Hydrology

C-12) Selected Gauges for Flood Frequency Analysis
C-13) Gauge Flood Frequency Estimates
C-14) Flood Frequency Prediction Equations
C-15) Comparison of Flood Estimates
C-16) Flood Frequency Plot at Site ALX (WSC Gauge 03QC002)

Hydrometric Data Collection Program

C-17) Hydrometric Gauge Photos

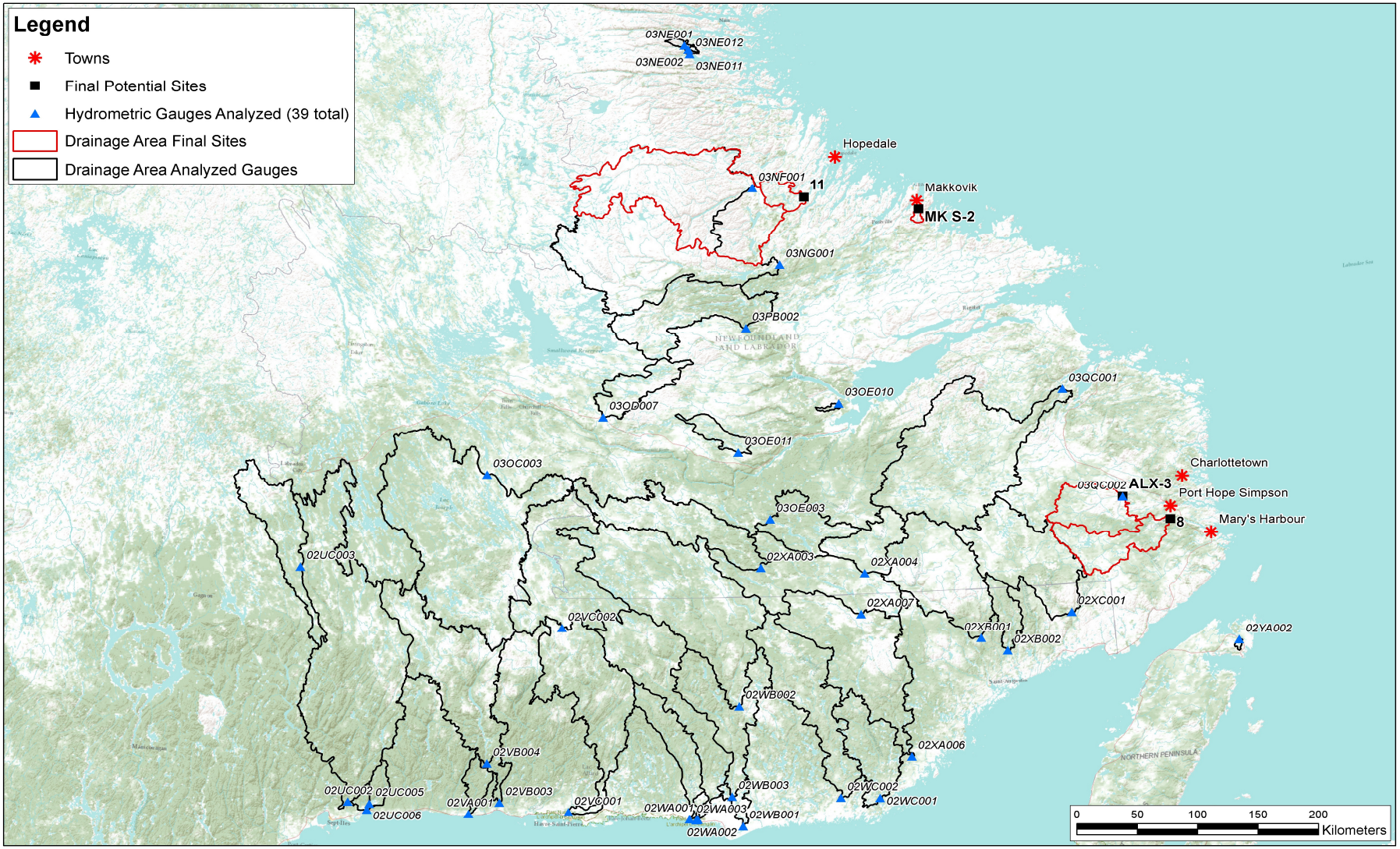


Figure C-1

Hydrometric Gauge Locations

Coastal Labrador Small Hydro Feasibility Study

Newfoundland Labrador Hydro

Gauge Number	Gauge Name	Drainage Area (km^2)	Mean Annual Flow (m^3/s)	Mean Annual Runoff (mm)	Period of Record	Complete Years of Record	Complete Years Used for Analysis
02XA003	LITTLE MECATINA RIVER ABOVE LAC FOURMONT	4478.0	94.1	663	1978 - 2010	30	32
02XA004	RIVIERE JOIR NEAR PROVINCIAL BOUNDARY	2056.6	43.3	663	1980 - 1996	15	17
02YA002	BARTLETTS RIVER NEAR ST. ANTHONY	36.6	1.4	1179	1986 - 2010	25	25
03NE001	REID BROOK AT OUTLET OF REID POND	75.5	2.2	910	1995 - 2010	12	16
03NE002	AMP POND BROOK BELOW CAMP POND	24.9	0.5	694	1995 - 2010	12	16
03NE011	REID BROOK BELOW TRIBUTARY	155.4	3.7	744	2003 - 2010	7	8
03NE012	TRIBUTARY TO REID BROOK	15.2	0.2	491	2003 - 2010	7	8
03NF001	UGJOKTOK RIVER BELOW HARP LAKE	7307.3	161	693	1979 - 2010	31	32
03NG001	KANAIRIKTOK RIVER BELOW SNEGAMOOK LAKE	8926.0	184	651	1979 - 1996	17	18
03OC003	ATIKONAK RIVER ABOVE PANCHIA LAKE	15884.5	310	615	1972 - 2010	15	15
03OD007	EAST METCHIN RIVER	1776.0	21.3	378	1998 - 2010	12	12
03OE003	MINIPI RIVER BELOW MINIPI LAKE	2219.0	57.2	812	1979 - 2010	28	32
03OE010	BIG POND BROOK BELOW BIG POND	70.7	1.7	777	1994 - 2010	16	16
03OE011	PINUS RIVER	800.2	16.2	638	1998 - 2010	12	12
03PB002	NASKAUPI RIVER BELOW NASKAUPI LAKE	4540.9	91.1	633	1978 - 2010	29	33
03QC001	EAGLE RIVER ABOVE FALLS	10705.0	255	750	1966 - 2010	40	42
03QC002	ALEXIS RIVER NEAR PORT HOPE SIMPSON	2312.0	52.0	709	1978 - 2010	33	33
02UC002	MOISIE (RIVIERE) A 5,1 KM EN AMONT DU PONT DU Q.N.	18956.7	419	697	1965-2001	31	35
02UC003	PEKANS (RIVIERE AUX)	3355.7	75.7	711	1965-1982	16	16
02UC005	MATAMEC (RIVIERE)	459.2	12.7	872	1974-1986	9	11
02UC006	MATAMEC (RIVIERE) EN AVAL DE LA RIVIERE AUX RATS M	679.4	20.4	945	1975-1986	4	10
02VA001	TONNERRE (RIVIERE AU)	682.5	20.5	947	1947-1986	32	32
02VB003	MAGPIE (RIVIERE)	7530.7	182	762	1965-1979	13	13
02VB004	MAGPIE (RIVIERE) A LA SORTIE DU LAC MAGPIE	7139.6	166	733	1978-2001	22	22
02VC001	ROMAINE (RIVIERE) AU PONT DE LA Q.I.T.	12940.7	297	724	1956-2001	43	43
02VC002	ROMAINE (RIVIERE) EN AVAL DE LA RIVIERE AUX SAUTER	6568.0	151	725	1972-1982	10	10
02WA001	NABISIPI (RIVIERE)	2055.6	65.0	997	1962-1988	25	25
02WA002	AGUANUS (RIVIERE) EN AMONT DE LA RIVIERE DANY	5597.6	162	913	1962-1982	19	19
02WA003	DANY (RIVIERE) PRES DE LA RIVIERE AGUANUS	149.8	4.18	880	1962-1972	8	8
02WB001	NATASHQUAN (RIVIERE) PRES DE L'EMBOUCHURE	15828.8	419	835	1962-1971	9	9
02WB002	NATASHQUAN (RIVIERE) EN AVAL DE LA RIVIERE NATASHQ	11406.7	297	821	1966-1983	16	16
02WB003	SHQUAN (RIVIERE) A 0,6 KM EN AVAL DE LA DECHARGE D	15383.3	342	701	1980-2001	19	19
02WC001	ETAMAMIOU (RIVIERE) PRES DE L'EMBOUCHURE	2939.8	100	1073	1974-1993	18	18
02WC002	OLOMAN (RIVIERE) EN AVAL DE LA RIVIERE WABOUCHAGAM	5230.0	156	941	1980-1988	7	7
02XA006	PETIT MECATINA (RIVIERE DU)	19267.2	505	827	1965-1980	11	14
02XA007	PETIT MECATINA (RIVIERE DU) EN AVAL DU LAC BRETON	12108.6	297	774	1978-1993	11	16
02XB001	SAINT-AUGUSTIN (RIVIERE) EN AVAL DE LA RIVIERE A L	5725.3	178	982	1967-1982	14	14
02XB002	COXIPI (RIVIERE) A LA SORTIE DU LAC COXIPI	1024.8	26.9	827	1980-1993	10	11
02XC001	SAINT-PAUL (RIVIERE) A 0,5 KM DU RUISSEAU CHANION	5524.2	148	854	1967-2001	28	33

Validation Gauges

Gauge Number	Gauge Name	Drainage Area (km^2)	Mean Annual Flow (m^3/s)	Mean Annual Runoff (mm)	Period of Record	Complete Years of Record
03NE005	BROOK AT OUTLET OF POND 56	16.4	0.766	1470	1996-1998	2
02XD001	BRADOR (RIVIERE) PRES DE L'EMBOUCHURE	205.3	9.55	1470	1969-1988	7
02VA003	TONNERRE (RIVIERE AU) EN AMONT DU PONT-ROUTE 138	673.1	17.5	820	1984-1993	5

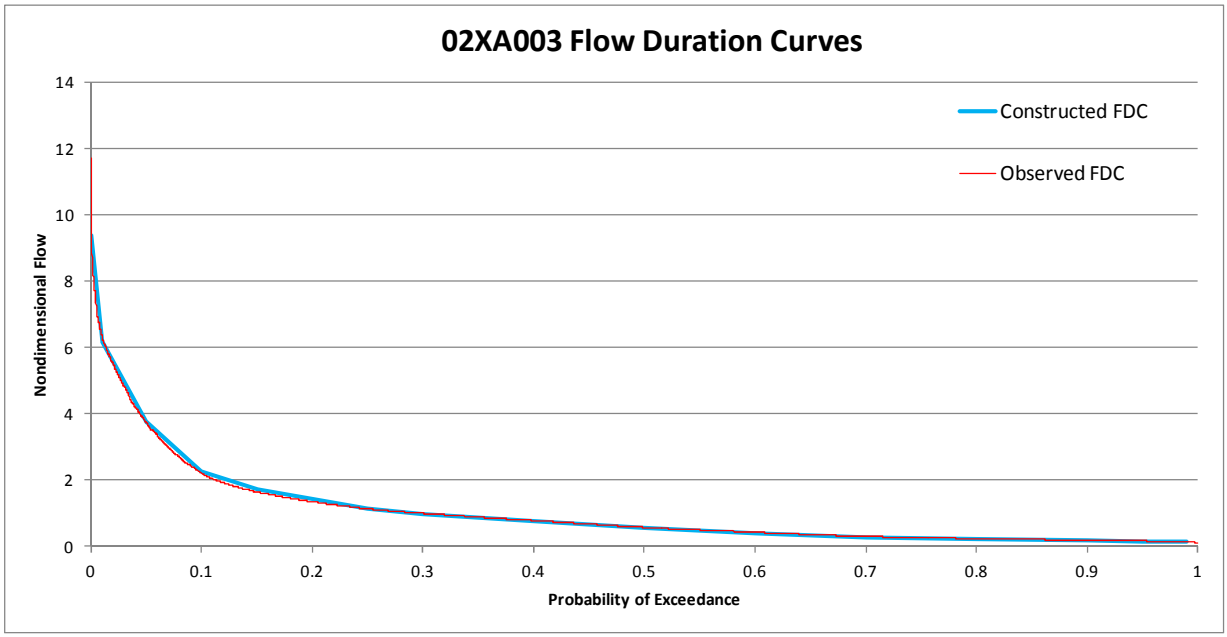
Table C-3
Gauge Physiographic Parameters

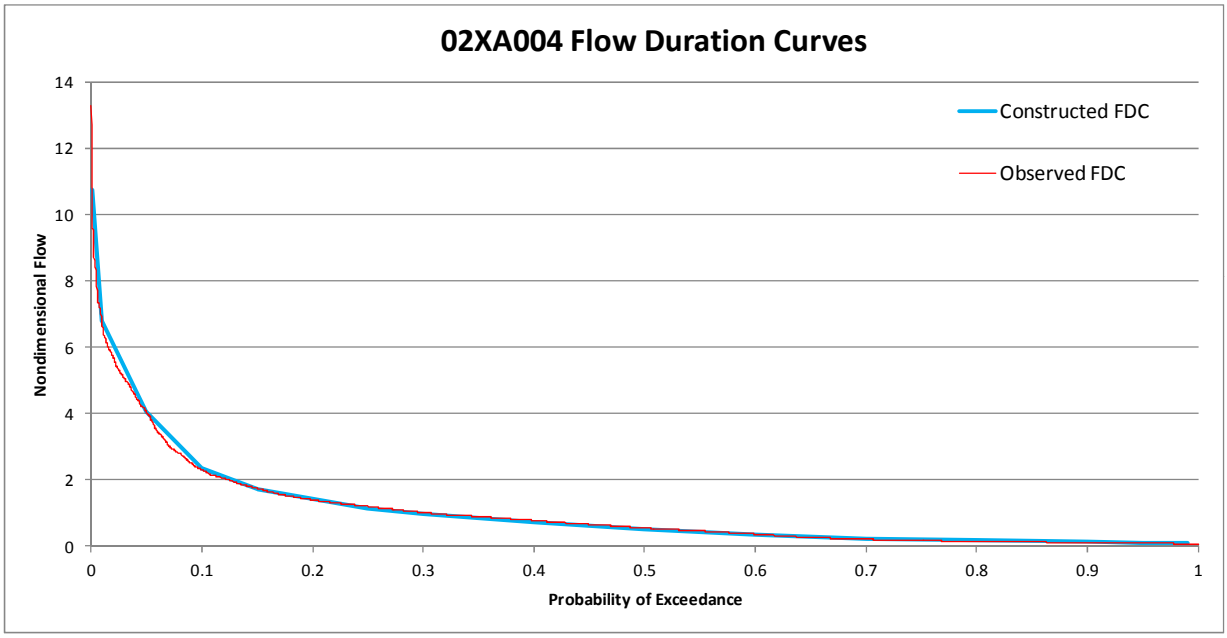
Location	Drainage Area DA (km^2)	Swamp Area SW Fraction	Forest Area AF Fraction	On-Channel Lake Storage AON Fraction	Off-Channel Lake Area AOFF Fraction	Total Lake Area AL Fraction	Barren Area AB Fraction	Fraction of Watershed Occupied by Lakes and Swamps FLSAR --	Fraction of Area Controlled by Lakes and Swamps FACLS --	Lakes and Swamps Factor LSF --	Lake Attenuation Factor LAF --	Latitude LAT (m)	Longitude LONG (m)	Basin Perimeter P (m)	Shape Factor SH --	Stream Length LEN (m)	Average Elevation AVEL (m)	Stream Slope SL --
02XA003	4478	0.0160	0.8907	0.0070	0.0574	0.0644	0.0288	0.0804	0.6022	1.552	50	5827490	543659	640399	2680	274561	469.5	0.0012
02XA004	2057	0.0957	0.8145	0.0046	0.0544	0.0590	0.0308	0.1547	0.5779	1.480	50	5809440	704923	294404	1818	96829	418.0	0.0017
02YA002	37	0.0003	0.4229	0.1023	0.0349	0.1373	0.4399	0.1373	0.9623	1.892	347	5721210	1010520	28374	1312	13371	110.5	0.0143
03NE001	76	0.0001	0.0940	0.0692	0.0681	0.1373	0.7687	0.1373	1.0000	1.931	310	6250550	545225	41289	1330	17670	267.0	0.0233
03NE002	25	0.0004	0.7329	0.1128	0.0128	0.1256	0.1415	0.1256	0.8965	1.830	333	6244400	559168	24695	1385	9754	82.0	0.0062
03NE011	155	0.0001	0.3936	0.0337	0.0620	0.0957	0.5107	0.0957	0.7048	1.649	81	6247700	551051	81995	1842	36723	257.5	0.0117
03NE012	15	0.0007	0.8360	0.0402	0.0026	0.0429	0.1212	0.0429	0.3606	1.329	49	6241910	558390	20957	1507	8397	77.5	0.0085
03NF001	7307	0.0049	0.4603	0.0132	0.0900	0.1032	0.4316	0.1081	0.8288	1.770	50	6121020	539696	693730	2272	193232	276.0	0.0023
03NG001	8926	0.0417	0.6922	0.0156	0.0737	0.0893	0.1768	0.1310	0.9870	1.921	50	6061830	516931	740923	2196	280127	318.5	0.0014
03OC003	15885	0.1298	0.6980	0.0719	0.0748	0.1467	0.0255	0.2765	1.0000	1.862	270	5820540	367592	928664	2063	291243	617.5	0.0009
03OD007	1776	0.0663	0.6969	0.0253	0.1315	0.1568	0.0801	0.2231	0.9373	1.822	126	5946950	512388	306482	2036	145202	508.0	0.0025
03OE003	2219	0.0263	0.8477	0.0443	0.0816	0.1259	0.0000	0.1522	1.0000	1.924	366	5825070	649728	323151	1921	106548	377.5	0.0014
03OE010	71	0.0055	0.9299	0.0388	0.0256	0.0644	0.0002	0.0699	0.9944	1.959	115	5929120	672448	53756	1791	27496	142.0	0.0047
03OE011	800	0.1392	0.6304	0.0417	0.1012	0.1430	0.0874	0.2822	0.9458	1.801	122	5906240	579879	192997	1910	92975	397.5	0.0011
03PB002	4541	0.0227	0.8111	0.0226	0.1245	0.1471	0.0192	0.1698	0.9735	1.887	50	6011820	554134	466647	1939	174135	307.0	0.0017
03QC001	10705	0.0881	0.7342	0.0142	0.0702	0.0844	0.0933	0.1725	0.8494	1.756	50	5884990	778646	735129	1989	252818	248.0	0.0017
03QC002	2312	0.0498	0.8830	0.0001	0.0302	0.0303	0.0369	0.0801	0.3041	1.243	50	5838900	890457	278859	1624	81039	259.5	0.0054
02UC002	18957	0.0274	0.8729	0.0073	0.0848	0.0921	0.0076	0.1195	0.6537	1.581	50	5735900	263536	1223230	2488	396028	341.5	0.0016
02UC003	3356	0.0279	0.8519	0.0068	0.0996	0.1064	0.0138	0.1343	0.8582	1.786	50	5821270	217123	488329	2360	120840	552.5	0.0010
02UC005	459	0.0000	0.9199	0.0261	0.0539	0.0801	0.0000	0.0801	1.0000	1.960	255	5596940	298813	107361	1403	54056	360.0	0.0109
02UC006	679	0.0020	0.9288	0.0178	0.0467	0.0646	0.0046	0.0666	0.7740	1.736	117	5593040	294656	136327	1464	62562	335.5	0.0102
02VA001	683	0.0062	0.9452	0.0041	0.0404	0.0446	0.0040	0.0507	0.3734	1.336	50	5599150	379769	148337	1590	86732	322.0	0.0063
02VB003	7531	0.0041	0.9080	0.0166	0.0652	0.0818	0.0061	0.0858	0.9670	1.923	140	5695060	361216	823896	2658	305471	416.5	0.0023
02VB004	7140	0.0043	0.9067	0.0165	0.0662	0.0827	0.0063	0.0870	1.0000	1.956	154	5699860	359250	712736	2362	256818	479.0	0.0023
02VC001	12941	0.0219	0.8787	0.0185	0.0725	0.0910	0.0084	0.1129	0.7368	1.672	35	5733030	460307	1277430	3144	456636	308.0	0.0012
02VC002	6568	0.0312	0.8476	0.0290	0.0840	0.1130	0.0082	0.1442	0.8827	1.806	137	5785210	449097	740958	2560	206845	512.0	0.0006
02WA001	2056	0.0111	0.8751	0.0071	0.0857	0.0928	0.0210	0.1039	0.6666	1.604	50	5636080	542615	345739	2135	166801	328.5	0.0033
02WA002	5598	0.0072	0.8983	0.0081	0.0782	0.0863	0.0082	0.0935	0.7063	1.651	50	5685240	535431	682601	2555	265547	289.5	0.0019
02WA003	150	0.1444	0.2914	0.0208	0.0462	0.0670	0.4972	0.2114	0.4848	1.342	50	5580990	565055	68951	1578	43227	77.0	0.0020
02WB001	15829	0.0062	0.8836	0.0073	0.0848	0.0921	0.0181	0.0983	0.5317	1.468	50	5734060	557644	1079740	2403	420630	317.0	0.0015
02WB002	11407	0.0068	0.8895	0.0060	0.0857	0.0917	0.0120	0.0985	0.5660	1.503	50	5763500	546768	746824	1958	286808	383.5	0.0017
02WB003	15383	0.0056	0.8938	0.0064	0.0842	0.0906	0.0100	0.0962	0.5338	1.471	50	5738420	556536	992175	2240	383467	331.5	0.0016
02WC001	2940	0.0014	0.7646	0.0235	0.1274	0.1509	0.0831	0.1523	1.0000	1.924	65	5630790	705511	401760	2075	173151	234.5	0.0025
02WC002	5230	0.0066	0.8963	0.0076	0.0800	0.0875	0.0095	0.0941	0.5901	1.531	50	5677350	654805	609776	2361	255899	290.5	0.0020
02XA006	19267	0.0223	0.8895	0.0126	0.0615	0.0741	0.0141	0.0964	0.7582	1.703	50	5768350	649070	1520570	3067	545246	334.0	0.0011
02XA007	12109	0.0305	0.8778	0.0116	0.0588	0.0703	0.0214	0.1008	0.8804	1.827	50	5801720	622324	1189660	3027	385023	456.0	0.0009
02XB001	5725	0.0452	0.9148	0.0037	0.0339	0.0376	0.0023	0.0829	0.1799	1.110	50	5782790	763991	434365	1607	167719	277.5	0.0026
02XB002	1025	0.0018	0.9136	0.0283	0.0556	0.0839	0.0007	0.0857	1.0000	1.957	108	5750050	817161	195030	1706	85203	231.5	0.0038
02XC001	5524	0.0860	0.8136	0.0144	0.0317	0.0461	0.0543	0.1321	0.3312	1.232	50	5797580	833677	505655	1905	176230	206.0	0.0022
Mean	5691	0.0304	0.7802	0.0246	0.0673	0.0918	0.0975	0.1222	0.7538	1.684	107	5828091	563313	520100	2058	189822	321.0	0.0039
Maximum	19267	0.1444	0.9452	0.1128	0.1315	0.1568	0.7687	0.2822	1.0000	1.960	366	6250550	1010520	1520570	3144	545246	617.5	0.0233
Minimum	15	0.0000	0.0940	0.0001	0.0026	0.0303	0.0000	0.0429	0.1799	1.110	35	5580990	217123	20957	1312	8397	77.0	0.0006

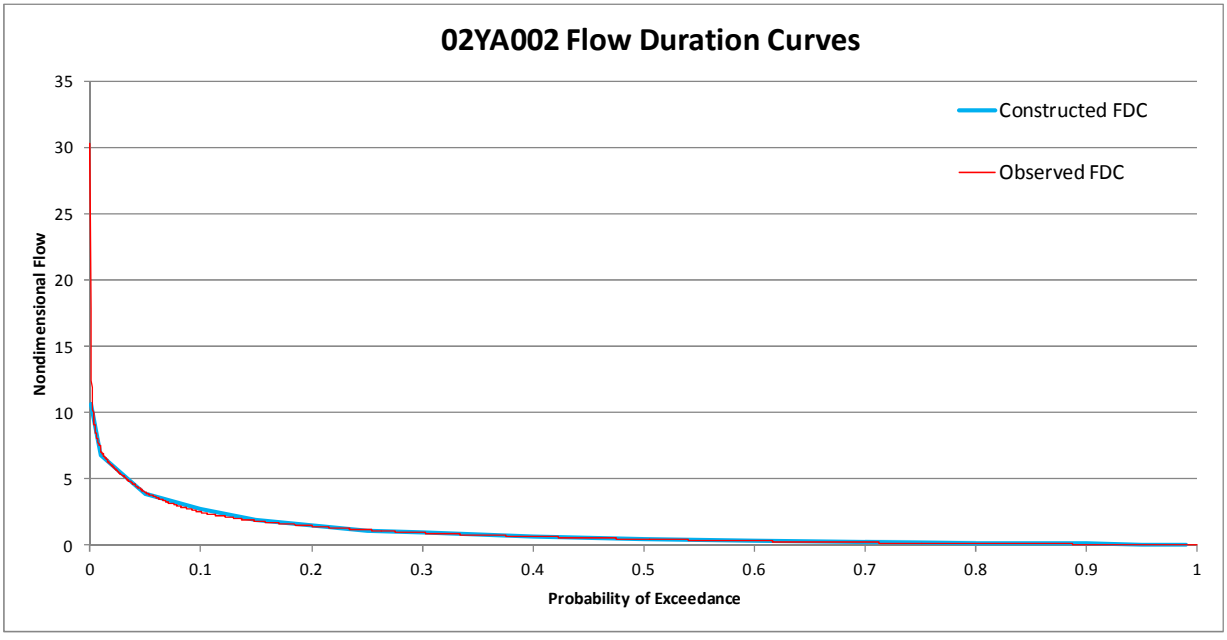
Table C-4
Physiographic Parameters of Potential Project Sites

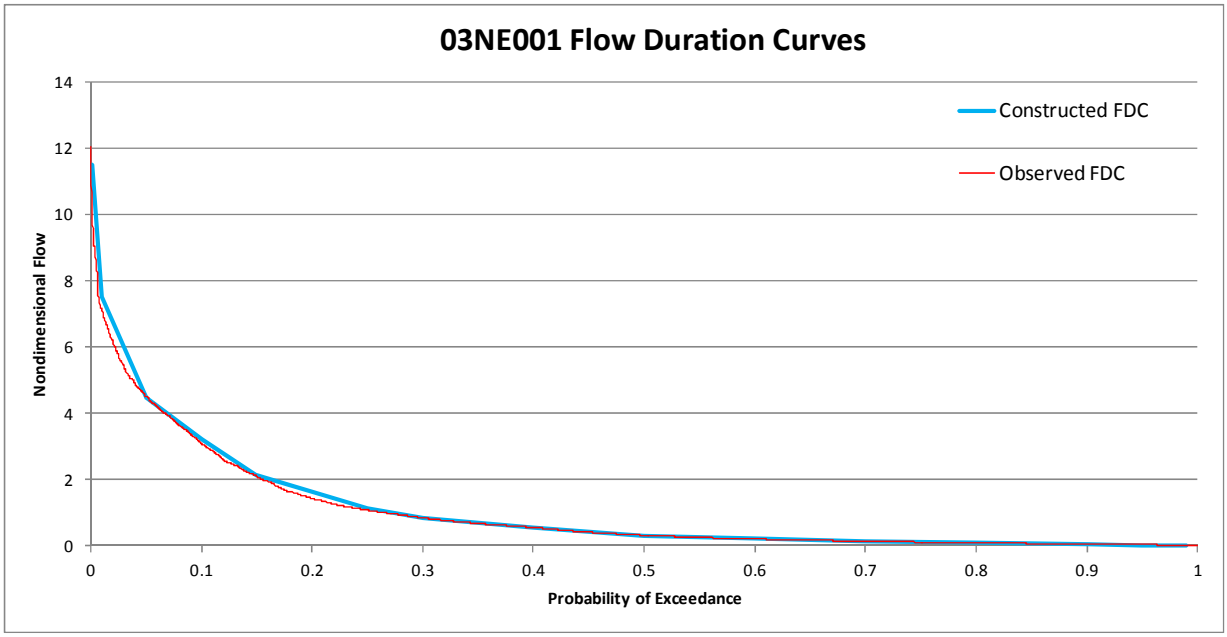
Location	Drainage Area DA (km^2)	Swamp Area SW Fraction	Forest Area AF Fraction	On-Channel Lake Storage AON Fraction	Off-Channel Lake Area AOFF Fraction	Total Lake Area AL Fraction	Barren Area AB Fraction	Fraction of Watershed Occupied by Lakes and Swamps FLSAR - -	Fraction of Area Controlled by Lakes and Swamps FACLS - -	Lakes and Swamps Factor LSF - -	Lake Attenuation Factor LAF - -	Latitude LAT (m)	Longitude LONG (m)	Basin Perimeter P (m)	Shape Factor SH - -	Stream Length LEN (m)	Average Elevation AVEL (m)	Stream Slope SL - -
Site 1	70	0.0001	0.0715	0.0457	0.0247	0.0705	0.8581	0.0705	0.9217	1.885	158	6096410	744425	36908	1239	14561	191.0	0.0093
Site 3	229	0.0195	0.9127	0.0245	0.0433	0.0678	0.0000	0.0873	0.9726	1.928	138	5838253	930888	81992	1517	31670	136.5	0.0063
Site 4	459	0.0129	0.8649	0.0362	0.0451	0.0813	0.0409	0.0942	1.0000	1.953	114	5811532	960179	130533	1705	60427	154.5	0.0045
Site 5	609	0.0196	0.9082	0.0332	0.0252	0.0584	0.0137	0.0781	0.9999	1.961	232	5865314	933659	175909	1996	82855	193.5	0.0042
Site 7	609	0.0335	0.9413	0.0000	0.0133	0.0133	0.0120	0.0467	0.1810	1.141	50	5883088	913893	134292	1524	54945	234.0	0.0058
Site 8	2403	0.0415	0.7061	0.0158	0.0550	0.0708	0.1816	0.1123	0.6073	1.537	40	5810185	903839	358122	2045	154854	238.0	0.0028
Site 9	2379	0.0419	0.7033	0.0160	0.0555	0.0715	0.1834	0.1133	0.6131	1.543	41	5809975	903370	349625	2007	151673	242.5	0.0028
Site 11	5623	0.0046	0.5466	0.0122	0.0884	0.1005	0.3483	0.1051	0.9171	1.862	50	6112667	555919	736782	2082	244907	262.0	0.0020
Site 12	125	0.0001	0.5090	0.0855	0.0538	0.1394	0.3517	0.1394	1.0000	1.930	274	6137323	649531	72483	1818	35086	150.5	0.0080
Site MK S-1	102	0.0001	0.1566	0.0485	0.0169	0.0654	0.7780	0.0654	1.0000	1.967	163	6098917	745005	49656	1377	20511	137.5	0.0118
Site MK S-2	74	0.0001	0.0774	0.0431	0.0233	0.0664	0.8562	0.0664	0.8685	1.833	140	6096760	744484	38935	1269	15805	163.5	0.0121
Site ALX	2312	0.0498	0.8830	0.0001	0.0302	0.0303	0.0369	0.0801	0.3041	1.243	50	5838900	890457	278859	1624	81039	259.5	0.0054
Mean	1249	0.0186	0.6067	0.0301	0.0396	0.0696	0.3051	0.0882	0.7821	1.732	121	5949944	822971	203675	1684	79028	196.9	0.0063
Maximum	5623	0.0498	0.9413	0.0855	0.0884	0.1394	0.8581	0.1394	1.0000	1.967	274	6137323	960179	736782	2082	244907	262.0	0.0121
Minimum	70	0.0001	0.0715	0.0000	0.0133	0.0133	0.0000	0.0467	0.1810	1.141	40	5809975	555919	36908	1239	14561	136.5	0.0020

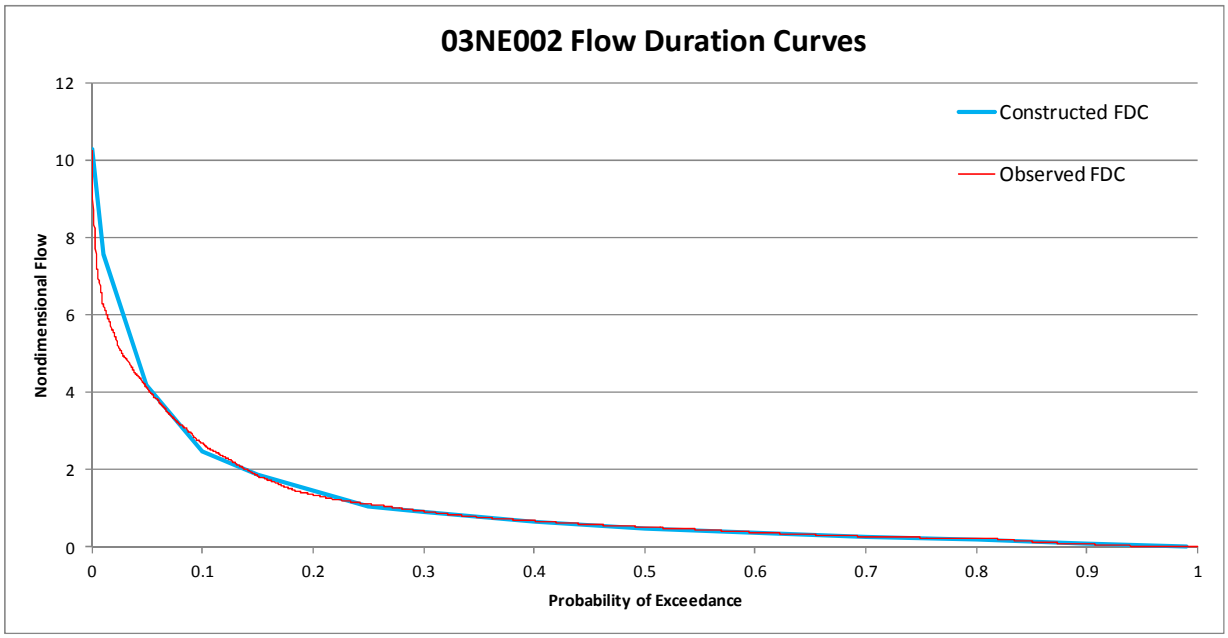
Percentile Flow	Prediction Equation	R^2	Standard error of the estimate
$LnQ_{0.1}$	2.6255-0.15027*Ln P-0.36307*Ln AL +0.04238*Ln AB +0.12587*Ln AVEL	0.70	0.137498
Ln Q_1	-15.65-0.07106*Ln LEN+1.1333* Ln LAT-0.31996*Ln AL+0.026987*Ln AB+0.14766*Ln FACLS	0.66	0.103826
Ln Q_5	-18.696-0.03548*Ln LEN-0.26283*Ln AL+1.3084*Ln LAT+0.05815*Ln AOFF+0.11758*Ln FACLS+0.012192*Ln AB	0.69	0.0633648
Ln Q_{10}	1.0721+0.05606*Ln SL-0.09343*LN AF-0.04074*LN AL	0.65	0.0541317
LnQ_{15}	0.77167-0.025281*Ln P-0.0797*Ln AF-0.03556*Ln FLSAR	0.69	0.0347564
Ln Q_{25}	0.7294+0.05336*Ln AOFF-0.03349*Ln LONG	0.48	0.0419709
Ln Q_{30}	18.094-0.06444*LN SL+0.13252*LN AL+0.06613*LN DA-1.1227*LN LAT-0.1162*LN LEN-0.08131*LN FLSAR	0.71	0.0480696
Ln Q_{40}	22.155+0.10289*LN P+0.25655*LN AL-0.1109*LN SL-1.3836*LN LAT-0.06284*LN AOFF-0.3597*LN SH-0.15171*LN FLSAR	0.83	0.059637
Ln Q_{50}	22.8328+0.13676*Ln P+0.11215*Ln AF+0.37909*Ln AL-1.5525*Ln LAT-0.09284*Ln AOFF-0.1284*Ln FACLS-0.015933*Ln AB-0.06214*Ln AVEL	0.89	0.0638064
Ln Q_{60}	35.38+0.13983*Ln AF+0.55945*Ln AL-0.26737*Ln FACLS-2.3695*Ln LAT-0.14005*Ln AOFF-0.025232*Ln AB+0.15309*Ln P-0.08325*Ln AVEL	0.86	0.0899744
Ln Q_{70}	21.85+0.14052*LN LEN+0.24752*LN AF+0.5507*LN AF-0.31337*LN FACLS-1.4456*LN LAT-0.17886*LN AVEL-0.03418*LN AB	0.76	0.140558
Ln Q_{80}	-1.1049+0.16953*Ln LEN+0.32538*Ln AF+0.5883*Ln AL-0.2757*Ln FACLS-0.20106*Ln AVEL-0.04173*Ln AB	0.75	0.160264
Ln Q_{90}	50.85+0.08566*LN LEN-0.04159*LN AB+0.5542*LN AL-3.488*LN LAT-0.20318*LN SL-0.2451*LN FACLS-0.2301*LN FLSAR	0.82	0.161599
Ln Q_{95}	71.55+0.23391*LN LEN-4.942*LN LAT-0.04801*LN AB-0.13938*LN SL+0.1901*LN AL	0.80	0.240009
Ln Q_{99}	133.26+0.41513*Ln LEN-9.192*Ln LAT+0.4416*Ln AVEL	0.77	0.427162

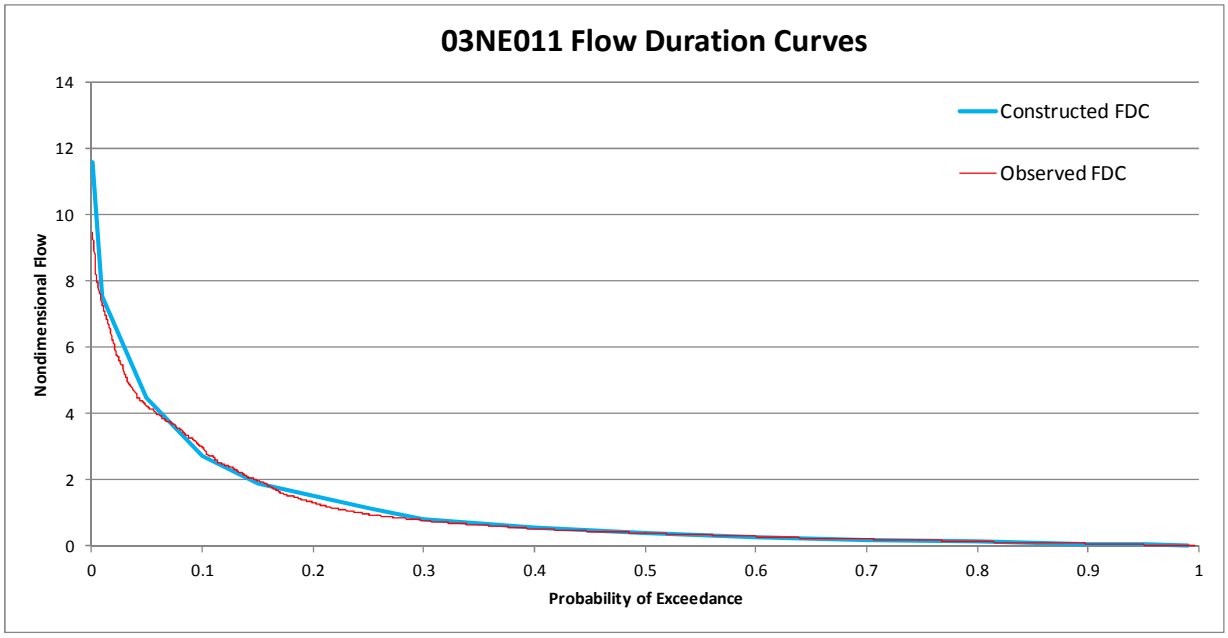

02XA003 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
2
4
6
8
10
12
14
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

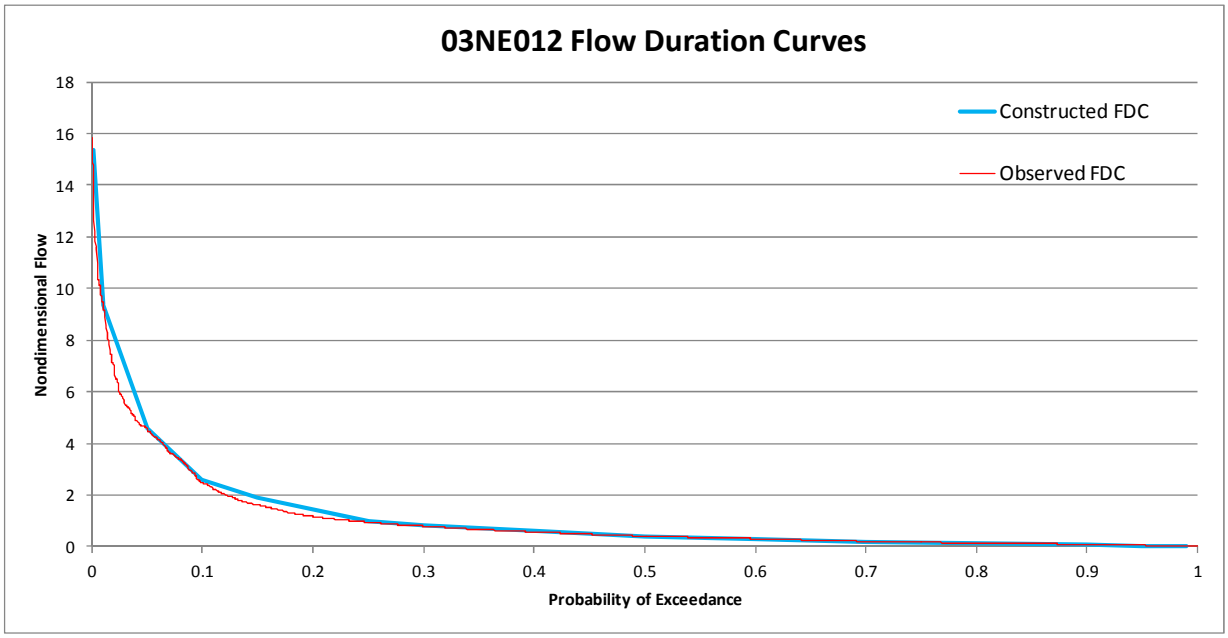

02XA004 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
2
4
6
8
10
12
14
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

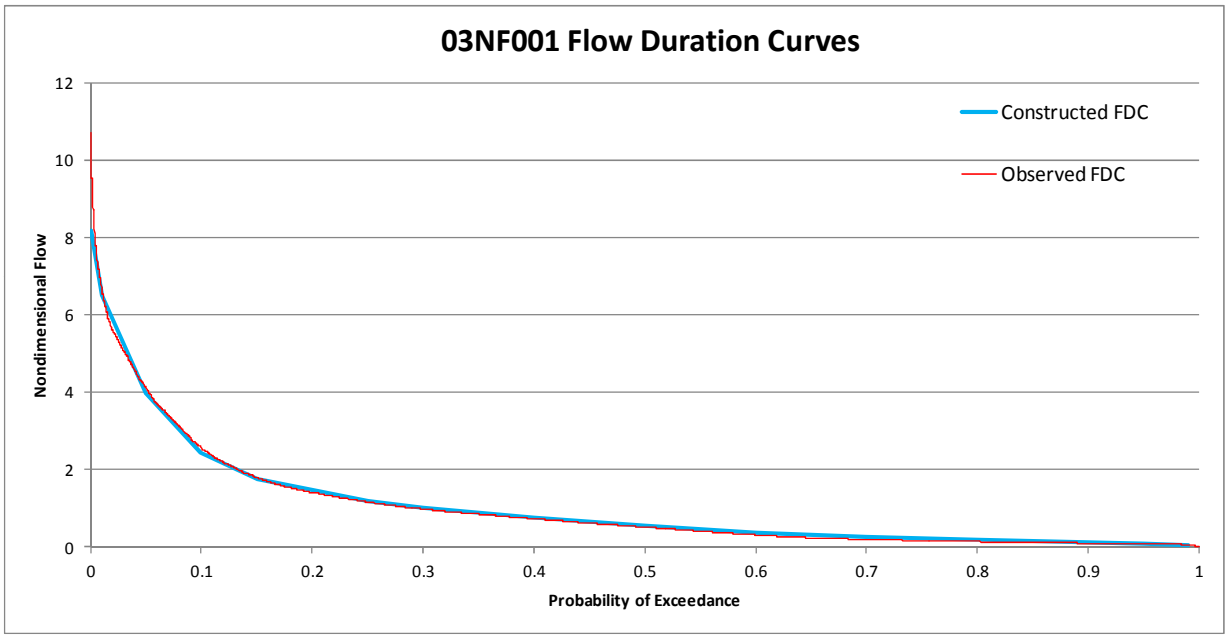

02YA002 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
5
10
15
20
25
30
35
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

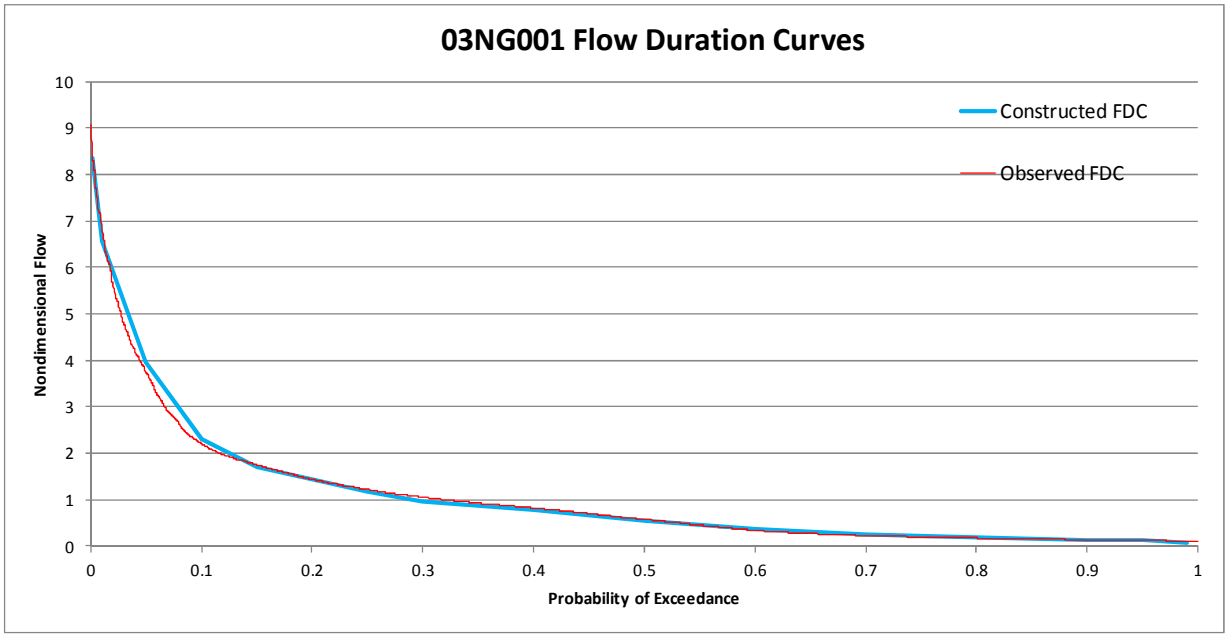

03NE001 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
2
4
6
8
10
12
14
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

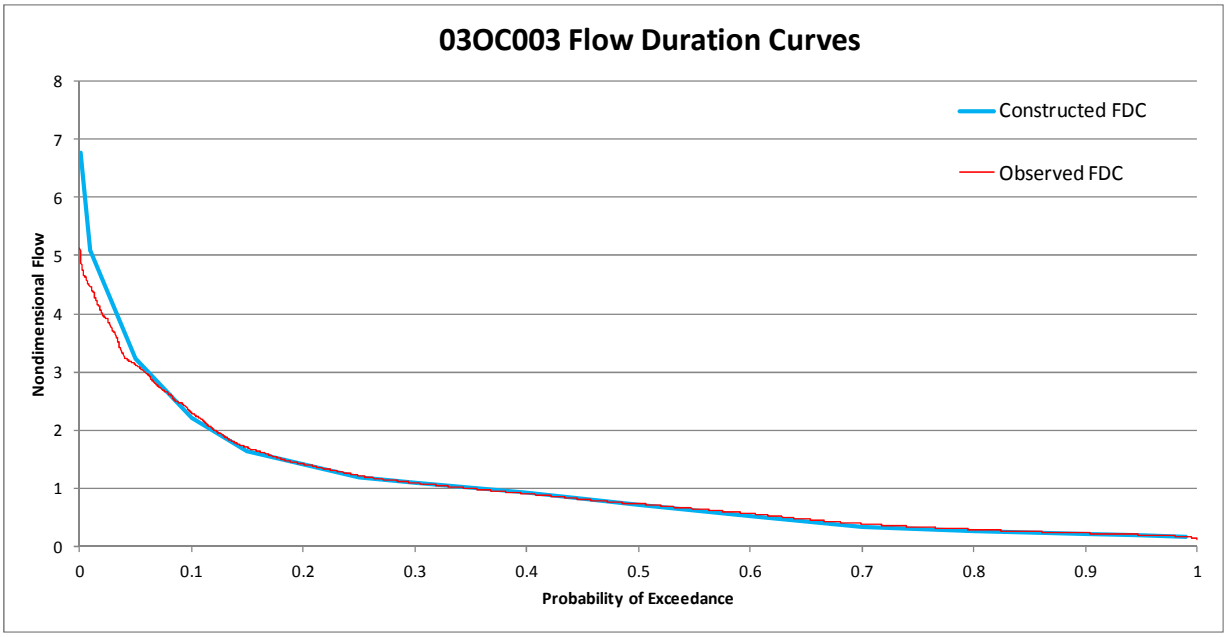

03NE002 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
2
4
6
8
10
12
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

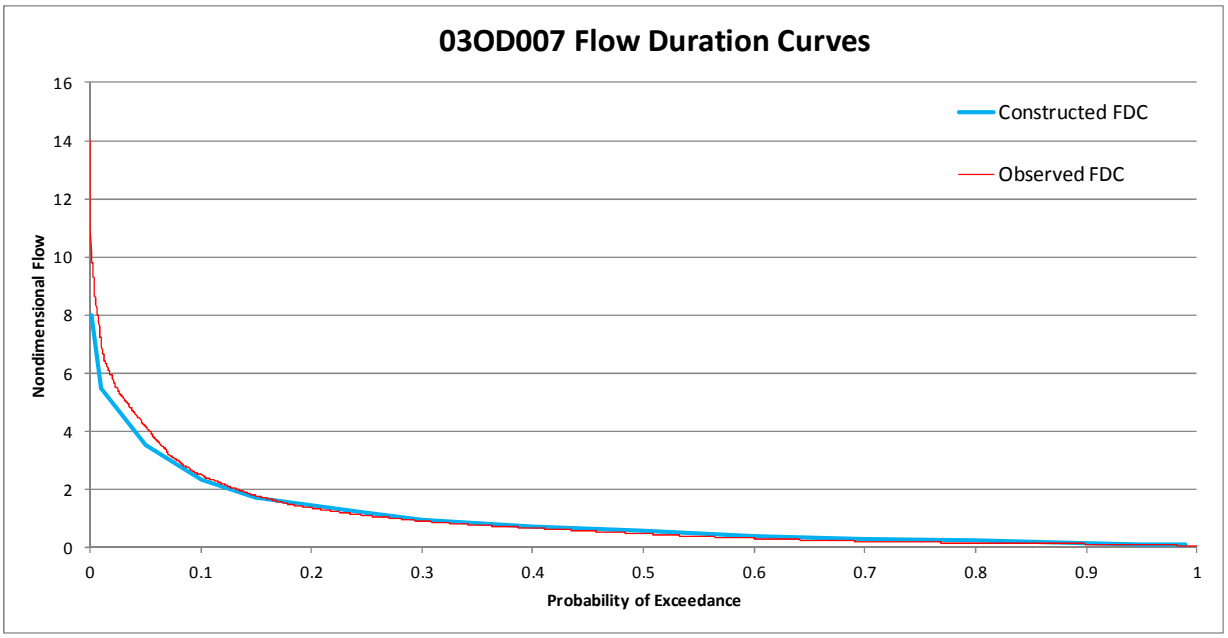

03NE011 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
2
4
6
8
10
12
14
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

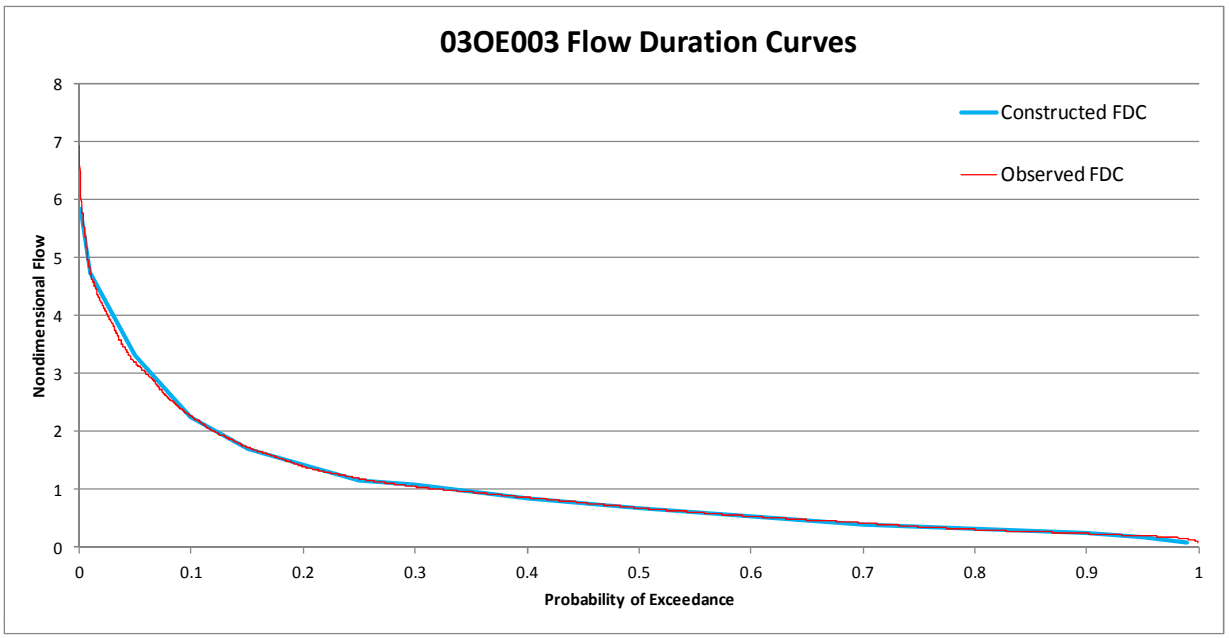

03NE012 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
2
4
6
8
10
12
14
16
18
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

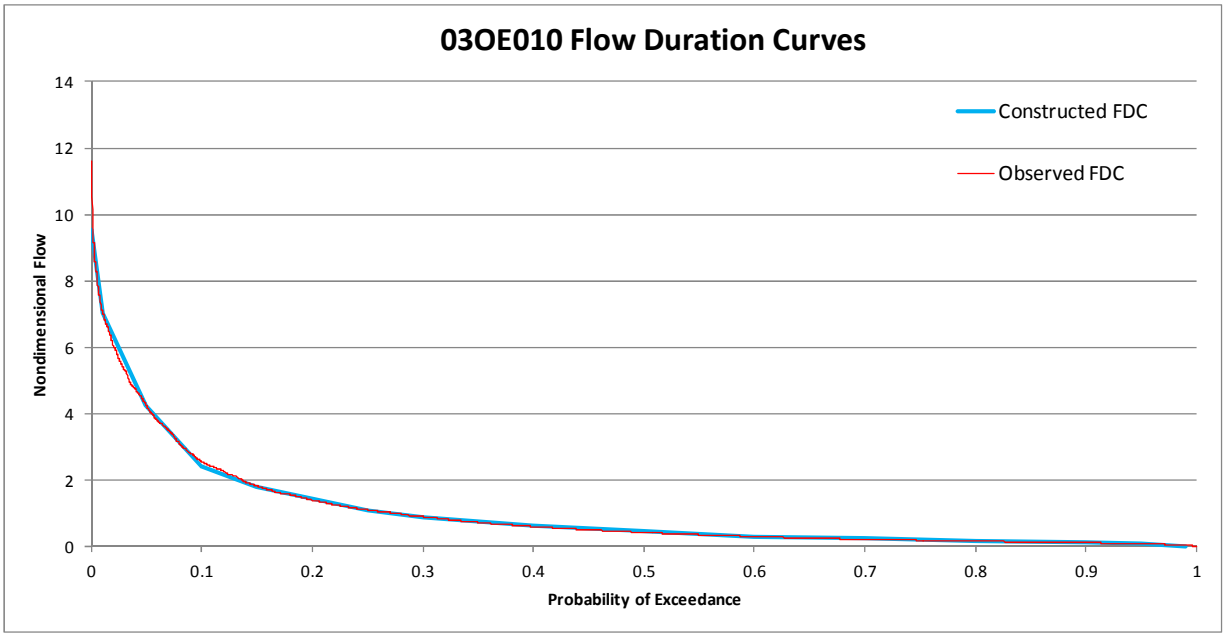

03NF001 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
2
4
6
8
10
12
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

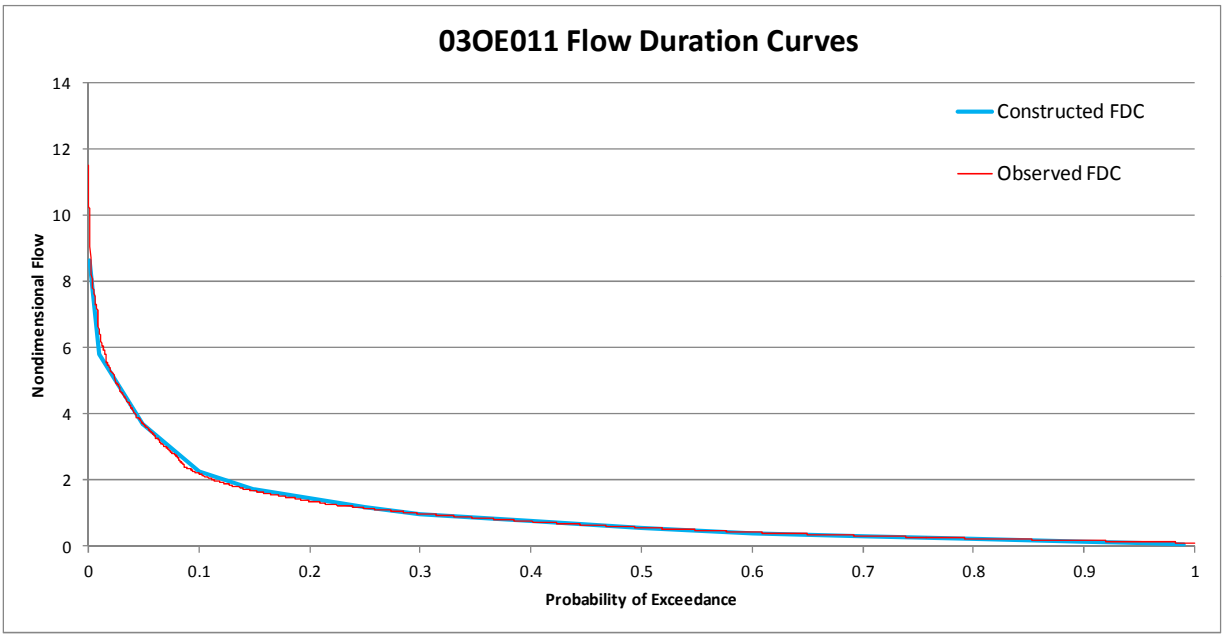

03NG001 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
1
2
3
4
5
6
7
8
9
10
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

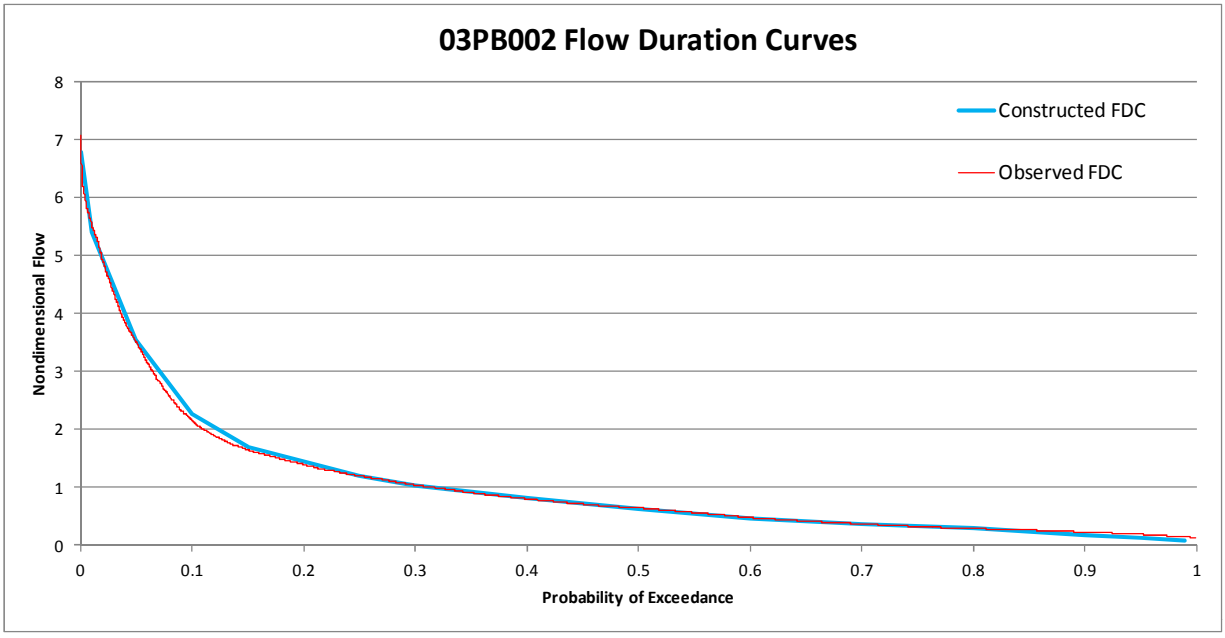

03OC003 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
1
2
3
4
5
6
7
8
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

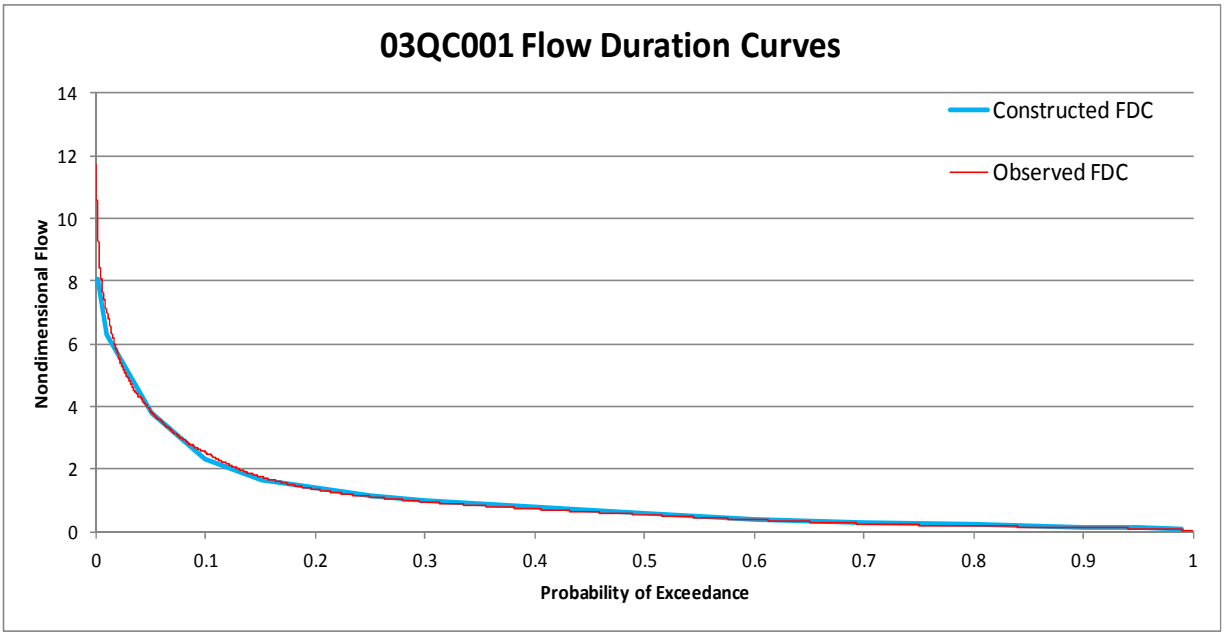

03OD007 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
2
4
6
8
10
12
14
16
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

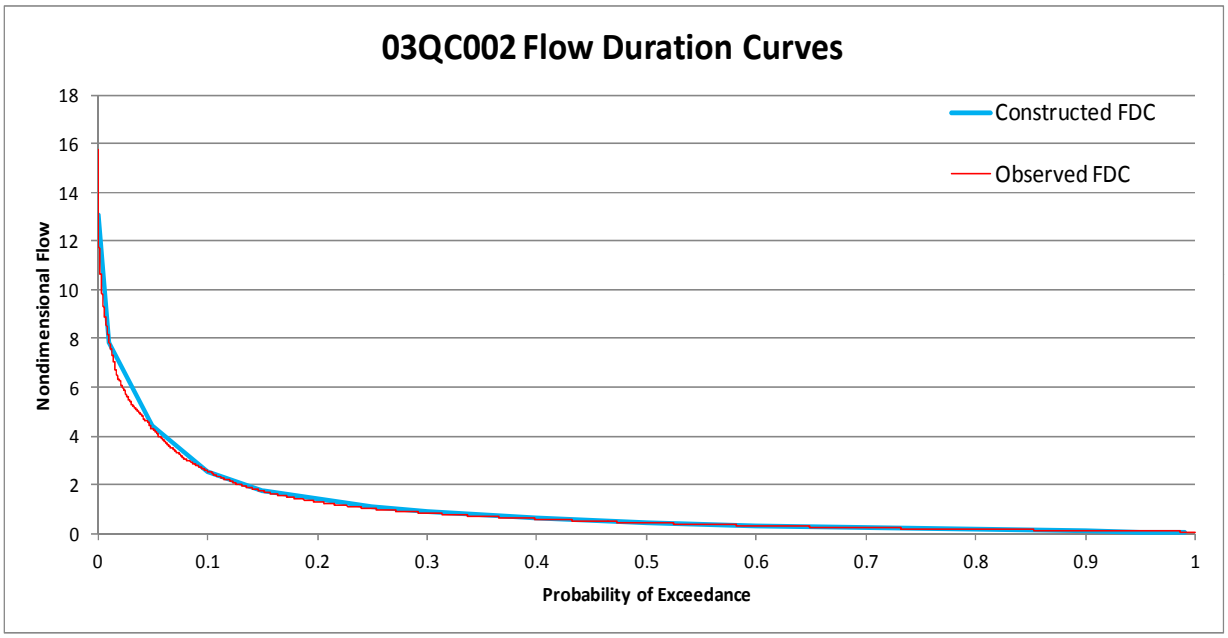

03OE003 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
1
2
3
4
5
6
7
8
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

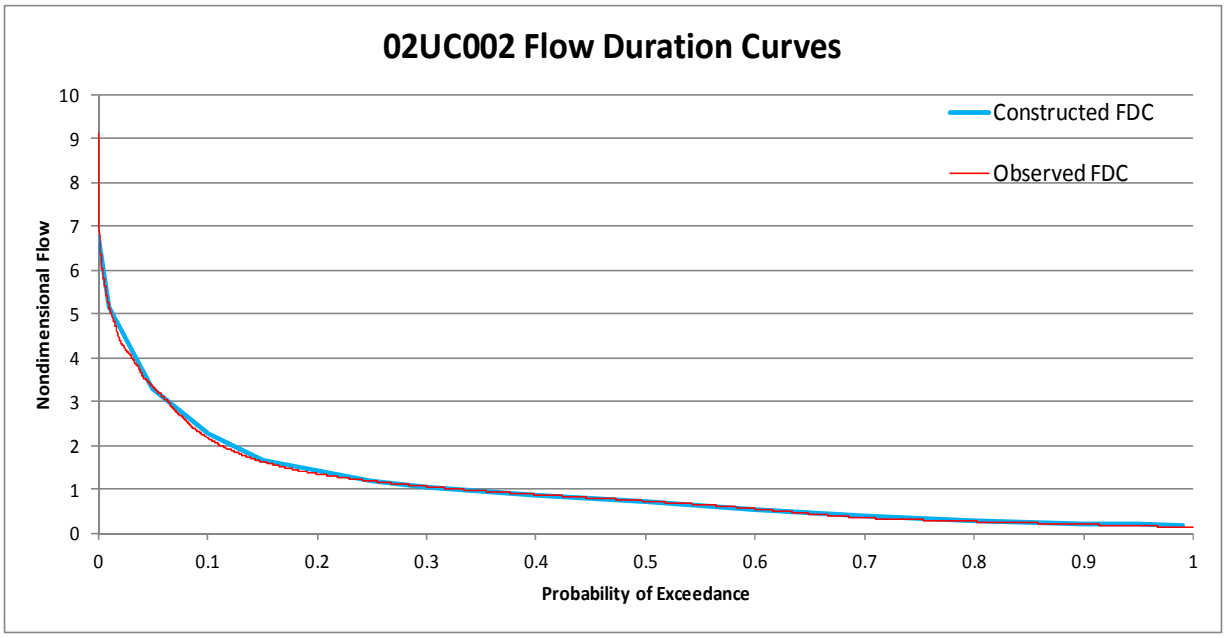

03OE010 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
2
4
6
8
10
12
14
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

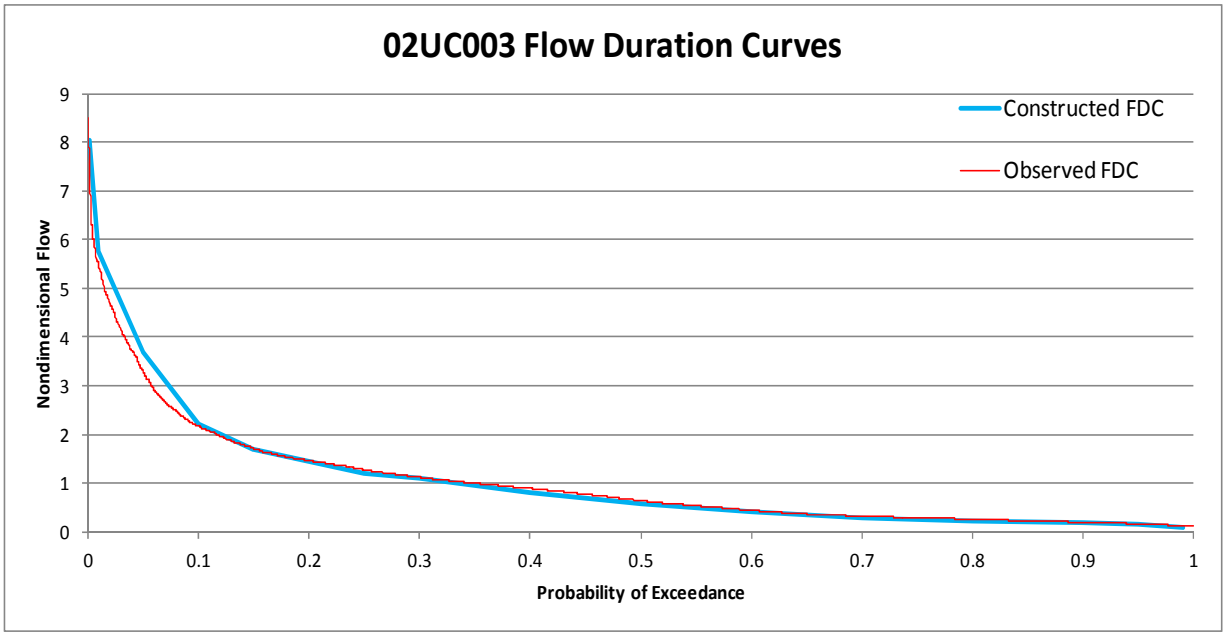

03OE011 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
2
4
6
8
10
12
14
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

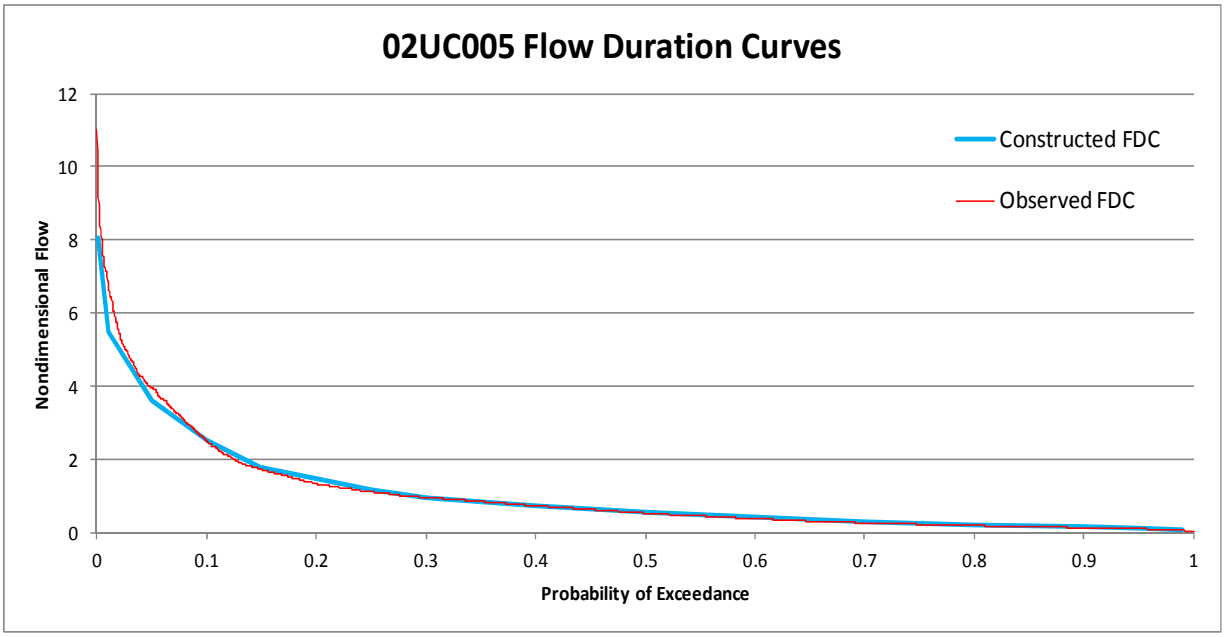

03PB002 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
1
2
3
4
5
6
7
8
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

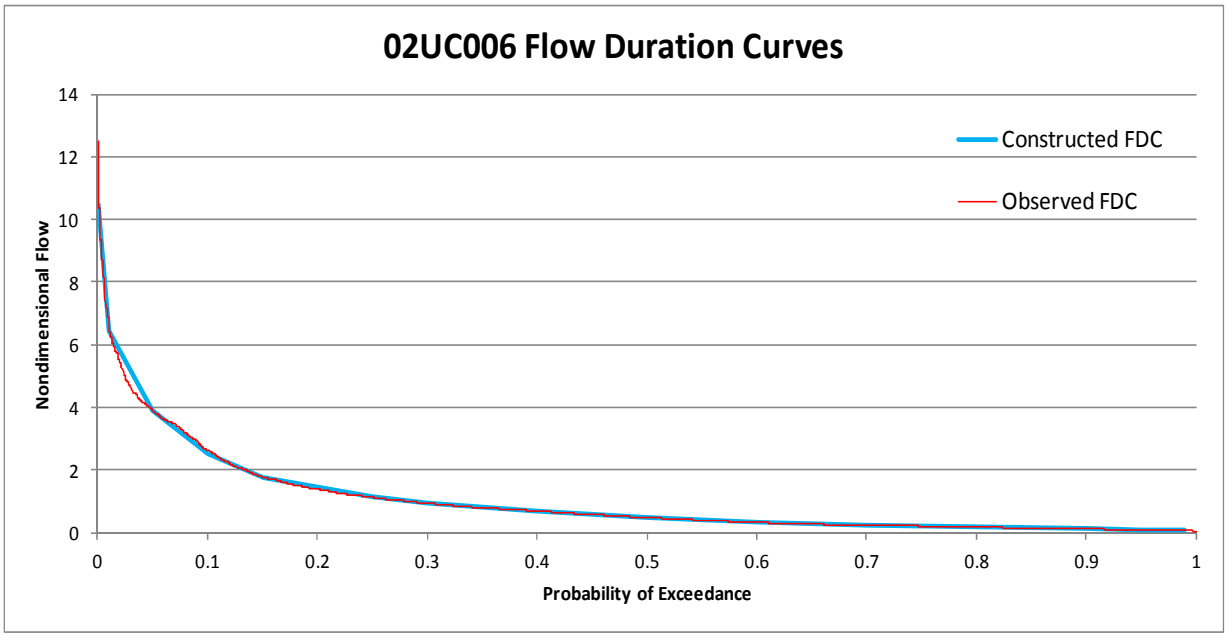

03QC001 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
2
4
6
8
10
12
14
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

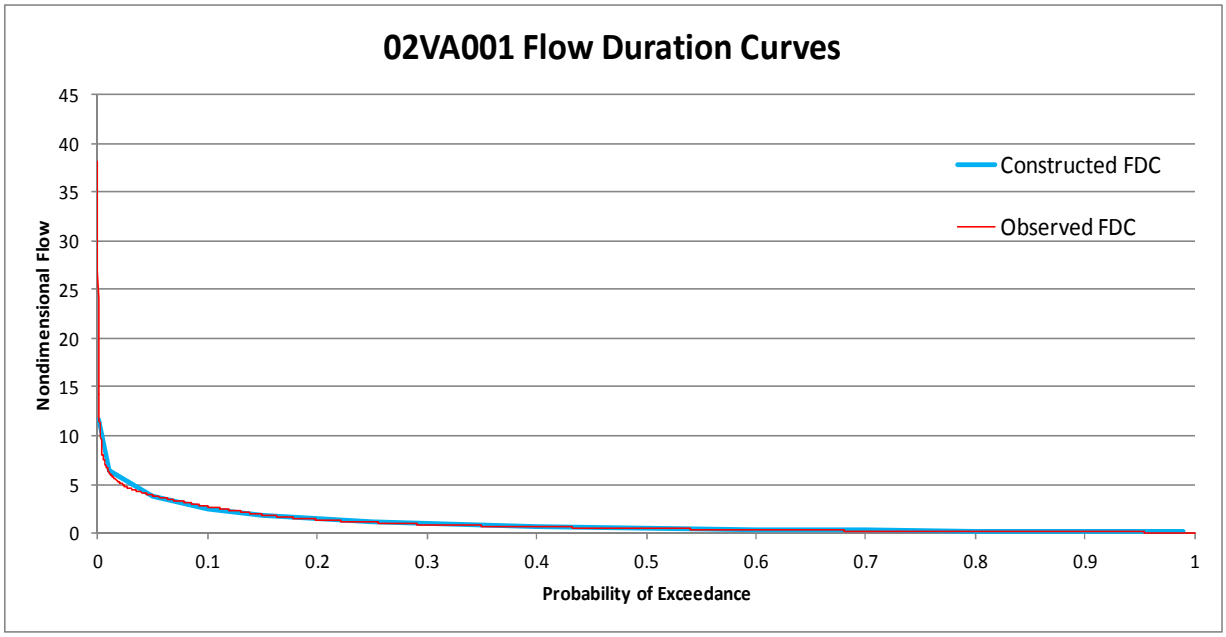

03QC002 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
2
4
6
8
10
12
14
16
18
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

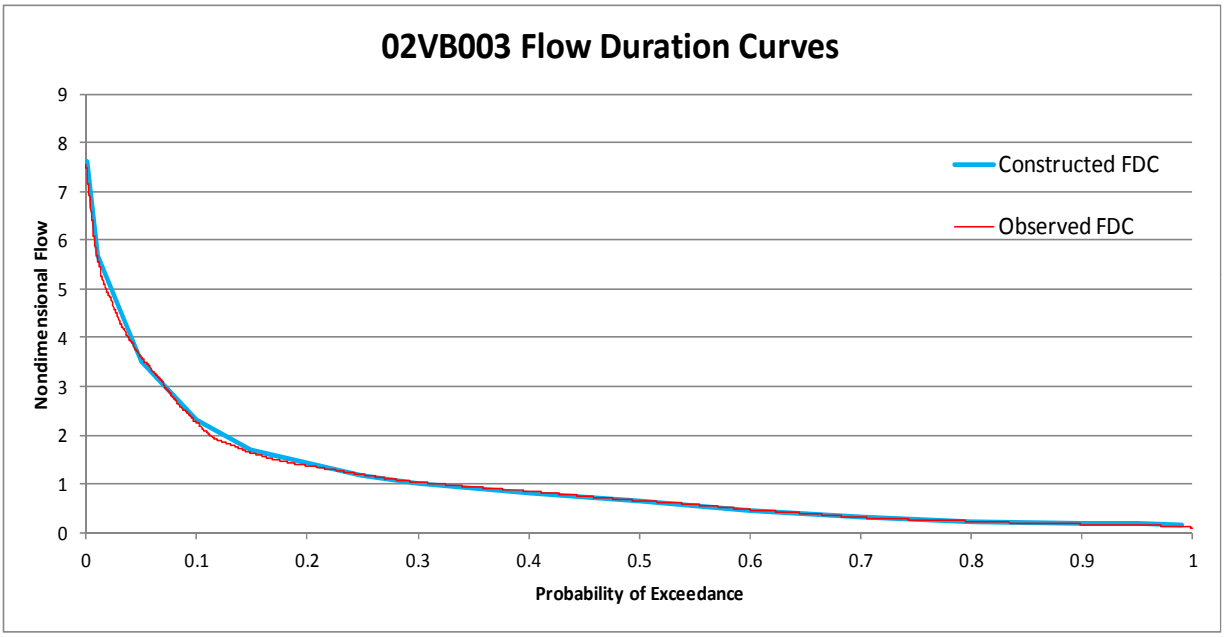

02UC002 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
1
2
3
4
5
6
7
8
9
10
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

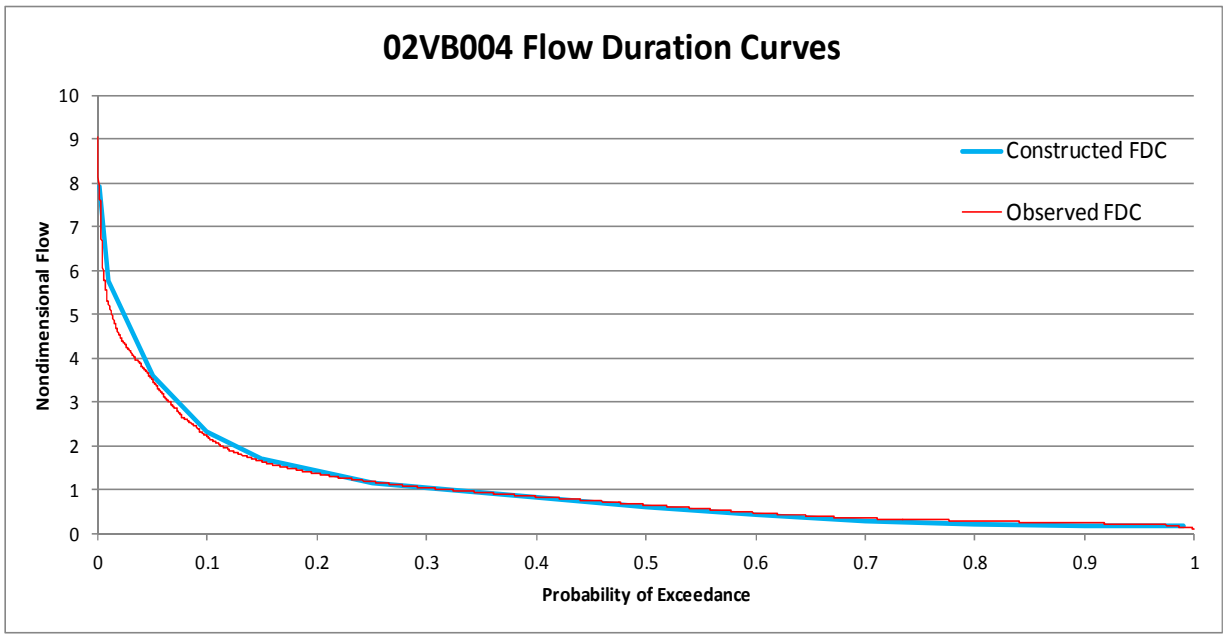

02UC003 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
0
1
2
3
4
5
6
7
8
9
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Probability of Exceedance

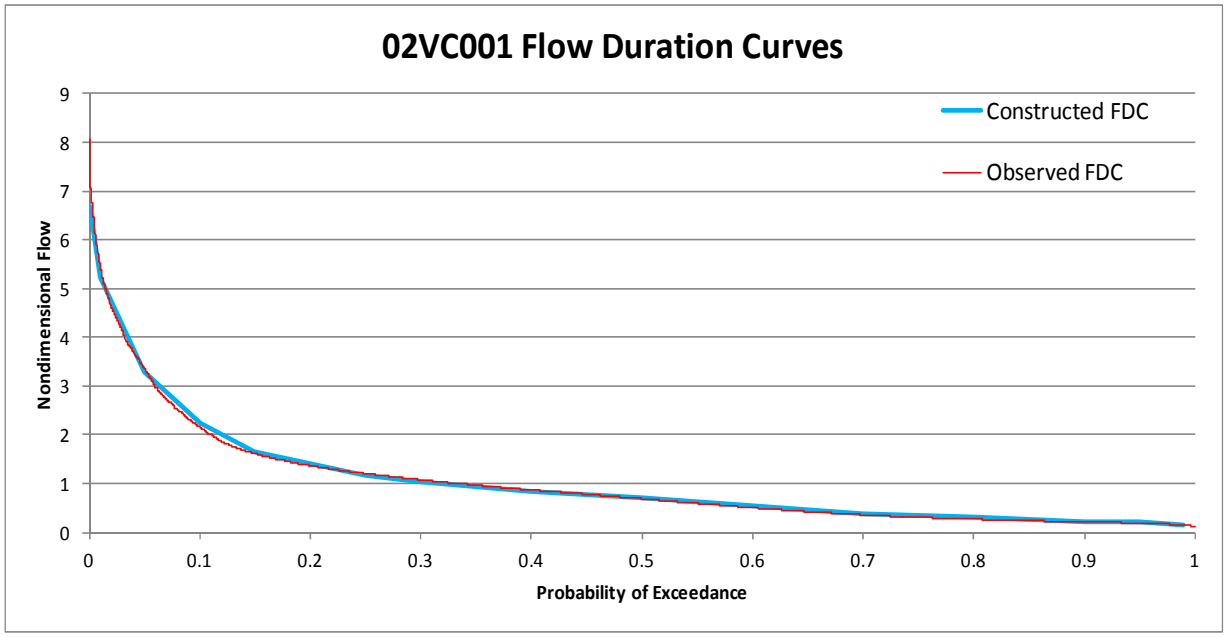

02UC005 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
0
2
4
6
8
10
12
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Probability of Exceedance

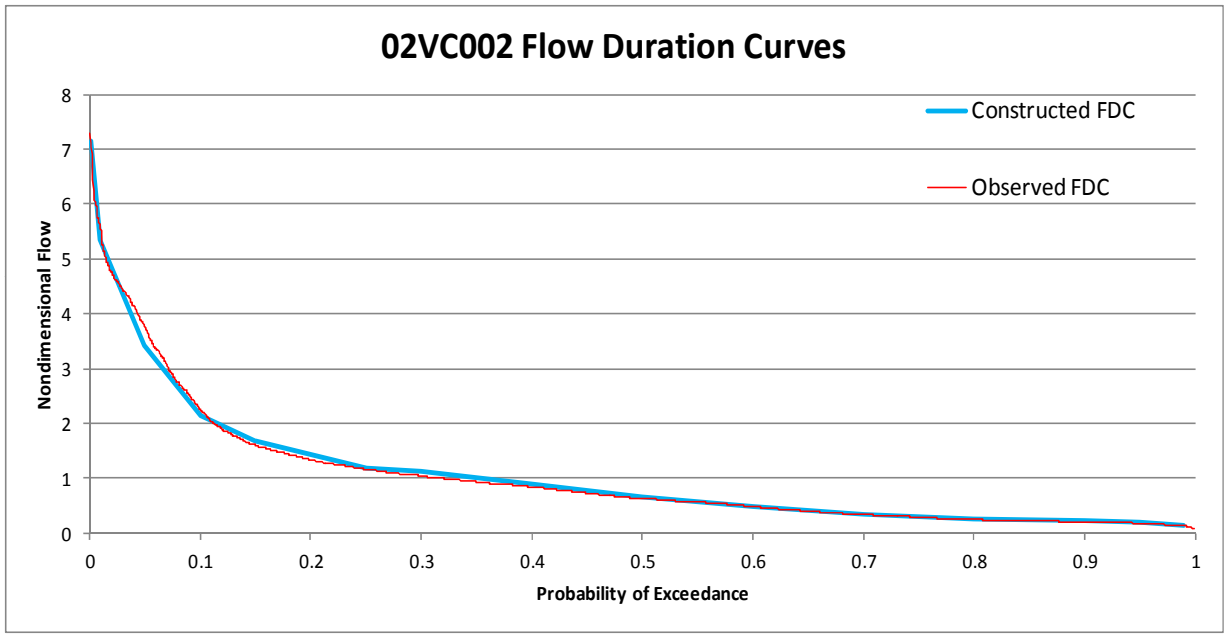

02UC006 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
0
2
4
6
8
10
12
14
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Probability of Exceedance

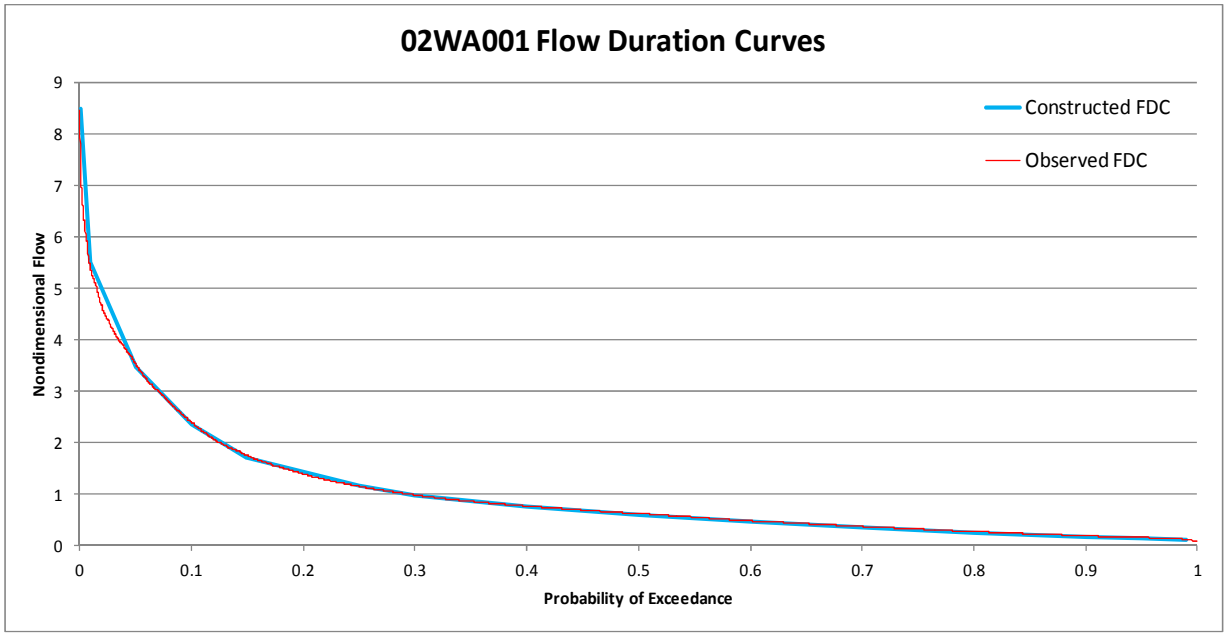

02VA001 Flow Duration Curves
Nondimensional Flow
Probability of Exceedance
Constructed FDC
Observed FDC
0
5
10
15
20
25
30
35
40
45
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

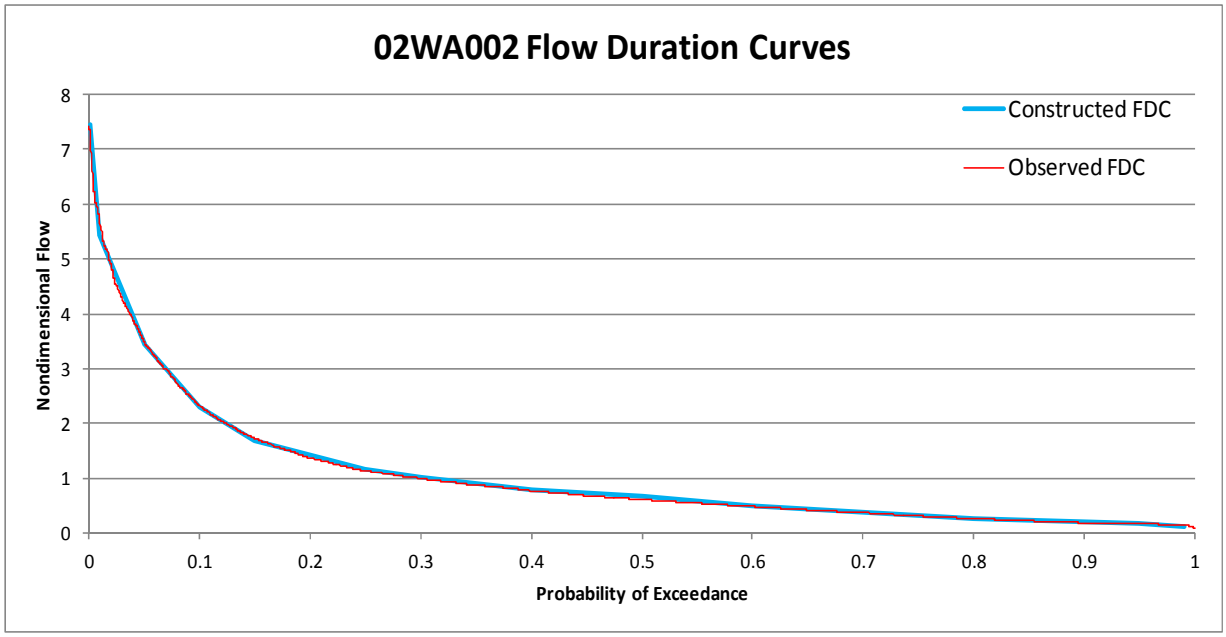

02VB003 Flow Duration Curves
Nondimensional Flow
Probability of Exceedance
Constructed FDC
Observed FDC
0
1
2
3
4
5
6
7
8
9
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

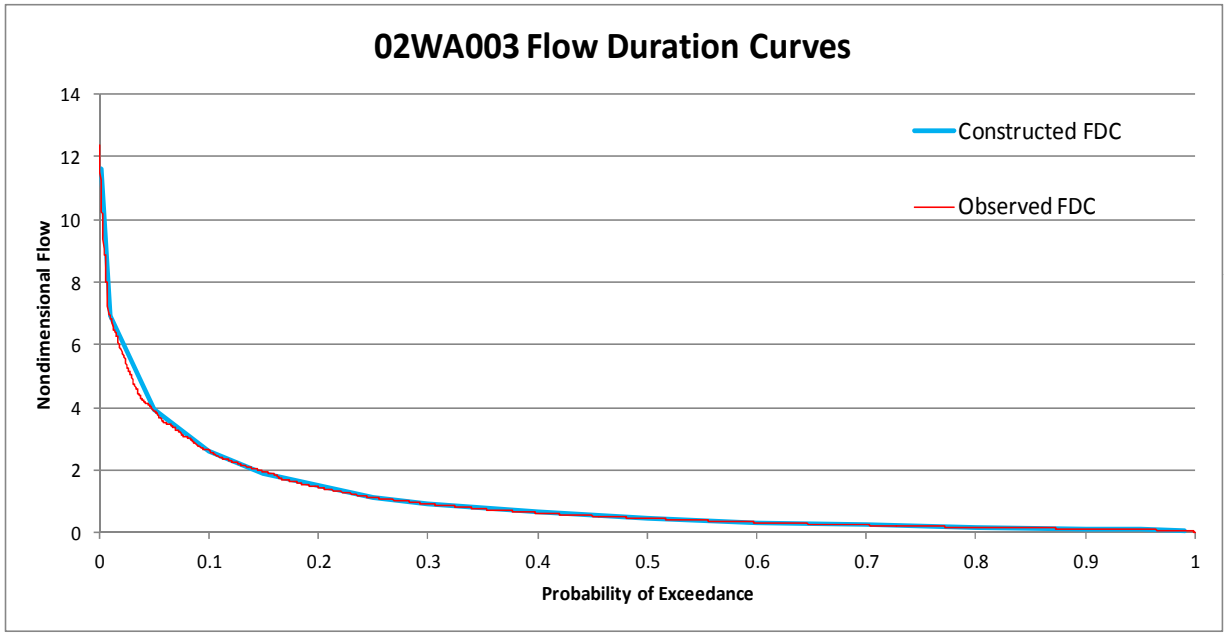

02VB004 Flow Duration Curves
Nondimensional Flow
Probability of Exceedance
Constructed FDC
Observed FDC
0
1
2
3
4
5
6
7
8
9
10
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

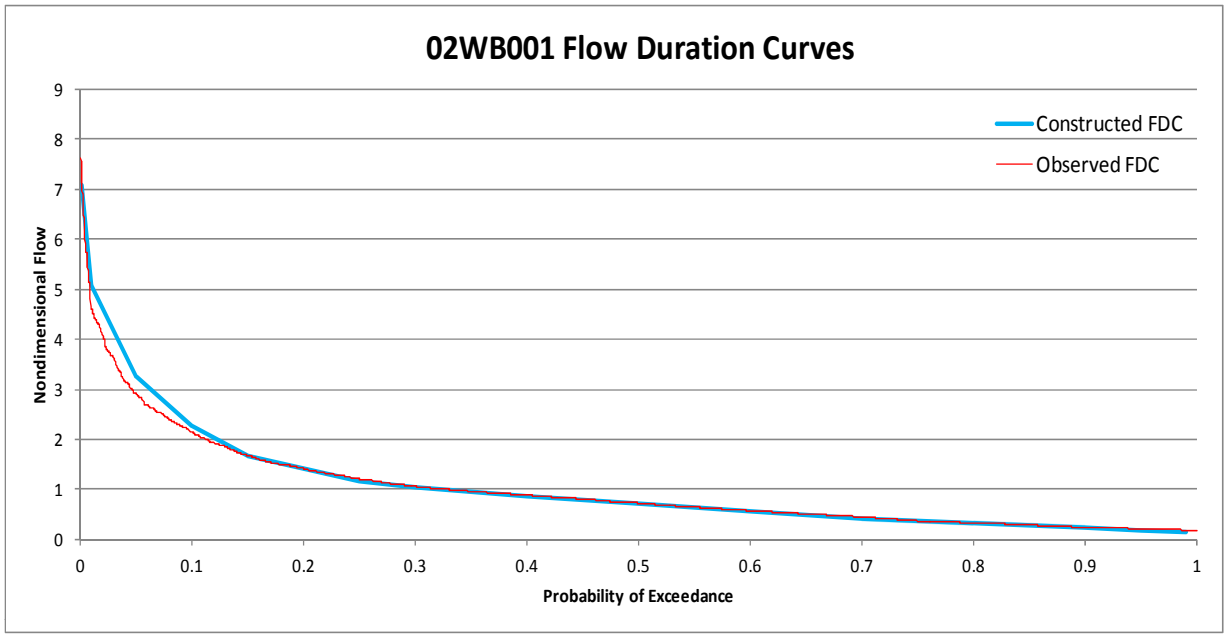

02VC001 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
1
2
3
4
5
6
7
8
9
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

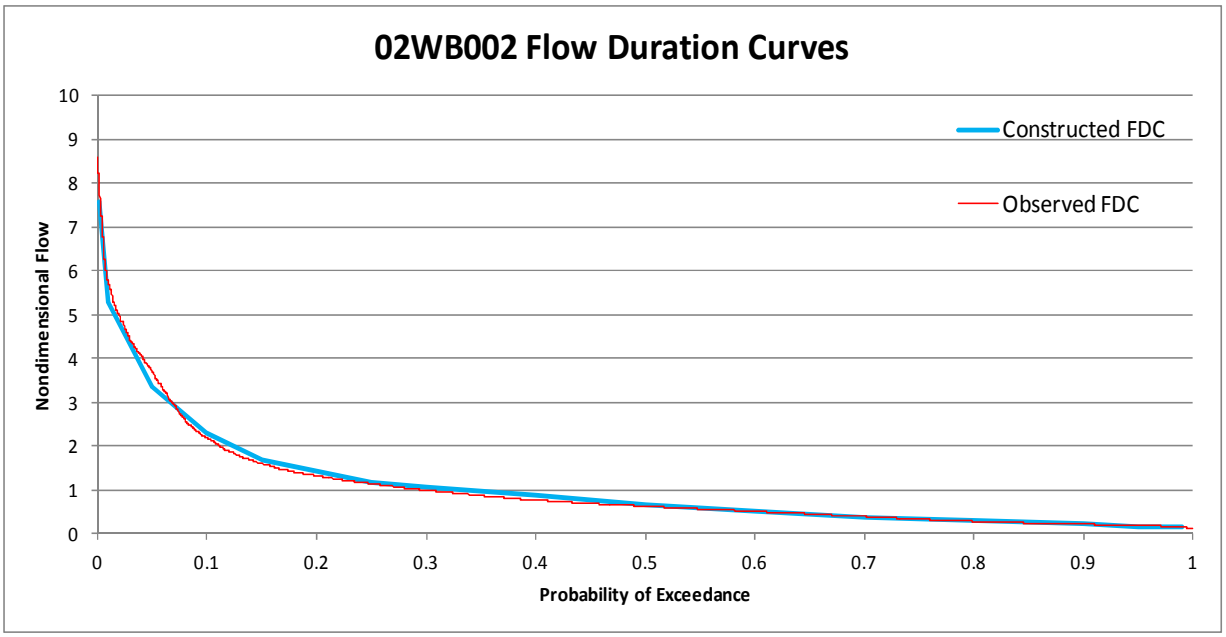

02VC002 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
1
2
3
4
5
6
7
8
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

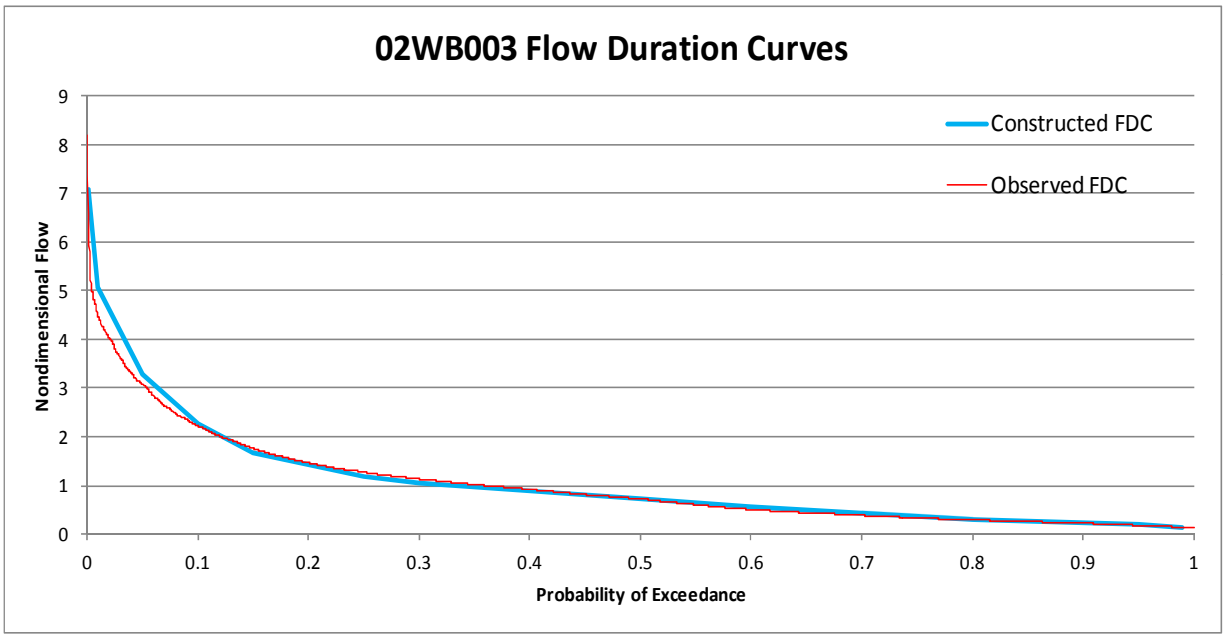

02WA001 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
1
2
3
4
5
6
7
8
9
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

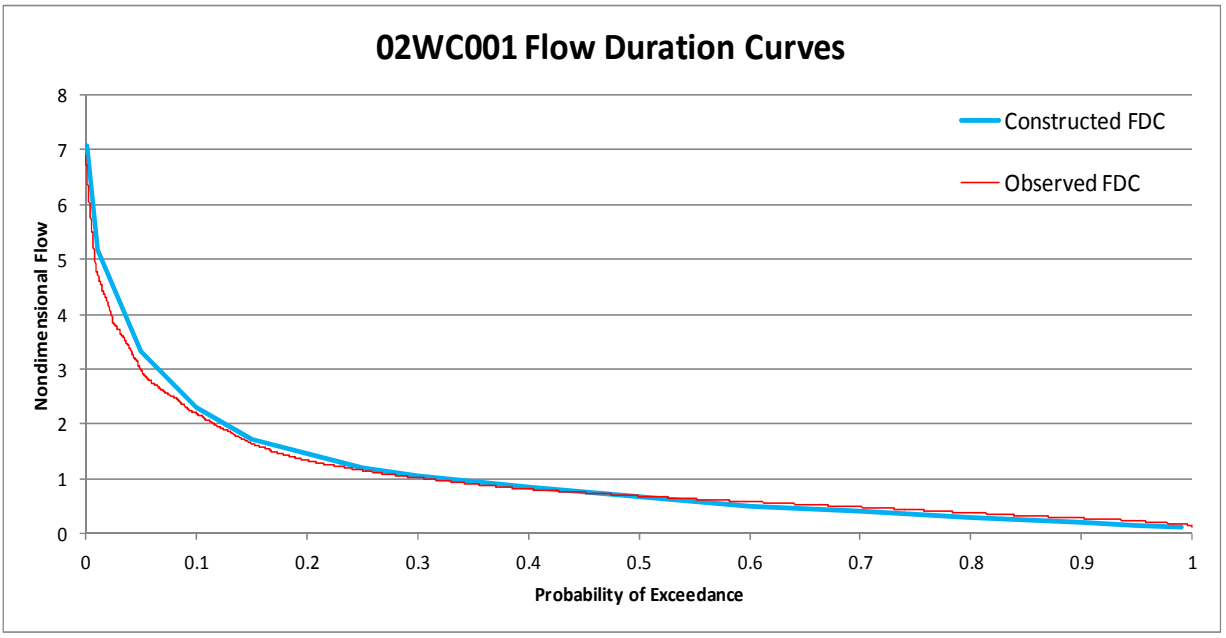

02WA002 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
1
2
3
4
5
6
7
8
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

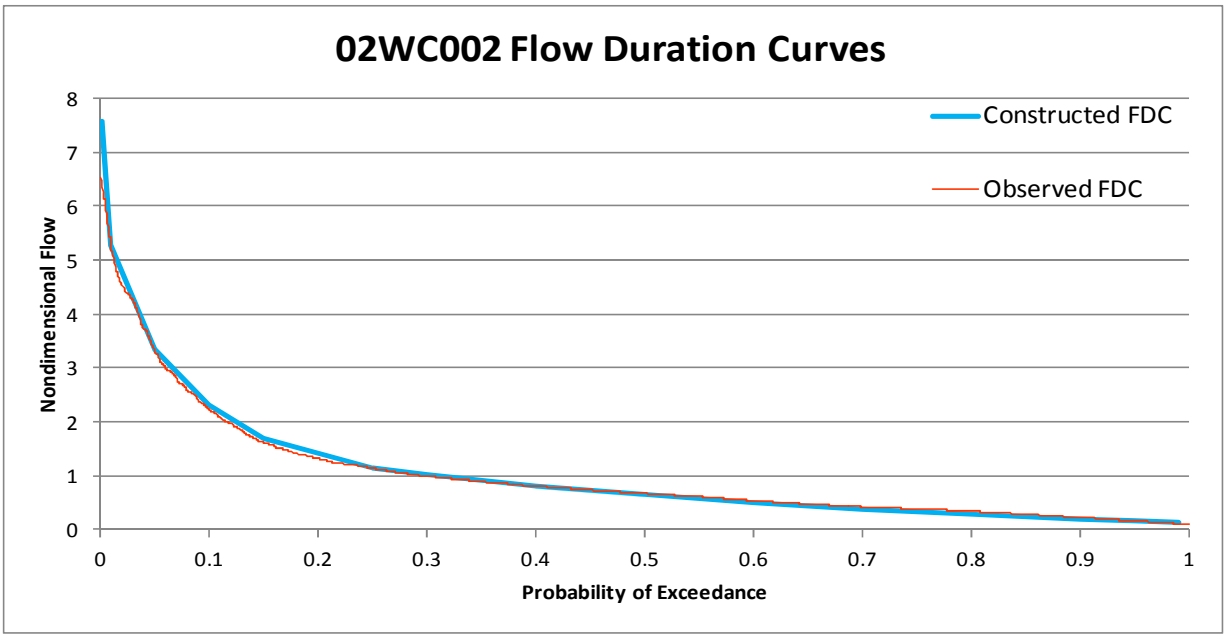

02WA003 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
2
4
6
8
10
12
14
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

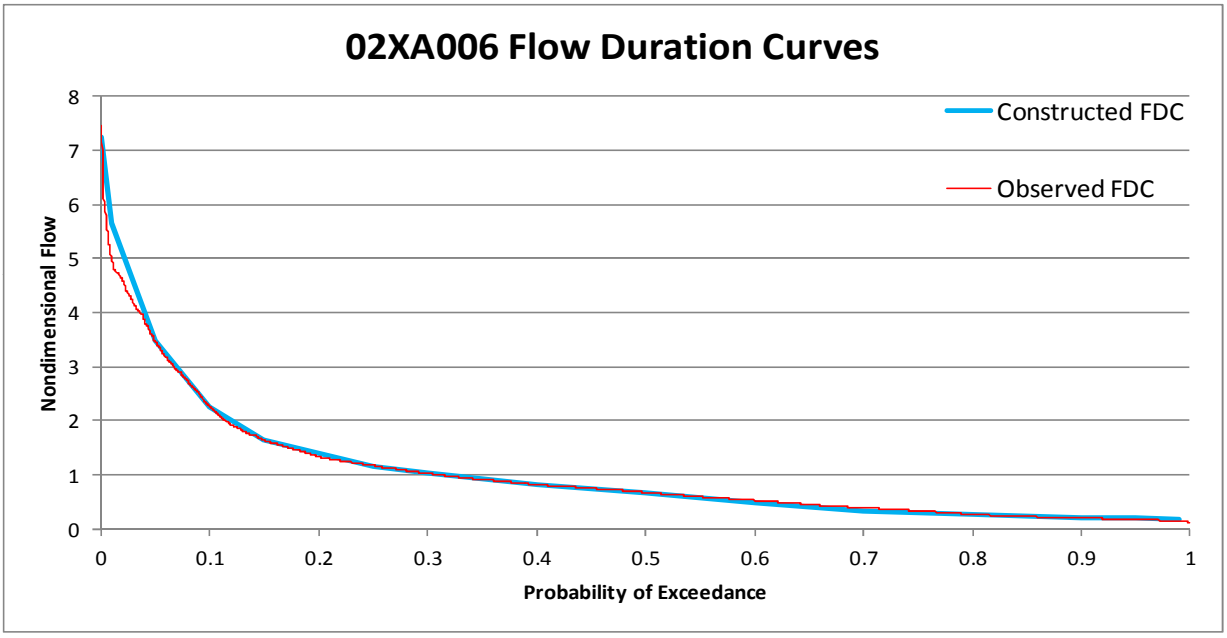

02WB001 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
1
2
3
4
5
6
7
8
9
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

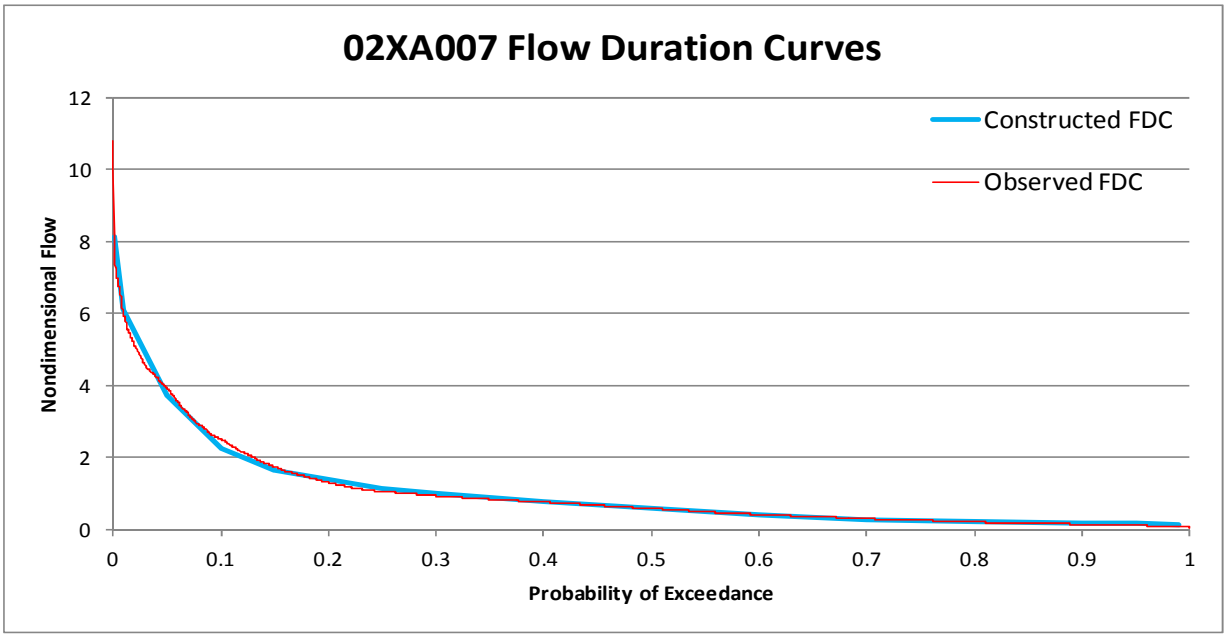

02WB002 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
1
2
3
4
5
6
7
8
9
10
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

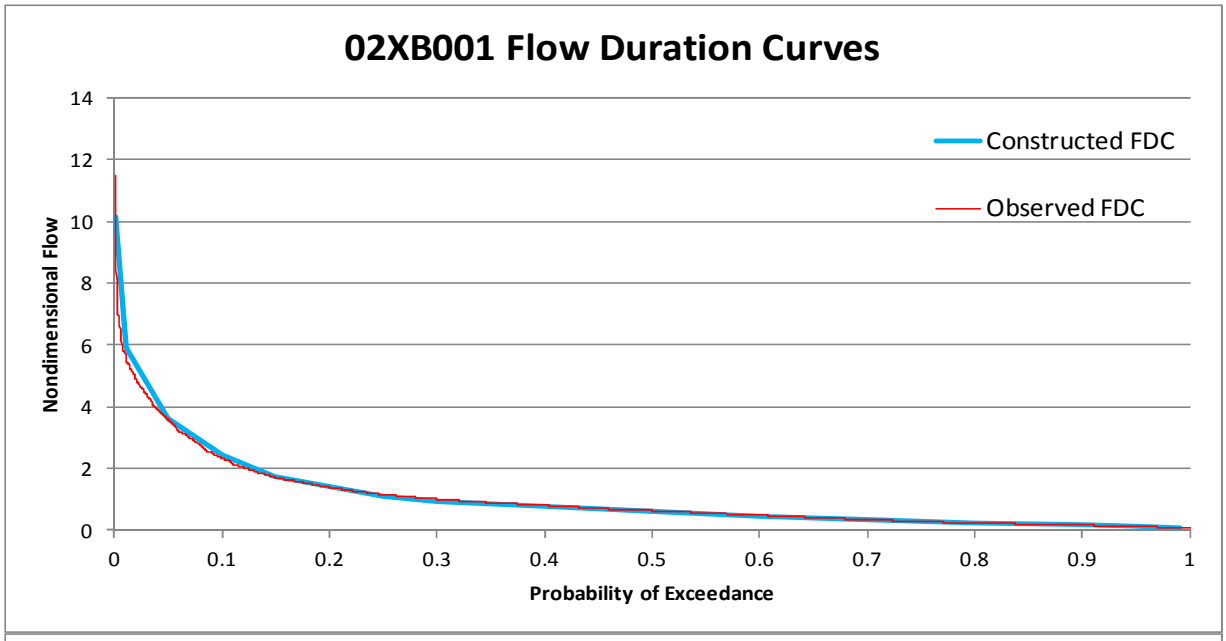

02WB003 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
1
2
3
4
5
6
7
8
9
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

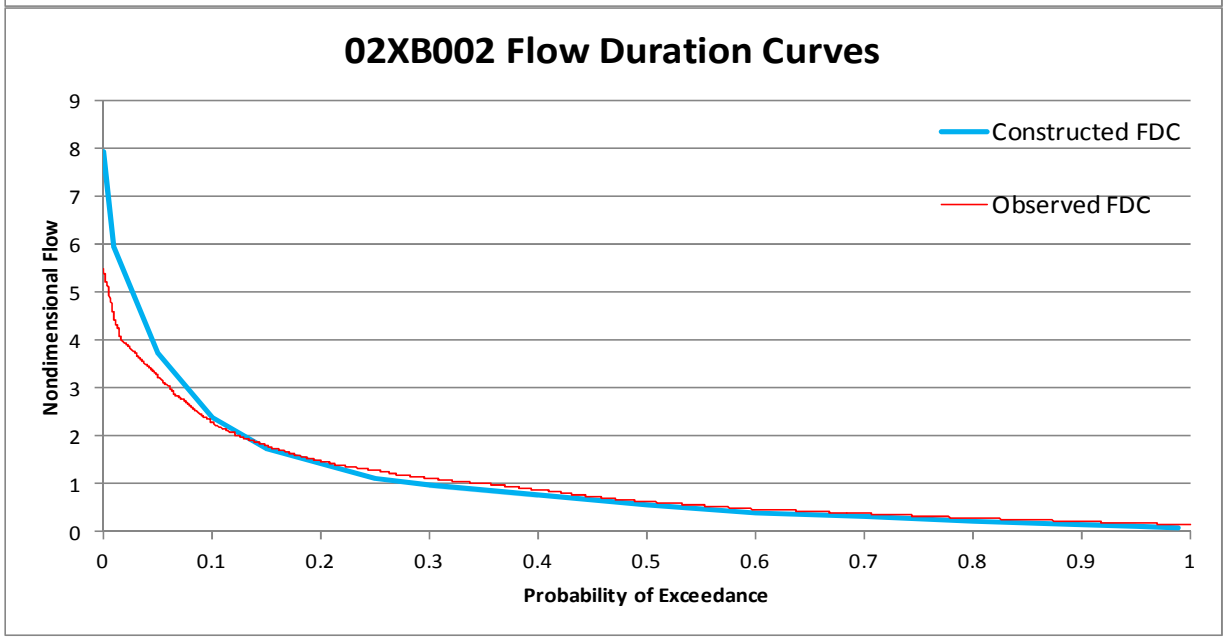

02WC001 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
1
2
3
4
5
6
7
8
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

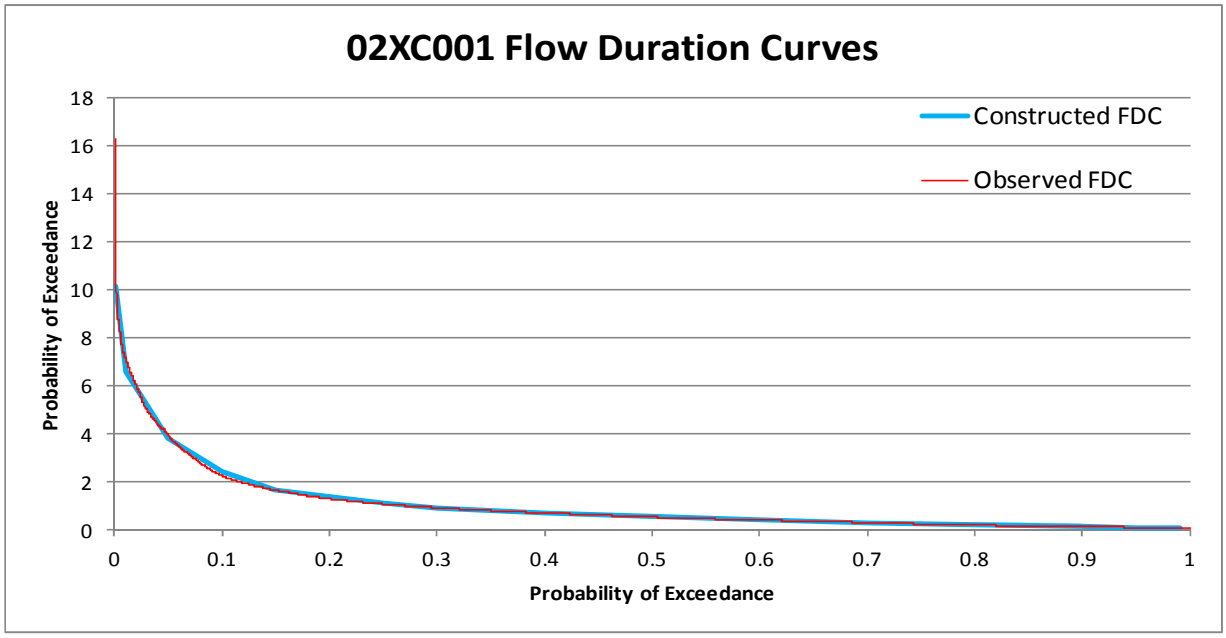

02WC002 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
1
2
3
4
5
6
7
8
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

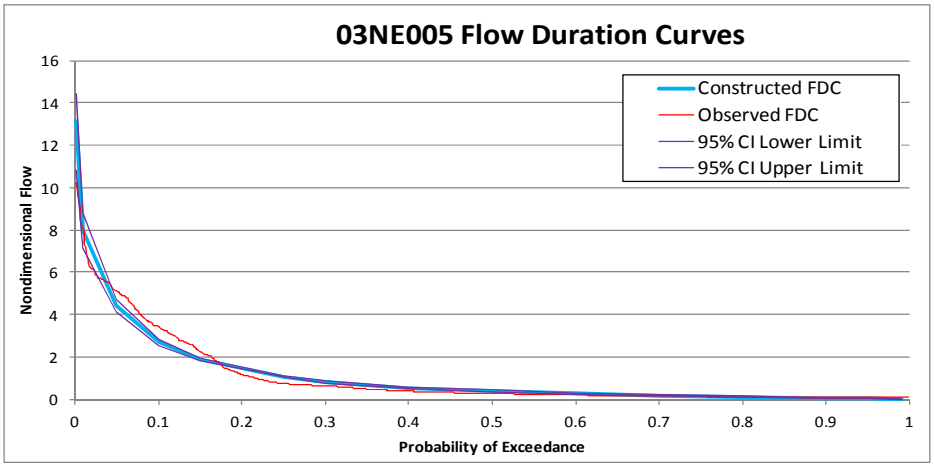

02XA006 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
1
2
3
4
5
6
7
8
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

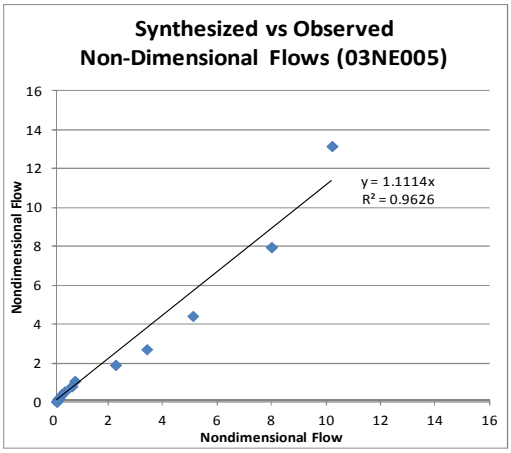

02XA007 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
2
4
6
8
10
12
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

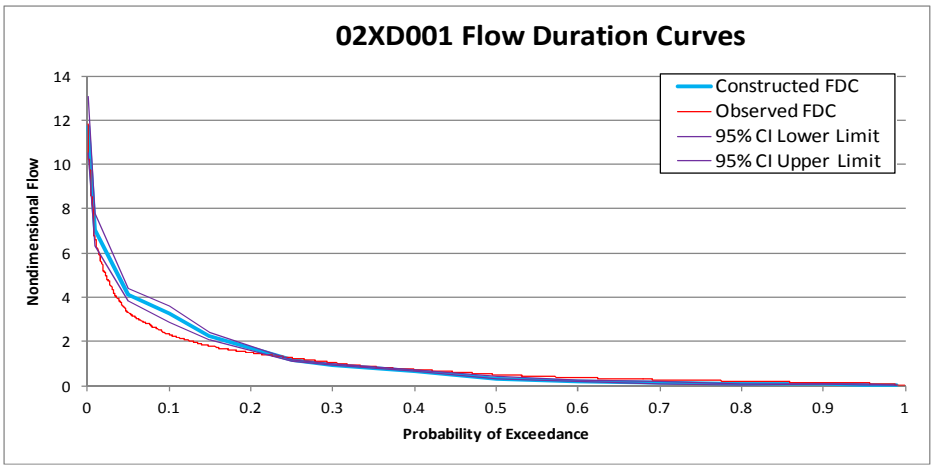

02XB001 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
2
4
6
8
10
12
14
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

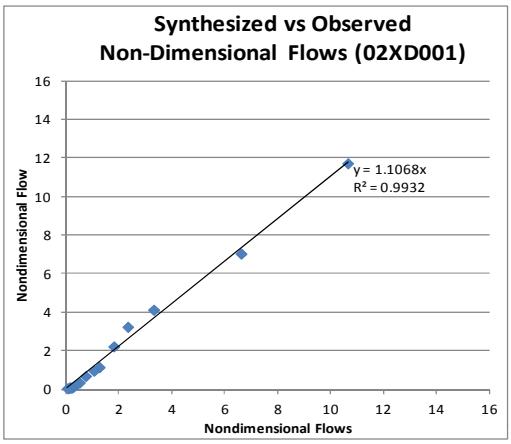

02XB002 Flow Duration Curves
Constructed FDC
Observed FDC
Nondimensional Flow
Probability of Exceedance
0
1
2
3
4
5
6
7
8
9
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

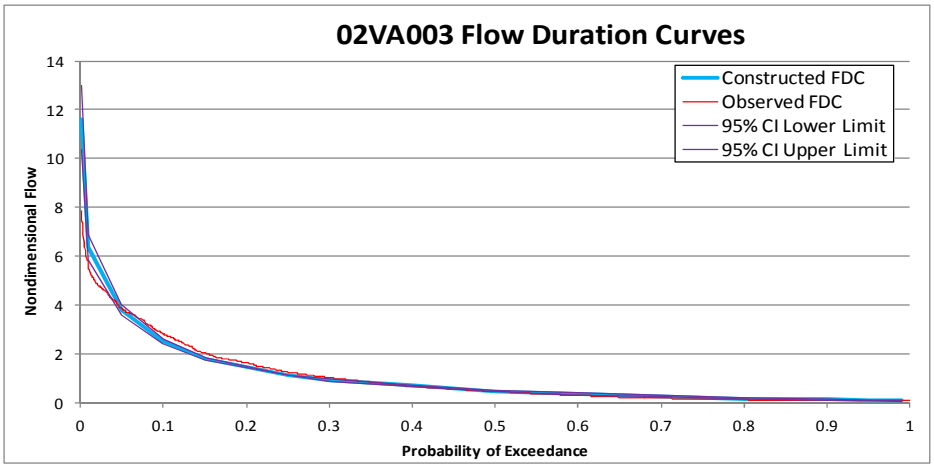

02XC001 Flow Duration Curves
Constructed FDC
Observed FDC
Probability of Exceedance
Probability of Exceedance
0
2
4
6
8
10
12
14
16
18
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

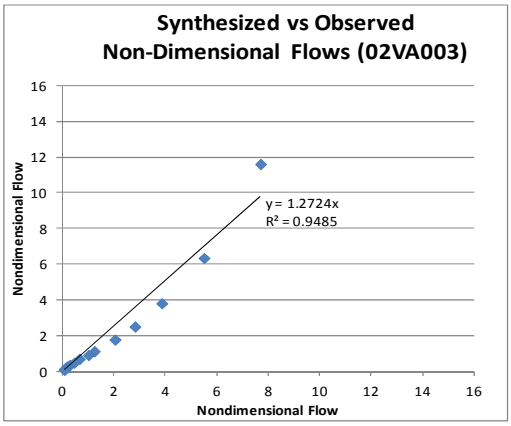

03NE005 Flow Duration Curves
Constructed FDC
Observed FDC
95% CI Lower Limit
95% CI Upper Limit
Nondimensional Flow
Probability of Exceedance


Synthesized vs Observed
Non-Dimensional Flows (03NE005)
y = 1.1114x
R² = 0.9626
Nondimensional Flow
Nondimensional Flow


02XD001 Flow Duration Curves
Constructed FDC
Observed FDC
95% CI Lower Limit
95% CI Upper Limit
Nondimensional Flow
Probability of Exceedance


Synthesized vs Observed
Non-Dimensional Flows (02XD001)
y = 1.1068x
R² = 0.9932
Nondimensional Flow
Nondimensional Flows


02VA003 Flow Duration Curves
Constructed FDC
Observed FDC
95% CI Lower Limit
95% CI Upper Limit
Nondimensional Flow
Probability of Exceedance


Synthesized vs Observed
Non-Dimensional Flows (02VA003)
y = 1.2724x
R² = 0.9485
Nondimensional Flow
Nondimensional Flow

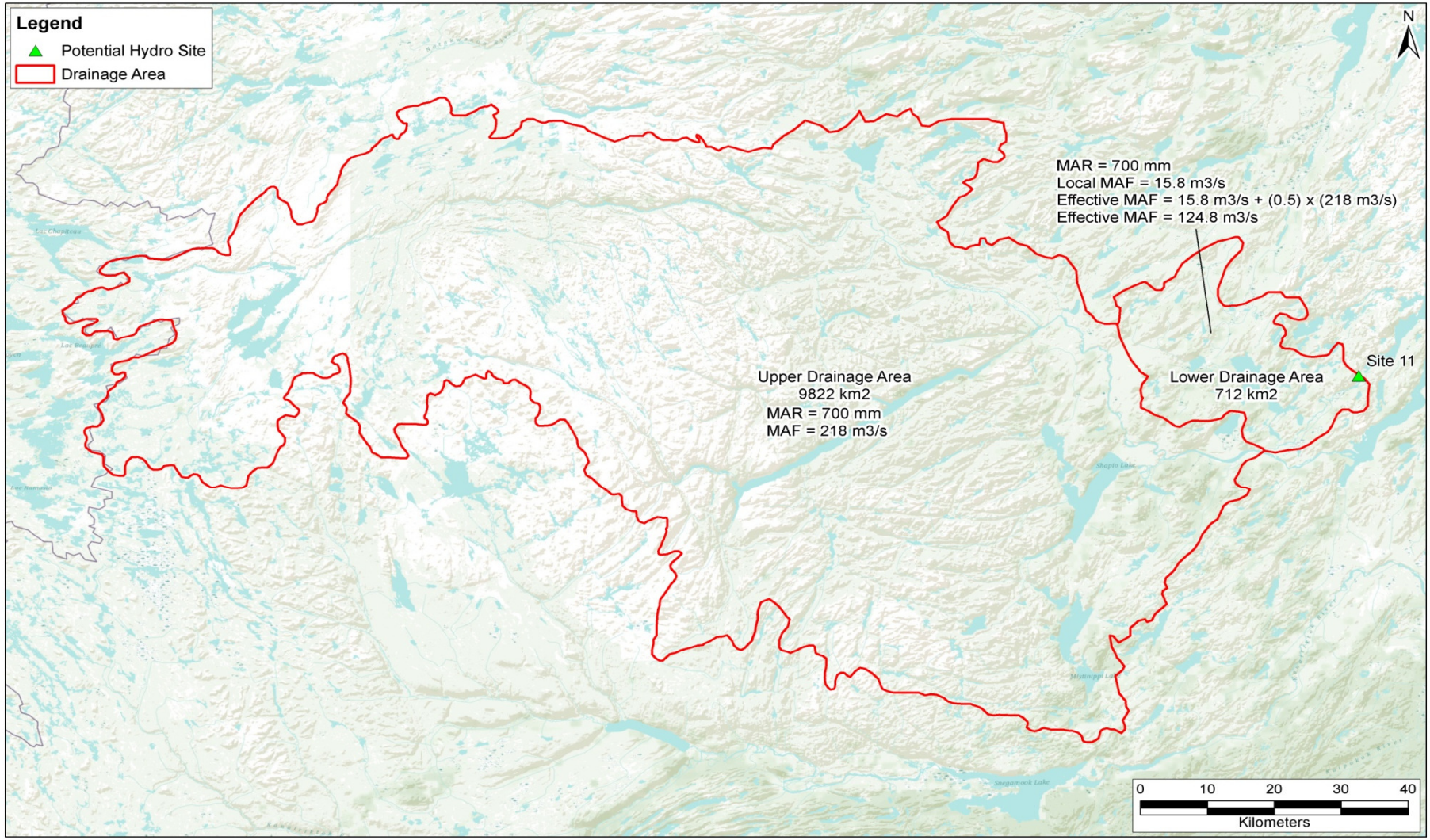
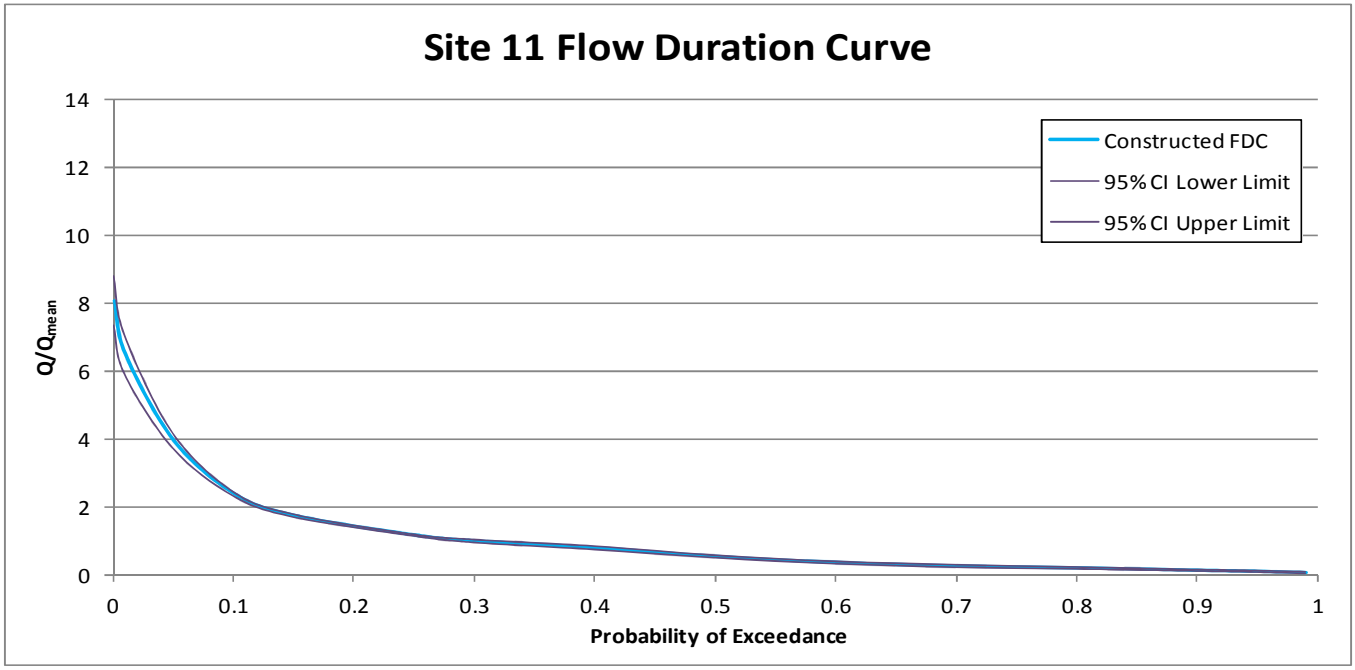
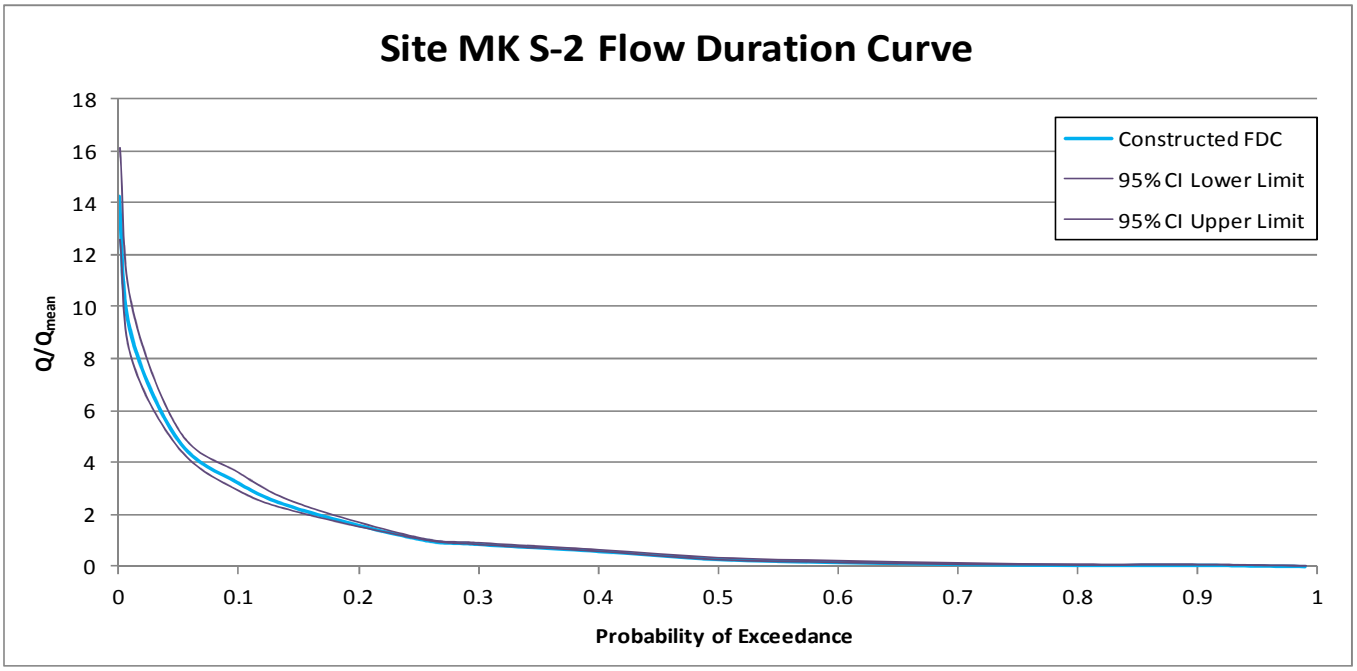
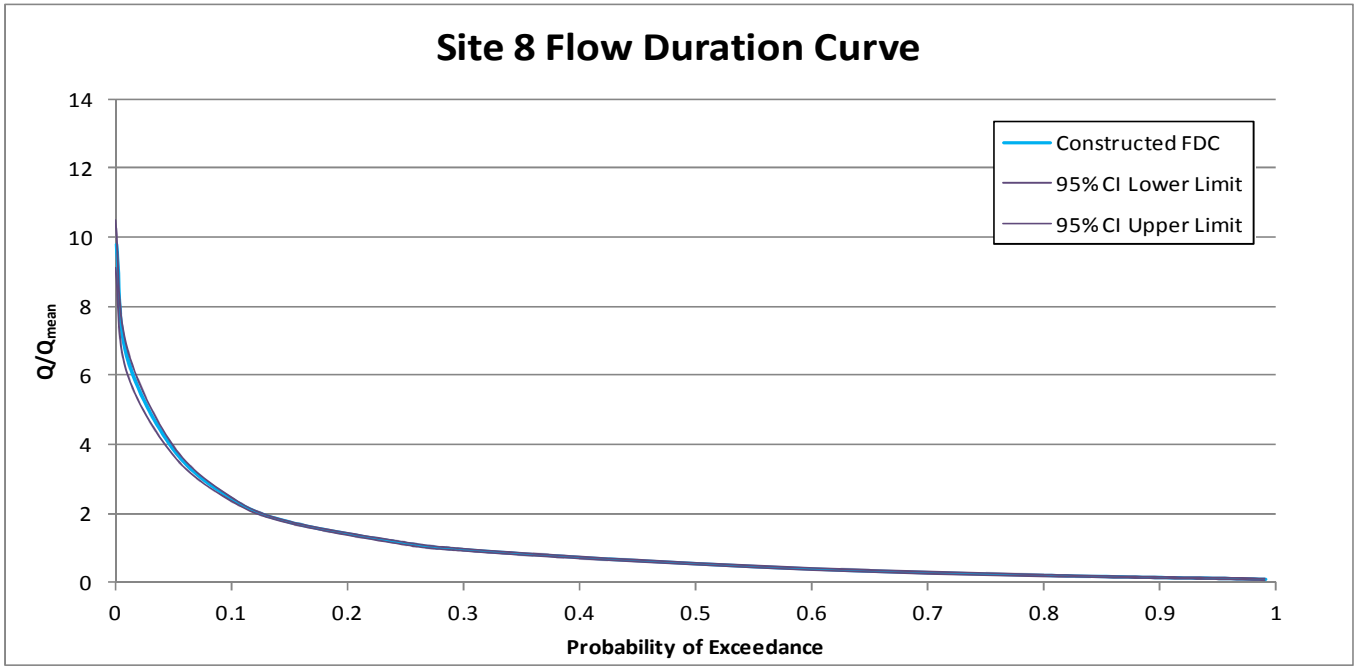
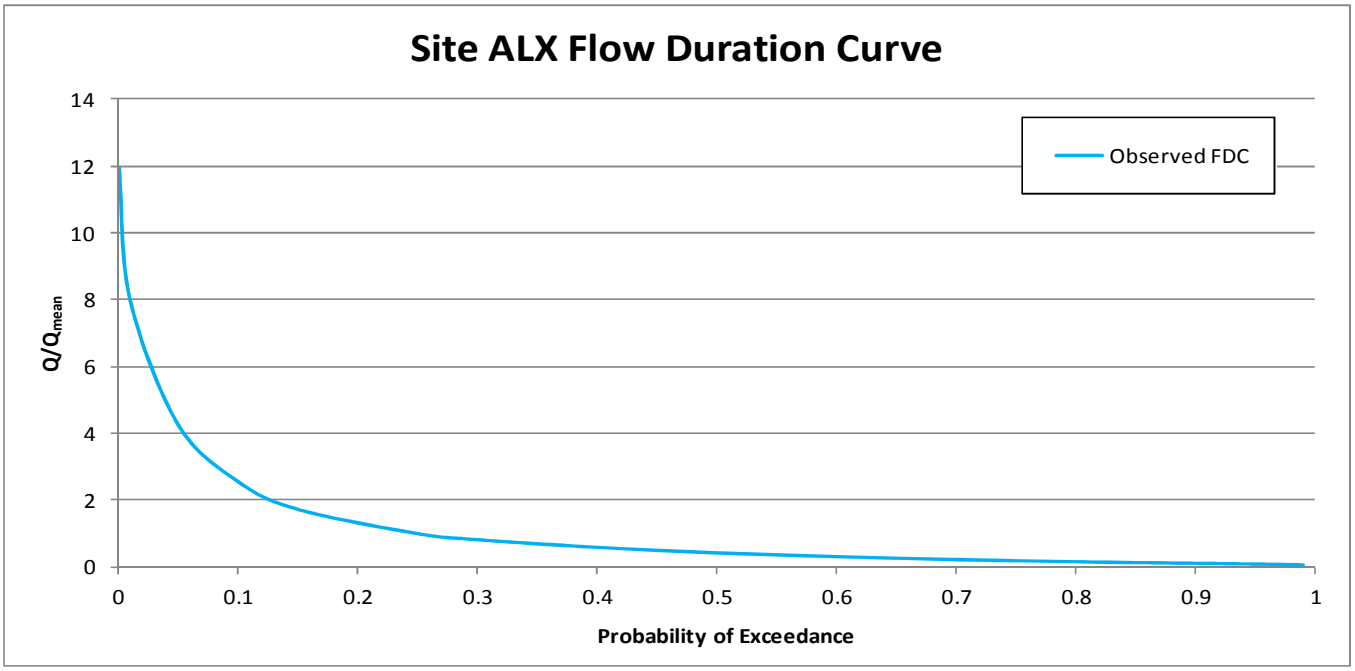


Figure C-7
Site 11 Drainage Area
Coastal Labrador Small Hydro Feasibility Study
Newfoundland Labrador Hydro


Site 11 Flow Duration Curve
Constructed FDC
95% CI Lower Limit
95% CI Upper Limit
Q/Qmean
Probability of Exceedance
0
2
4
6
8
10
12
14
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1


Site MK S-2 Flow Duration Curve
Constructed FDC
95% CI Lower Limit
95% CI Upper Limit
Q/Qmean
Probability of Exceedance
0
2
4
6
8
10
12
14
16
18
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1


Site 8 Flow Duration Curve
Constructed FDC
95% CI Lower Limit
95% CI Upper Limit
Q/Qmean
Probability of Exceedance
0
2
4
6
8
10
12
14
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1


Site ALX Flow Duration Curve
Observed FDC
Q/Qmean
Probability of Exceedance
0
2
4
6
8
10
12
14
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1

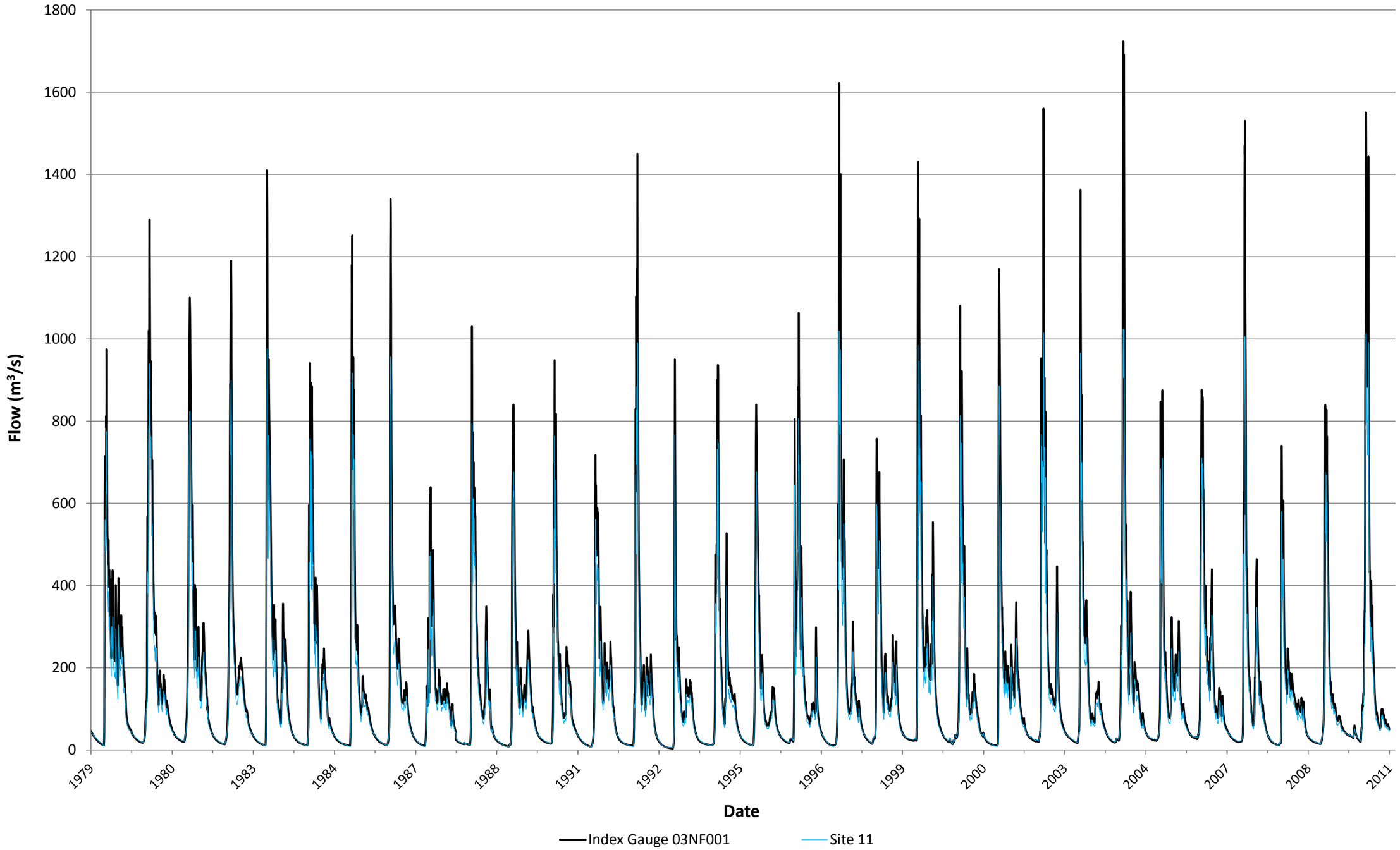
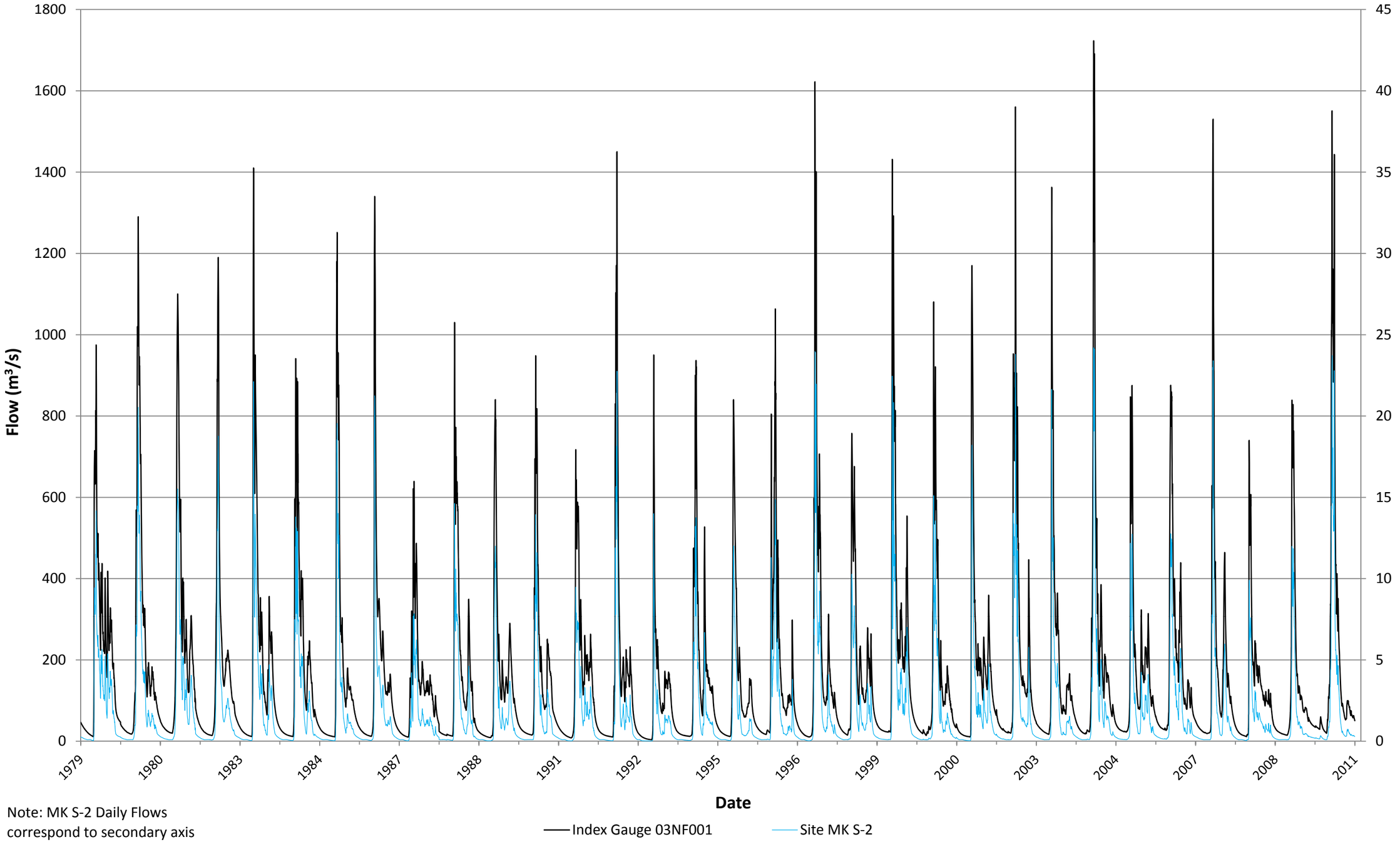
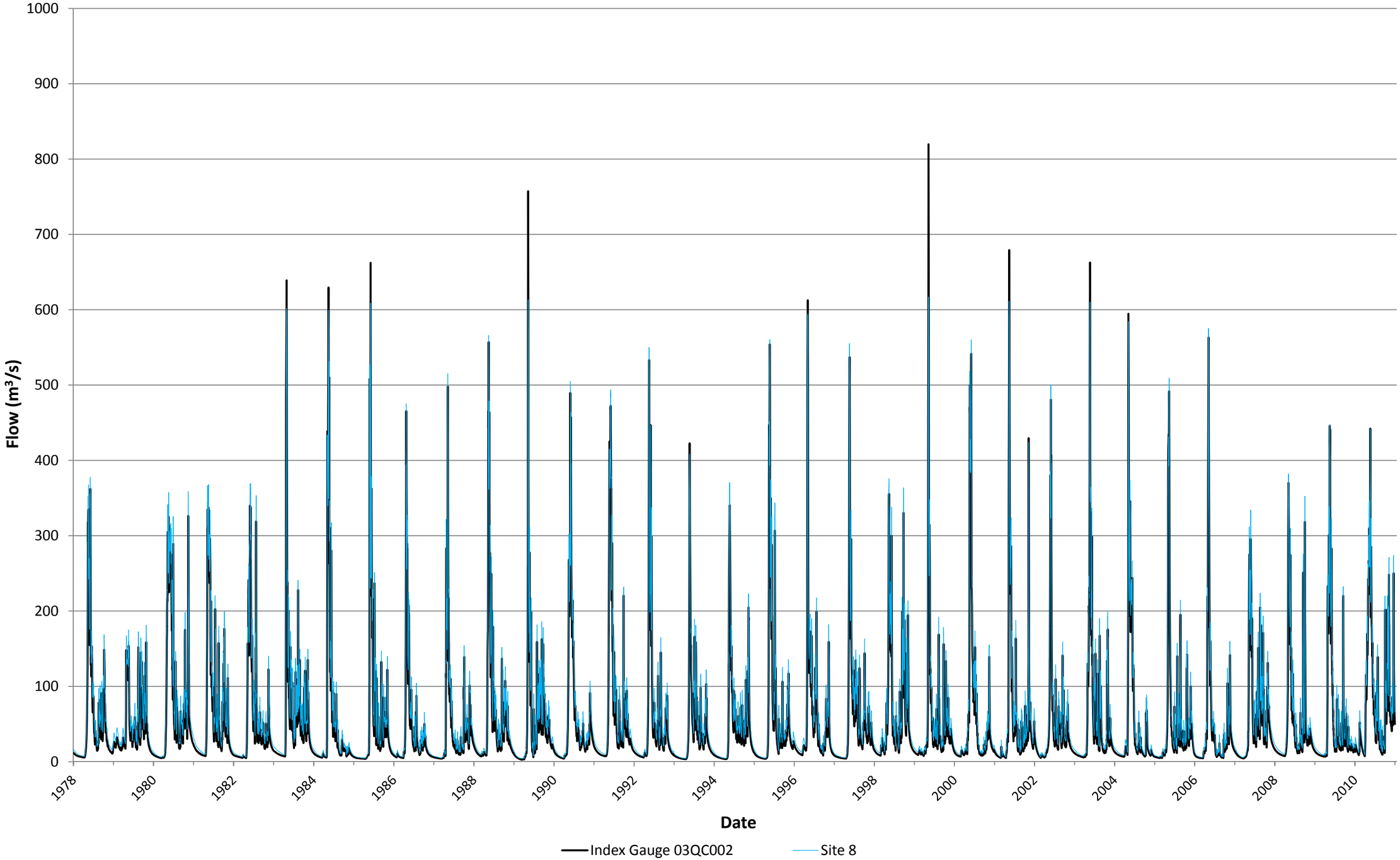


Figure C-9a
Synthesized Daily Inflow Sequence Chart - Site 11
Coastal Labrador Small Hydro Feasibility Study
Newfoundland Labrador Hydro



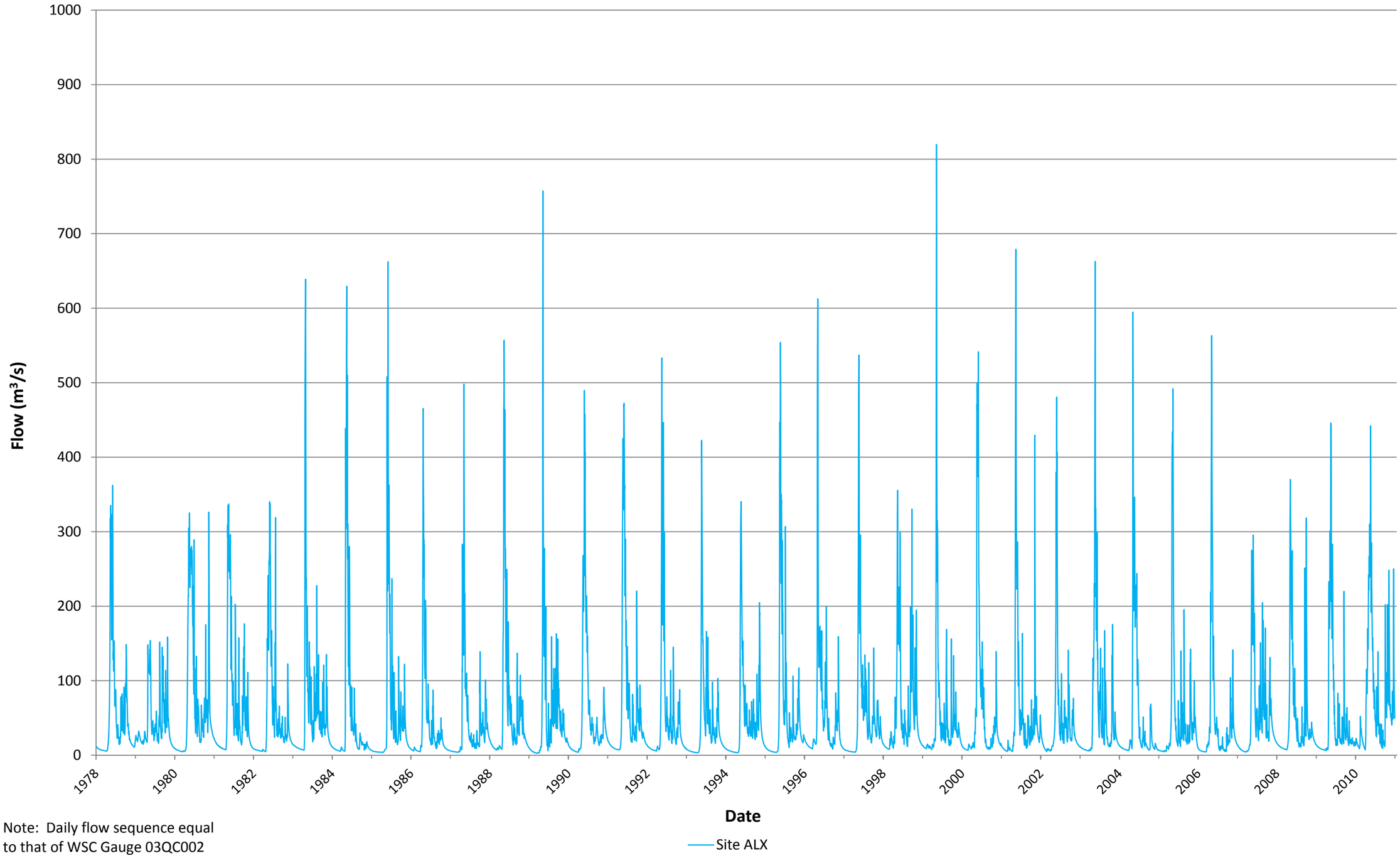
Note: MK S-2 Daily Flows correspond to secondary axis

Figure C-9b
Synthesized Daily Inflow Sequence Chart - Site MK S-2
Coastal Labrador Small Hydro Feasibility Study
Newfoundland Labrador Hydro



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Figure C-9c
Synthesized Daily Inflow Sequence Chart - Site 8
Coastal Labrador Small Hydro Feasibility Study
Newfoundland Labrador Hydro



Note: Daily flow sequence equal to that of WSC Gauge 03QC002

HATCH™

Figure C-9d
Synthesized Daily Inflow Sequence Chart - Site ALX
Coastal Labrador Small Hydro Feasibility Study
Newfoundland Labrador Hydro

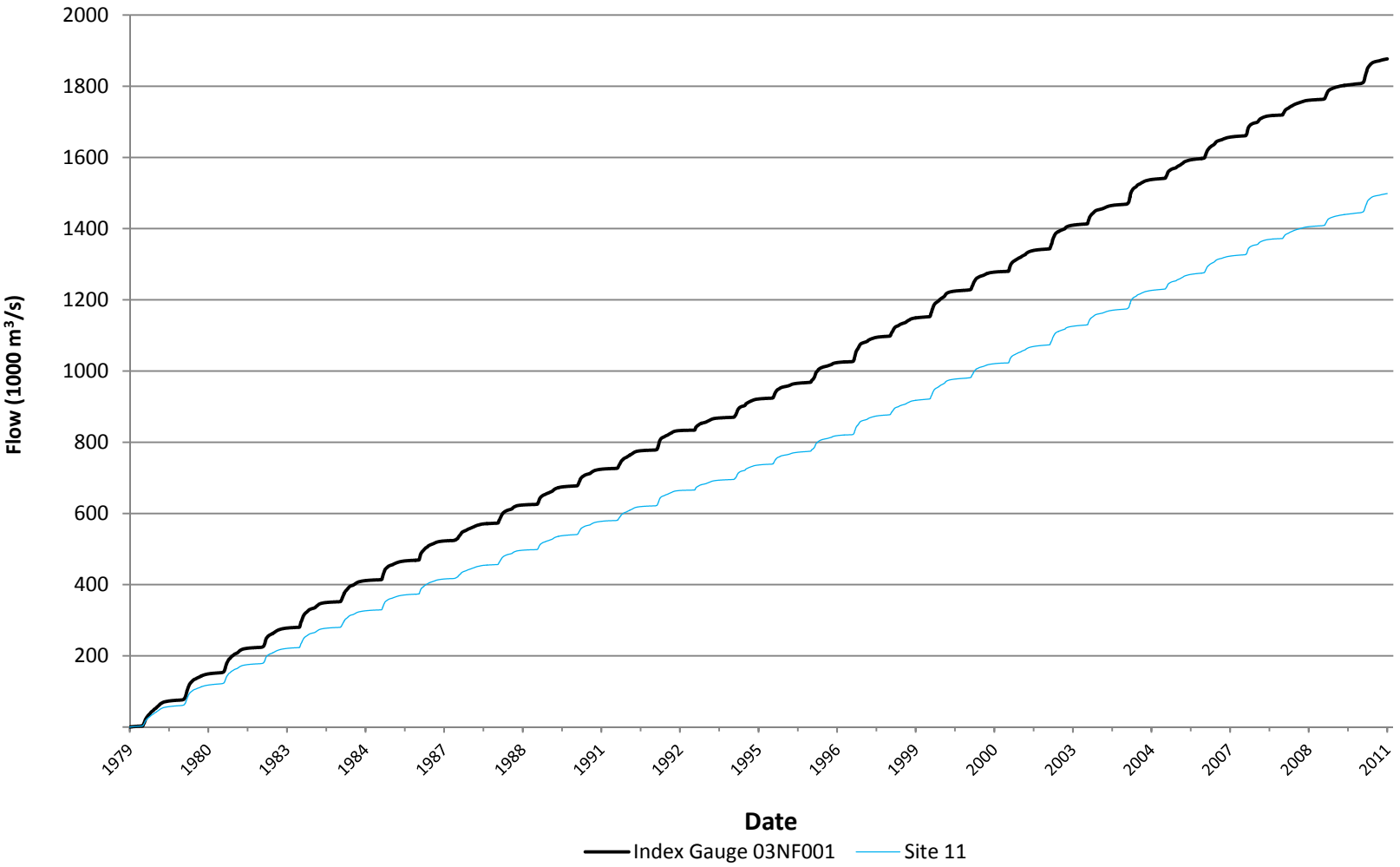
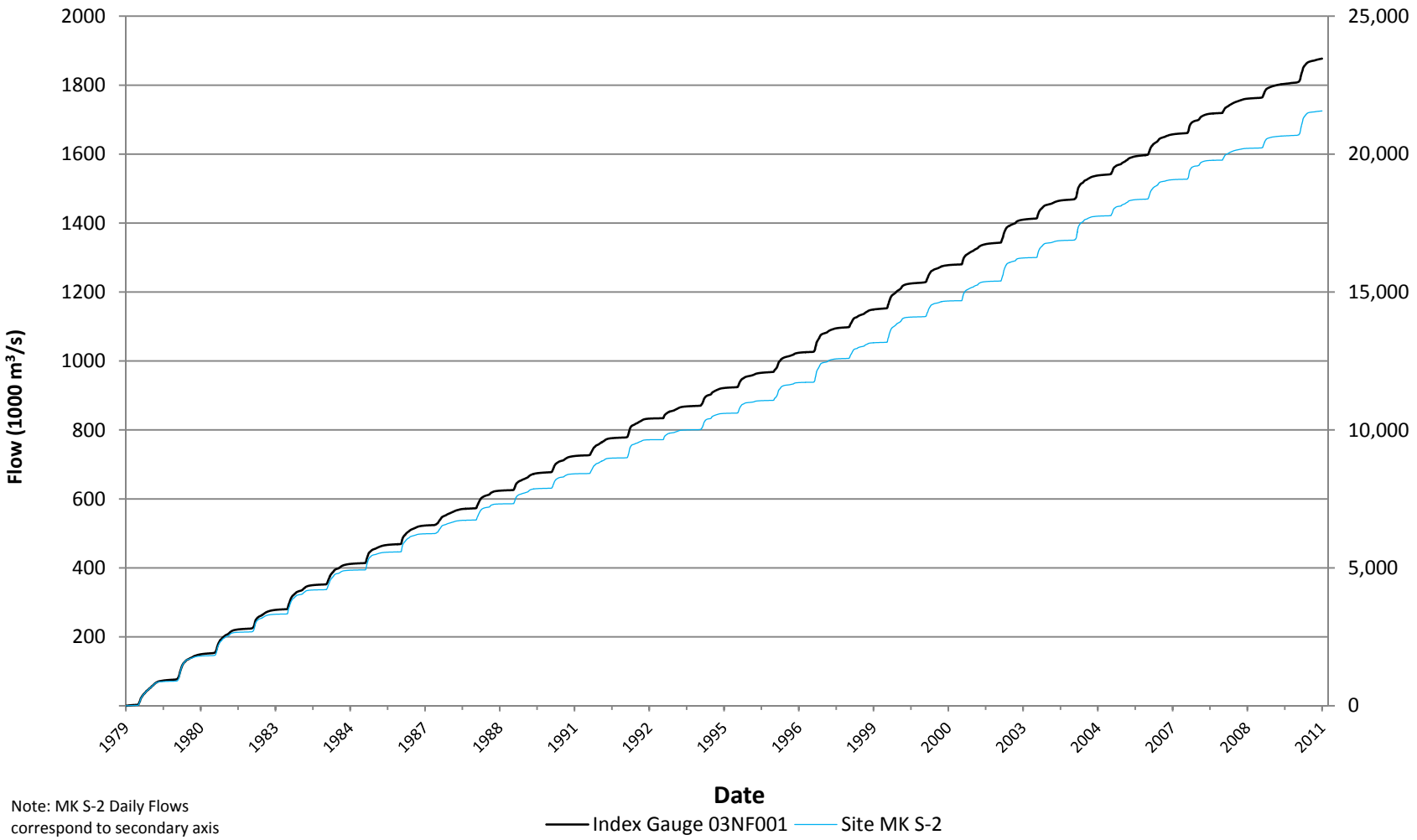


Figure C-10a
Mass Plot of Daily Inflow Sequence - Site 11
Coastal Labrador Small Hydro Feasibility Study
Newfoundland Labrador Hydro



Note: MK S-2 Daily Flows correspond to secondary axis

Figure C-10b

Mass Plot of Daily Inflow Sequence - Site MK S-2

Coastal Labrador Small Hydro Feasibility Study

Newfoundland Labrador Hydro

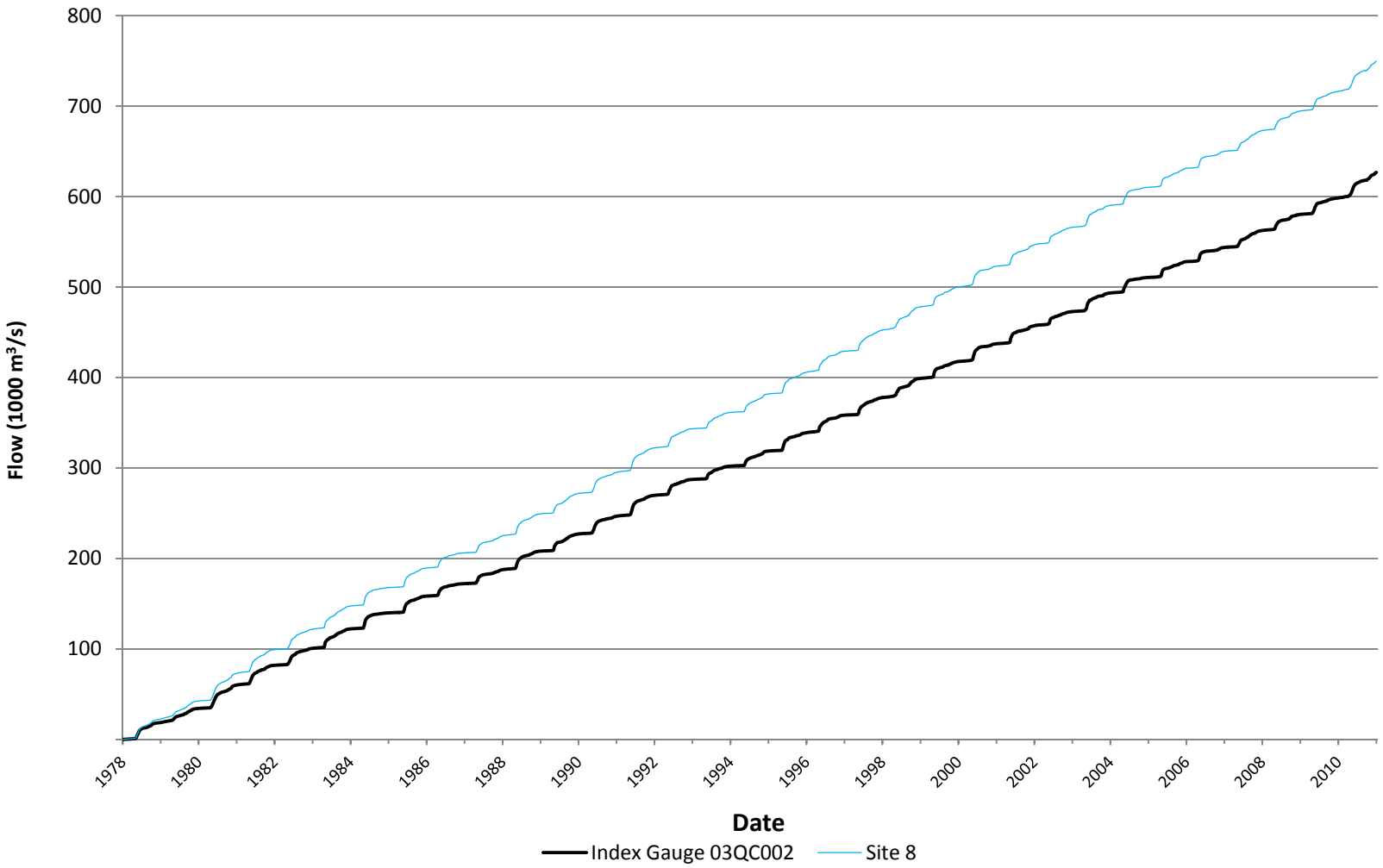
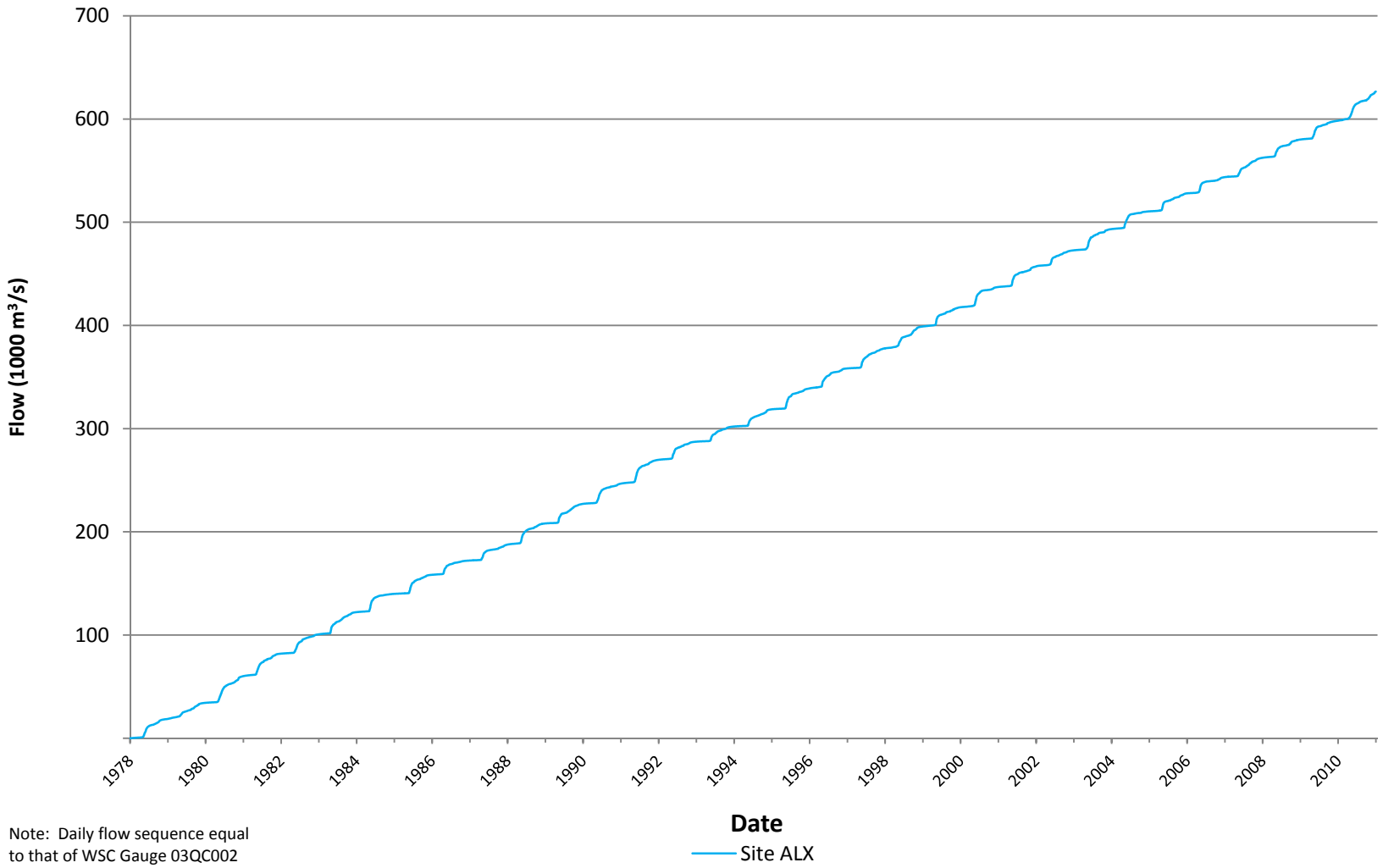


Figure C-10c

Mass Plot of Daily Inflow Sequence - Site 8

Coastal Labrador Small Hydro Feasibility Study

Newfoundland Labrador Hydro



Note: Daily flow sequence equal to that of WSC Gauge 03QC002

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Figure C-10d

Mass Plot of Daily Inflow Sequence - Site ALX

Coastal Labrador Small Hydro Feasibility Study

Newfoundland Labrador Hydro

Table C-11a
Monthly Flow Sequence Site 11

Year	Average Monthly Flow (m^3/s)												Average Annual Flow (m^3/s)
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
1979	38	29	20	14	511	297	239	193	222	181	83	47	156
1980	36	28	22	23	199	764	350	177	122	121	90	56	166
1981	40	31	26	25	167	655	291	197	130	189	88	45	157
1982	32	24	18	17	111	608	193	131	161	100	62	41	125
1983	30	21	15	50	699	309	201	90	135	182	76	42	154
1984	29	20	15	12	295	482	261	124	143	124	58	41	134
1985	29	21	16	12	35	700	236	106	112	98	64	41	122
1986	30	21	15	14	458	288	196	147	104	102	51	33	121
1987	22	14	10	119	285	233	115	115	109	109	71	54	105
1988	23	17	16	14	263	443	172	89	125	143	57	32	116
1989	21	15	9	9	270	338	124	111	116	179	91	51	111
1990	34	27	21	17	119	480	176	85	124	138	62	42	110
1991	31	21	12	8	38	411	261	132	153	157	93	41	113
1992	26	18	13	10	45	683	200	125	137	135	69	31	124
1993	16	8	7	7	224	197	103	70	119	115	51	31	79
1994	20	16	13	12	137	490	160	111	191	116	91	45	117
1995	30	22	15	12	303	319	139	66	57	96	73	40	98
1996	30	23	21	34	299	487	222	90	63	87	120	53	127
1997	34	23	14	9	51	719	401	154	83	158	94	71	151
1998	40	29	20	26	341	326	121	117	92	160	117	50	120
1999	36	30	27	26	402	538	182	201	194	208	71	43	163
2000	32	24	21	29	94	551	248	117	91	112	61	39	118
2001	29	19	13	10	444	277	152	124	152	175	120	65	132
2002	45	33	28	24	34	712	422	137	109	168	101	51	155
2003	38	31	25	20	370	363	213	81	64	108	95	56	122
2004	38	28	21	27	125	761	253	204	133	125	69	54	153
2005	36	30	27	31	391	240	93	134	141	180	98	69	122
2006	44	35	32	38	497	300	162	236	98	91	88	54	140
2007	40	31	25	22	80	615	171	68	211	153	88	49	129
2008	31	20	14	15	358	153	147	124	90	87	79	42	97
2009	29	23	19	17	82	521	162	99	68	60	45	38	97
2010	35	39	33	31	218	830	310	153	66	62	66	52	158
Mean:	32	24	19	23	248	472	209	128	122	132	79	47	128
Max:	45	39	33	119	699	830	422	236	222	208	120	71	166
Min:	16	8	7	7	34	153	93	66	57	60	45	31	79

Table C-11b
Monthly Flow Sequence Site MK S-2

Year	Average Monthly Flow (m^3/s)												Average Annual Flow (m^3/s)
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
1979	0.2	0.1	0.1	0.1	8.7	5.1	4.0	3.0	3.7	2.7	0.8	0.3	2.4
1980	0.2	0.1	0.1	0.1	3.0	14.3	5.9	2.7	1.4	1.4	0.8	0.4	2.5
1981	0.2	0.1	0.1	0.1	2.4	11.7	4.9	3.1	1.6	2.9	0.8	0.3	2.4
1982	0.2	0.1	0.1	0.1	1.5	11.2	3.0	1.6	2.2	1.0	0.5	0.2	1.8
1983	0.1	0.1	0.1	0.6	13.0	5.2	3.2	0.8	1.8	2.7	0.6	0.2	2.4
1984	0.1	0.1	0.1	0.1	4.9	8.2	4.5	1.5	1.9	1.4	0.4	0.2	2.0
1985	0.1	0.1	0.1	0.1	0.4	12.9	3.9	1.1	1.2	1.0	0.5	0.2	1.8
1986	0.1	0.1	0.1	0.1	8.8	4.9	3.1	1.9	1.1	1.1	0.3	0.2	1.8
1987	0.1	0.1	0.0	1.5	4.7	3.8	1.3	1.3	1.2	1.2	0.6	0.4	1.3
1988	0.1	0.1	0.1	0.1	4.3	7.4	2.5	0.8	1.6	1.9	0.4	0.1	1.6
1989	0.1	0.1	0.0	0.0	4.4	5.7	1.5	1.2	1.3	2.7	0.9	0.3	1.5
1990	0.2	0.1	0.1	0.1	1.7	8.2	2.6	0.8	1.6	1.7	0.5	0.3	1.5
1991	0.1	0.1	0.1	0.0	0.3	6.8	4.3	1.6	2.0	2.1	0.9	0.2	1.6
1992	0.1	0.1	0.1	0.0	0.4	12.7	3.1	1.4	1.7	1.6	0.6	0.1	1.8
1993	0.1	0.0	0.0	0.0	3.7	3.1	1.1	0.5	1.3	1.3	0.3	0.1	1.0
1994	0.1	0.1	0.1	0.1	2.2	8.5	2.3	1.3	2.8	1.3	0.9	0.3	1.6
1995	0.1	0.1	0.1	0.1	5.0	5.4	1.7	0.5	0.4	0.9	0.6	0.2	1.3
1996	0.1	0.1	0.1	0.2	5.1	8.4	3.5	0.8	0.4	0.8	1.5	0.4	1.8
1997	0.2	0.1	0.1	0.0	0.5	14.1	6.8	2.1	0.7	2.2	0.9	0.6	2.4
1998	0.2	0.1	0.1	0.1	5.6	5.4	1.4	1.3	0.9	2.2	1.4	0.3	1.6
1999	0.2	0.1	0.1	0.1	7.5	9.6	2.7	3.2	2.9	3.2	0.6	0.3	2.5
2000	0.1	0.1	0.1	0.1	1.2	9.5	4.0	1.3	0.9	1.2	0.4	0.2	1.6
2001	0.1	0.1	0.1	0.0	8.1	4.6	2.0	1.4	2.0	2.6	1.4	0.5	1.9
2002	0.3	0.2	0.1	0.1	0.2	13.4	7.2	1.7	1.2	2.5	1.0	0.3	2.3
2003	0.2	0.1	0.1	0.1	6.7	6.2	3.5	0.7	0.4	1.1	0.9	0.4	1.7
2004	0.2	0.1	0.1	0.1	1.8	15.6	4.1	3.2	1.6	1.4	0.5	0.4	2.4
2005	0.2	0.1	0.1	0.1	6.5	3.8	0.9	1.8	1.8	2.7	1.0	0.5	1.6
2006	0.3	0.2	0.1	0.2	8.5	5.1	2.2	4.0	1.0	0.9	0.8	0.4	2.0
2007	0.2	0.1	0.1	0.1	1.0	12.0	2.4	0.5	3.3	2.1	0.8	0.3	1.9
2008	0.1	0.1	0.1	0.1	6.0	2.0	1.9	1.4	0.8	0.8	0.7	0.3	1.2
2009	0.1	0.1	0.1	0.1	0.9	8.9	2.3	1.0	0.5	0.4	0.3	0.2	1.2
2010	0.2	0.2	0.2	0.2	3.4	16.4	5.3	2.1	0.5	0.5	0.5	0.3	2.5
Mean:	0.2	0.1	0.1	0.2	4.1	8.4	3.2	1.6	1.5	1.7	0.7	0.3	1.8
Max:	0.3	0.2	0.2	1.5	13.0	16.4	7.2	4.0	3.7	3.2	1.5	0.6	2.5
Min:	0.1	0.0	0.0	0.0	0.2	2.0	0.9	0.5	0.4	0.4	0.3	0.1	1.0

Table C-11c
Monthly Flow Sequence Site 8c

Year	Average Monthly Flow (m^3/s)												Average Annual Flow (m^3/s)
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
1978	13	10	8	15	210	181	55	45	64	92	28	18	62
1979	33	34	28	49	125	45	47	64	91	83	40	17	55
1980	10	7	7	34	271	232	81	51	52	90	121	43	83
1981	25	17	13	18	281	150	80	64	47	92	54	17	71
1982	10	8	7	8	192	186	107	54	45	35	58	28	62
1983	18	14	11	145	169	94	61	108	56	70	69	22	70
1984	13	9	9	9	341	119	63	26	24	20	18	11	55
1985	7	6	5	5	99	267	93	42	59	58	54	16	59
1986	9	11	7	144	160	59	47	24	30	35	14	9	46
1987	7	6	6	77	206	66	27	19	25	67	59	50	51
1988	23	13	12	15	300	131	70	32	58	77	45	20	66
1989	10	5	5	13	252	65	48	86	100	69	52	28	61
1990	15	9	6	11	194	239	77	44	42	28	53	49	64
1991	23	15	11	11	222	253	93	48	61	74	48	26	74
1992	15	10	8	13	217	154	52	58	52	61	34	15	57
1993	9	6	5	5	164	94	101	47	46	65	30	16	49
1994	10	7	5	5	177	113	60	53	53	60	102	26	56
1995	12	8	6	5	250	168	100	34	48	44	74	30	65
1996	25	16	19	56	249	99	103	37	21	51	69	16	63
1997	9	7	6	7	229	140	101	59	42	66	59	37	64
1998	17	12	29	45	205	116	46	43	130	98	77	24	70
1999	15	16	14	23	278	65	45	70	46	61	52	34	60
2000	14	10	16	20	236	201	93	19	15	33	65	24	62
2001	14	8	14	17	282	109	70	24	42	49	102	41	64
2002	30	10	10	14	156	126	57	57	67	46	40	19	53
2003	14	10	8	26	281	135	79	68	30	57	56	26	66
2004	15	11	9	22	297	158	27	31	15	39	16	13	54
2005	8	7	12	37	265	39	51	70	35	66	55	36	57
2006	9	7	10	70	270	52	19	15	16	44	71	29	51
2007	15	8	6	13	194	106	63	105	83	61	66	31	62
2008	19	14	11	42	250	84	33	30	72	82	43	27	59
2009	16	12	10	50	275	107	39	40	66	42	31	23	59
2010	22	35	20	115	297	133	73	45	21	122	111	101	91
Mean:	15	11	11	34	230	130	66	49	50	62	57	28	62
Max:	33	35	29	145	341	267	107	108	130	122	121	101	91
Min:	7	5	5	5	99	39	19	15	15	20	14	9	46

Table C-11d
Monthly Flow Sequence Site ALX

Year	Average Monthly Flow (m^3/s)												Average Annual Flow (m^3/s)
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
1978	10	7	6	11	188	160	41	34	49	75	20	13	51
1979	23	24	20	38	108	32	34	51	74	67	29	12	43
1980	8	6	5	26	246	208	65	38	38	72	103	31	71
1981	18	12	9	13	252	130	64	49	35	76	41	12	59
1982	8	6	6	6	172	164	89	40	32	25	45	20	51
1983	13	10	8	142	152	77	47	90	41	55	54	16	59
1984	9	7	7	7	327	101	48	19	17	14	13	8	48
1985	5	5	4	4	90	248	77	31	46	44	41	11	51
1986	7	8	5	132	141	45	36	17	21	25	10	7	38
1987	5	5	5	67	188	51	19	13	17	52	45	36	42
1988	16	9	9	11	282	113	53	23	45	60	33	15	56
1989	7	4	3	10	242	53	37	68	83	53	38	20	52
1990	11	7	5	8	175	220	60	32	30	19	39	36	53
1991	16	11	8	8	208	235	75	36	48	58	35	19	63
1992	11	8	6	9	200	135	38	45	41	46	24	11	48
1993	7	5	4	4	149	77	83	35	33	50	21	11	40
1994	7	5	4	4	159	95	45	39	39	46	85	18	45
1995	9	6	5	4	237	148	83	25	36	31	58	21	55
1996	17	11	13	47	232	81	84	27	15	38	55	12	53
1997	7	5	5	5	212	120	83	45	30	51	44	27	53
1998	12	9	20	33	184	98	34	32	113	80	62	17	58
1999	11	12	10	16	274	51	32	56	36	47	38	24	51
2000	10	7	11	14	224	183	76	14	11	24	50	17	53
2001	10	6	10	12	269	92	54	17	30	36	86	29	54
2002	21	7	7	10	139	110	43	43	53	34	28	14	42
2003	10	7	6	20	265	117	63	53	22	47	42	18	56
2004	11	8	7	16	276	141	19	22	11	29	11	9	47
2005	6	5	9	28	252	28	39	55	25	53	41	26	47
2006	7	5	7	58	251	38	14	11	12	34	56	21	43
2007	11	6	5	9	173	88	48	87	66	47	50	22	51
2008	14	10	8	32	226	67	24	21	59	67	31	19	48
2009	12	9	7	44	255	90	29	29	53	31	22	16	50
2010	16	25	14	98	273	113	57	32	15	104	92	83	77
Mean:	11	8	8	29	213	112	51	37	39	48	44	20	52
Max:	23	25	20	142	327	248	89	90	113	104	103	83	77
Min:	5	4	3	4	90	28	14	11	11	14	10	7	38

Gauge Number	Gauge Name	Drainage Area (km^2)	Period of Record	Number of Annual Maximum Daily Flows in Record	Number of Annual Maximum Instantaneous Flows in Record
02XA003	LITTLE MECATINA RIVER ABOVE LAC FOURMONT	4478.0	1978 - 2010	30	27
02XA004	RIVIERE JOIR NEAR PROVINCIAL BOUNDARY	2056.6	1980 - 1996	15	12
02YA002	BARTLETTS RIVER NEAR ST. ANTHONY	36.6	1986 - 2010	25	23
03NE001	REID BROOK AT OUTLET OF REID POND	75.5	1995 - 2010	12	11
03NE002	AMP POND BROOK BELOW CAMP POND	24.9	1995 - 2010	12	11
03NF001	UGJOKTOK RIVER BELOW HARP LAKE	7307.3	1979 - 2010	31	21
03NG001	KANAIRIKTOK RIVER BELOW SNEGAMOOK LAKE	8926.0	1979 - 1996	17	13
03OC003	ATIKONAK RIVER ABOVE PANCHIA LAKE	15884.5	1972 - 2010	15	12
03OD007	EAST METCHIN RIVER	1776.0	1998 - 2010	12	10
03OE003	MINIPI RIVER BELOW MINIPI LAKE	2219.0	1979 - 2010	28	25
03OE010	BIG POND BROOK BELOW BIG POND	70.7	1994 - 2010	16	17
03OE011	PINUS RIVER	800.2	1998 - 2010	12	11
03PB002	NASKAUPI RIVER BELOW NASKAUPI LAKE	4540.9	1978 - 2010	29	25
03QC001	EAGLE RIVER ABOVE FALLS	10705.0	1966 - 2010	40	35
03QC002	ALEXIS RIVER NEAR PORT HOPE SIMPSON	2312.0	1978 - 2010	33	29
02UC002	MOISIE (RIVIERE) A 5,1 KM EN AMONT DU PONT DU Q.N.	18956.7	1965-2001	32	0
02UC003	PEKANS (RIVIERE AUX)	3355.7	1965-1982	16	0
02VA001	TONNERRE (RIVIERE AU)	682.5	1947-1986	32	0
02VB003	MAGPIE (RIVIERE)	7530.7	1965-1979	13	0
02VB004	MAGPIE (RIVIERE) A LA SORTIE DU LAC MAGPIE	7139.6	1978-2001	22	0
02VC001	ROMAINE (RIVIERE) AU PONT DE LA Q.I.T.	12940.7	1956-2001	43	0
02WA001	NABISIPI (RIVIERE)	2055.6	1962-1988	25	0
02WA002	AGUANUS (RIVIERE) EN AMONT DE LA RIVIERE DANY	5597.6	1962-1982	19	0
02WB002	NATASHQUAN (RIVIERE) EN AVAL DE LA RIVIERE NATASHQ	11406.7	1966-1983	16	0
02WB003	SHQUAN (RIVIERE) A 0,6 KM EN AVAL DE LA DECHARGE D	15383.3	1980-2001	19	0
02WC001	ETAMAMIOU (RIVIERE) PRES DE L'EMBOUCHURE	2939.8	1974-1993	18	0
02XA006	PETIT MECATINA (RIVIERE DU)	19267.2	1965-1980	11	0
02XA007	PETIT MECATINA (RIVIERE DU) EN AVAL DU LAC BRETON	12108.6	1978-1993	11	0
02XB001	SAINT-AUGUSTIN (RIVIERE) EN AVAL DE LA RIVIERE A L	5725.3	1967-1982	14	0
02XB002	COXIPI (RIVIERE) A LA SORTIE DU LAC COXIPI	1024.8	1980-1993	10	0
02XC001	SAINT-PAUL (RIVIERE) A 0,5 KM DU RUISSEAU CHANION	5524.2	1967-2001	28	0

Table C-13
Gauge Flood Frequency Estimates

Coastal Labrador Hydro
Phase 2

Gauge Number	Drainage Area (km2)	5 yr Max Daily (m^3/s)	10 yr Max Daily (m^3/s)	25 yr Max Daily (m^3/s)	100 yr Max Daily (m^3/s)	1000 yr Max Daily (m^3/s)
02XA003	4478	779	870	977	1130	1360
02XA004	2057	416	471	539	635	791
02YA002	37	18	21	26	32	43
03NE001	76	23	25	28	32	38
03NE002	25	5	6	7	8	10
03NF001	7307	1370	1540	1760	2060	2540
03NG001	8926	1500	1750	2070	2550	3350
03OC003	15885	1370	1500	1650	1860	2180
03OD007	1776	212	238	268	311	378
03OE003	2219	292	330	377	442	548
03OE010	71	17	19	21	24	29
03OE011	800	145	164	188	222	276
03PB002	4541	563	625	698	801	959
03QC001	10705	2210	2510	2870	3400	4250
03QC002	2312	625	722	843	1020	1310
02UC002	18957	2710	3070	3490	4100	5080
02UC003	3356	540	599	669	766	916
02VA001	683	250	308	384	503	722
02VB003	7531	1260	1400	1560	1790	2130
02VB004	7140	1080	1240	1440	1730	2200
02VC001	12941	1950	2230	2590	3100	3930
02WA001	2056	453	507	571	662	805
02WA002	5598	1080	1180	1300	1470	1720
02WB002	11407	2150	2390	2670	3060	3680
02WB003	15383	1940	2180	2470	2880	3530
02WC001	2940	553	639	746	902	1160
02XA006	19267	3050	3390	3800	4370	5250
02XA007	12109	1990	2240	2530	2930	3580
02XB001	5725	1510	1710	1950	2300	2850
02XB002	1025	143	155	169	188	215
02XC001	5524	1580	1850	2180	2670	3490

Flood	Prediction Equation	R^2	Standard Error of Estimate
5 yr Max Daily	exp(67.1+0.857*Ln DA+0.0734*Ln AB-4.39*Ln LAT-0.465*Ln AL)	0.98	0.179970
10 yr Max Daily	exp(72.6+0.852*Ln DA+0.0783*Ln AB-4.74*Ln LAT-0.487*Ln AL)	0.98	0.187924
25 yr Max Daily	exp(78.2+0.847*Ln DA+0.0836*Ln AB-5.09*Ln LAT-0.509*Ln AL)	0.98	0.199846
100 yr Max Daily	exp(85.0+0.841*Ln DA+0.0901*Ln AB-5.52*Ln LAT-0.536*Ln AL)	0.98	0.216551
1000 yr Max Daily	exp(94.3+0.832*Ln DA+0.0988*Ln AB-6.10*Ln LAT-0.572*Ln AL)	0.98	0.244291

Gauge Number	Gauge Frequency Estimates					Regression Estimates					Percentage Difference				
	5 yr	10 yr	25 yr	100 yr	1000 yr	5 yr	10 yr	25 yr	100 yr	1000 yr	5 yr	10 yr	25 yr	100 yr	1000 yr
02XA003	779	870	977	1130	1360	1024	1075	1246	1379	1784	31.5	23.6	27.5	22.1	31.1
02XA004	416	471	539	635	791	558	590	688	769	1007	34.1	25.2	27.7	21.1	27.3
02YA002	18	21	26	32	43	16	17	20	23	31	-13.8	-21.4	-22.0	-28.3	-27.5
03NE001	23	25	28	32	38	20	21	25	27	35	-10.2	-15.2	-12.2	-15.3	-8.5
03NE002	5	6	7	8	10	7	8	9	10	12	45.7	32.3	31.5	20.5	22
03NF001	1370	1540	1760	2060	2540	1230	1270	1449	1573	1982	-10.2	-17.5	-17.7	-23.6	-22
03NG001	1500	1750	2070	2550	3350	1527	1579	1802	1959	2471	1.8	-9.8	-13.0	-23.2	-26.2
03OC003	1370	1500	1650	1860	2180	2060	2110	2385	2563	3179	50.4	40.7	44.5	37.8	45.8
03OD007	212	238	268	311	378	302	312	356	386	486	42.6	31.1	32.7	24	28.5
03OE003	292	330	377	442	548	243	244	269	281	335	-16.6	-26.0	-28.6	-36.5	-38.8
03OE010	17	19	21	24	29	19	20	23	25	32	10.7	4.3	7.1	2.5	9.7
03OE011	145	164	188	222	276	165	172	198	217	277	14.0	5.0	5.3	-2.3	0.5
03PB002	563	625	698	801	959	598	608	683	728	894	6.2	-2.7	-2.1	-9.1	-6.8
03QC001	2210	2510	2870	3400	4250	1990	2073	2384	2616	3338	-9.9	-17.4	-16.9	-23.1	-21.5
03QC002	625	722	843	1020	1310	833	892	1055	1198	1603	33.2	23.6	25.2	17.5	22.3
02UC002	2710	3070	3490	4100	5080	2903	2999	3417	3708	4660	7.1	-2.3	-2.1	-9.6	-8.3
02UC003	540	599	669	766	916	603	625	715	779	986	11.7	4.3	6.8	1.6	7.6
02VA001	250	308	384	503	722	250	269	318	361	484	0.1	-12.8	-17.3	-28.2	-33
02VB003	1260	1400	1560	1790	2130	1413	1472	1692	1856	2367	12.1	5.2	8.5	3.7	11.1
02VB004	1080	1240	1440	1730	2200	1341	1398	1606	1761	2246	24.2	12.7	11.5	1.8	2.1
02VC001	1950	2230	2590	3100	3930	2125	2201	2515	2739	3460	9.0	-1.3	-2.9	-11.6	-12
02WA001	453	507	571	662	805	502	530	617	689	900	10.7	4.5	8.1	4	11.8
02WA002	1080	1180	1300	1470	1720	1100	1149	1324	1456	1866	1.9	-2.6	1.8	-0.9	8.5
02WB002	2150	2390	2670	3060	3680	1907	1976	2259	2462	3113	-11.3	-17.3	-15.4	-19.5	-15.4
02WB003	1940	2180	2470	2880	3530	2491	2580	2948	3210	4053	28.4	18.4	19.4	11.5	14.8
02WC001	553	639	746	902	1160	604	635	736	816	1057	9.2	-0.7	-1.3	-9.5	-8.9
02XA006	3050	3390	3800	4370	5250	3325	3455	3960	4329	5495	9.0	1.9	4.2	-0.9	4.7
02XA007	1990	2240	2530	2930	3580	2301	2399	2760	3031	3871	15.6	7.1	9.1	3.4	8.1
02XB001	1510	1710	1950	2300	2850	1396	1467	1699	1882	2432	-7.6	-14.2	-12.9	-18.2	-14.7
02XB002	143	155	169	188	215	207	214	245	267	338	44.5	38.3	45.0	41.9	57.2
02XC001	1580	1850	2180	2670	3490	1535	1630	1910	2145	2826	-2.8	-11.9	-12.4	-19.7	-19

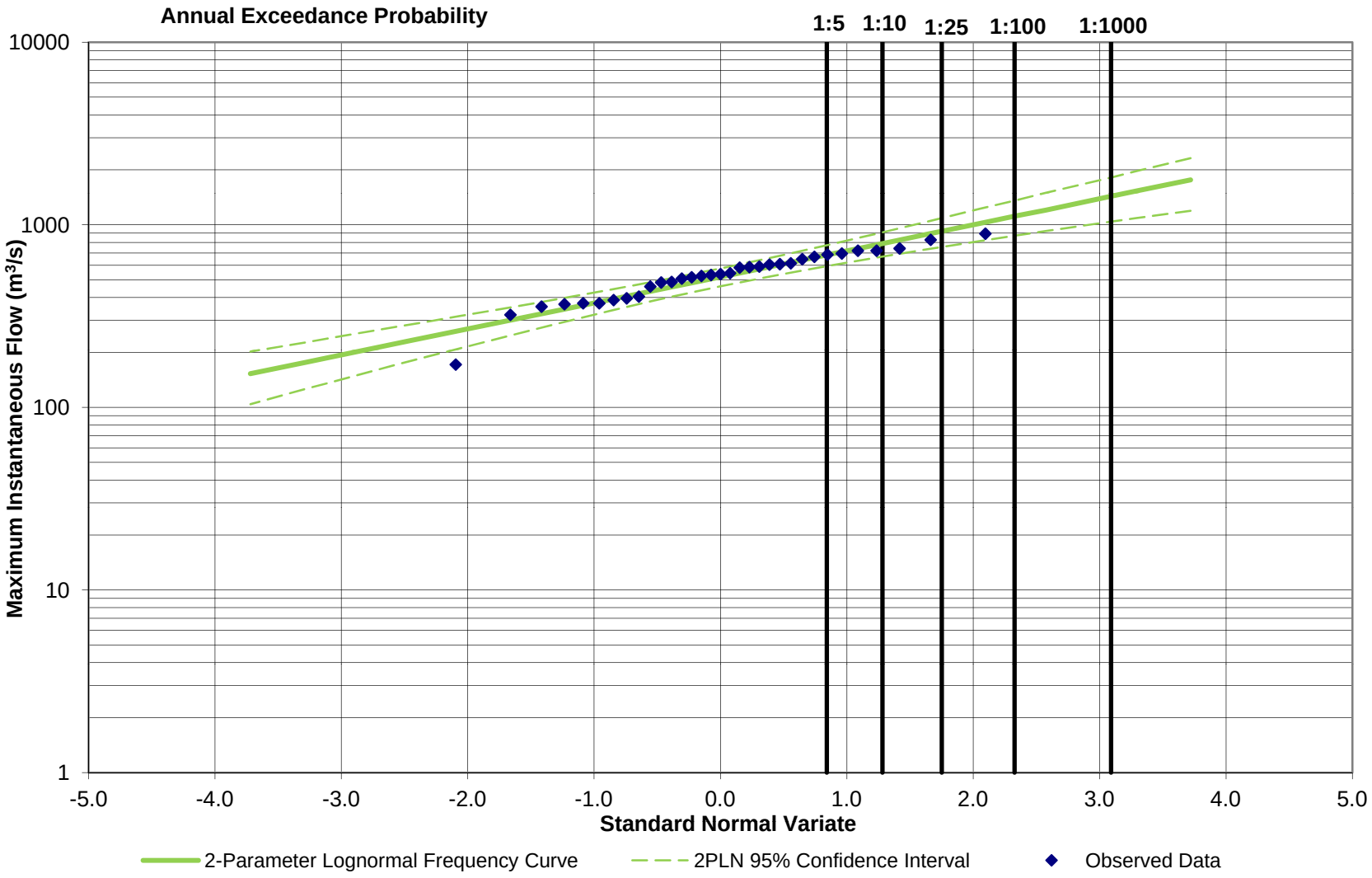


Figure C-16
Flood Frequency Plot - Site ALX
Coastal Labrador Small Hydro Feasibility Study
Newfoundland Labrador Hydro

Photo Log C-17

Client	Newfoundland and Labrador Hydro	**Sheet**	1 of 3
Site	Hydrometric Gauge Photos	**Date**	2012-11-27

Photo No.	Site	Description
Photo 1	8	Site 8 Gauge Shelter
Photo 2	8	Site 8 Landing Pad
Photo 3	8	Site 8 Landing Pad
Photo 4	8	Clearing Wood at Site 8
Photo 5	8	Site 8 Landing Pad
Photo 6	8	Site 8 Gauge Shelter
Photo 7	8	Helicopter Approaching Site 8 Landing Pad
Photo 8	8	Site 8 Gauge Shelter
Photo 9	ALX	Alexis River Hydrometric Gauge Hut (03QC002)
Photo 10	ALX	Section of River at Alexis River Hydrometric Gauge
Photo 11	ALX	Existing Hydrometric Gauge Located Immediately Upstream of Site ALX
Photo 12	ALX	Site ALX Landing Pad

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Photo 1 – Site 8 Gauge Shelter



Photo 2 – Site 8 Landing Pad



Photo 3 – Site 8 Landing Pad



Photo 4 – Clearing Wood at Site 8



Photo 5 – Site 8 Landing Pad



Photo 6 – Site 8 Gauge Shelter

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Photo 7– Helicopter Approaching Site 8 Landing Pad



Photo 8 – Interior of Site 8 Gauge Shelter



Photo 9 – Alexis River Hydrometric Gauge Hut (03QC002)



Photo 10 – Section of River at Alexis River Hydrometric Gauge



Photo 11 – Existing Hydrometric Gauge Immediately Upstream of Site ALX



Photo 12 – Site ALX Landing Pad

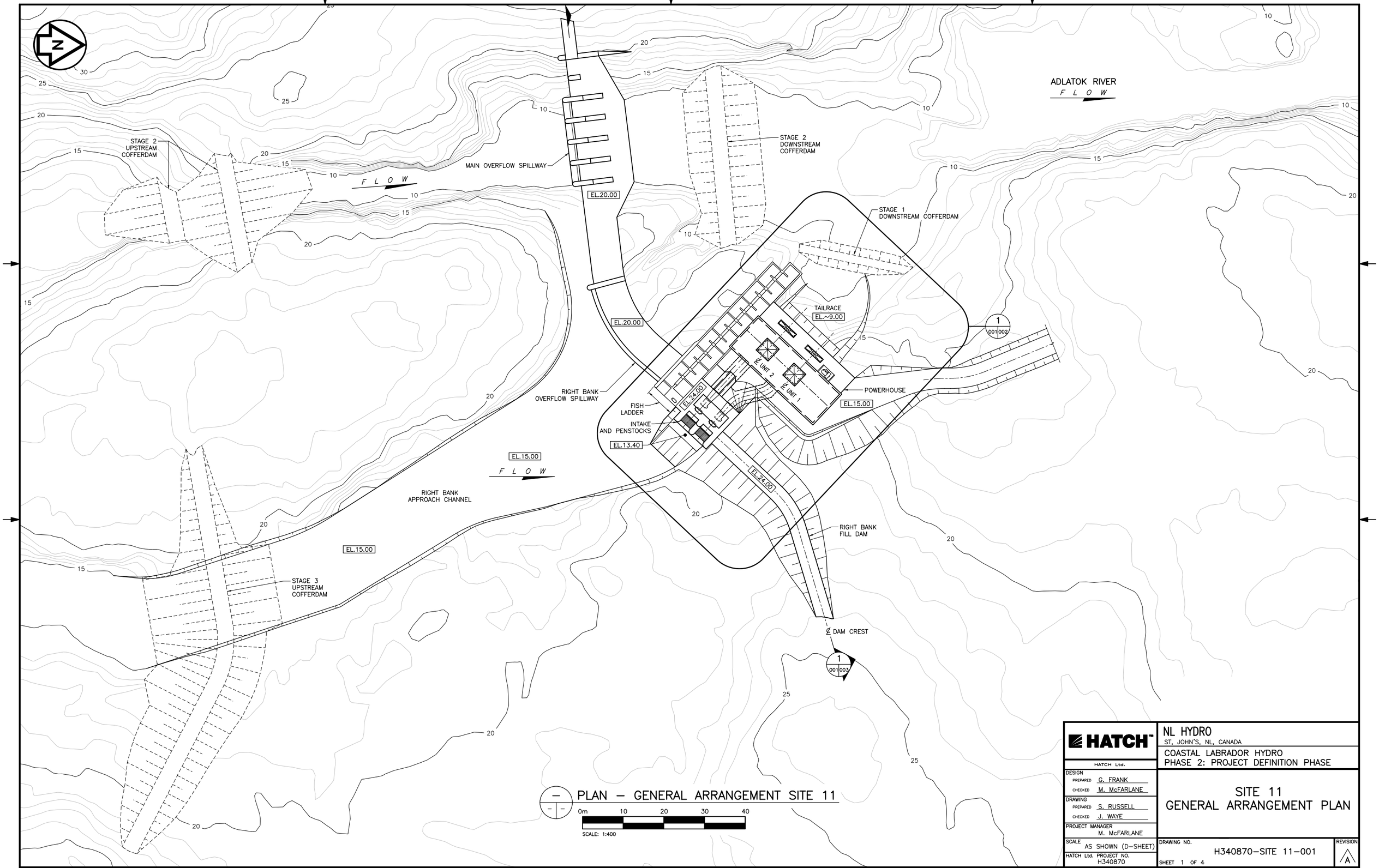
WorkingTogether SAFELY

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Appendix D

Drawings

Safety • Quality • Sustainability • Innovation



PLAN – GENERAL ARRANGEMENT SITE 11

0m 10 20 30 40

SCALE: 1:400

HATCH

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NL HYDRO
ST. JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

SITE 11
GENERAL ARRANGEMENT PLAN

DESIGN PREPARED	G. FRANK
DESIGN CHECKED	M. McFARLANE
DRAWING PREPARED	S. RUSSELL
DRAWING CHECKED	J. WAYE
PROJECT MANAGER	M. McFARLANE
SCALE	AS SHOWN (D–SHEET)
HATCH Ltd. PROJECT NO.	H340870
DRAWING NO.	H340870–SITE 11–001
REVISION	A

SHEET 1 OF 4

FISH LADDER

0.75
6.50
1.80
1.50
3.20
1.50
3.20

1.50
8.00
10.70
15.10
2.40
1.10
2.00
5.20
27.40
9.00

EL.15.00
℄ PENSTOCK 2
EL.13.40
EL.24.00
℄ PENSTOCK 1
ø 2.20m PENSTOCKS
INTAKE STRUCTURE
HATCH AND COVER (TYP.)
DRAFT TUBE GATE SLOT COVER (TYP.)
EL.15.00
EL.~9.00
℄ UNIT 2
℄ UNIT 1
EL.15.00
EL.24.00
EL.15.00

A 002|004
B 002|004
C 002|004

STAGE 1 DOWNSTREAM COFFERDAM

15
10
20

1 002|001 PLAN – GENERAL ARRANGEMENT AT INTAKE

0m 2 4 6 8 10
SCALE: 1:100

HATCH

HATCH Ltd.

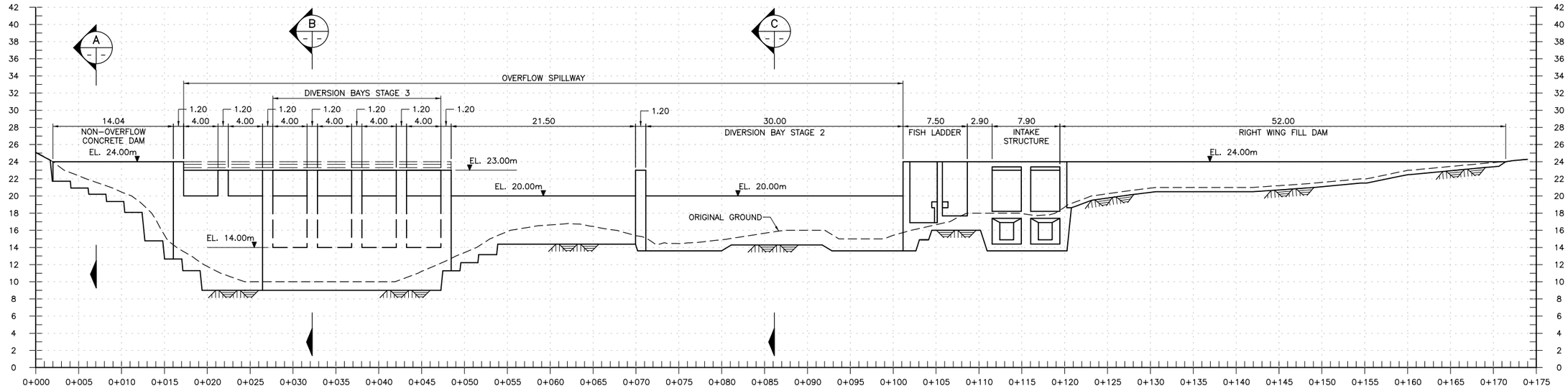
NL HYDRO
ST, JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

SITE 11 – PARTIAL PLAN
INTAKE AND POWERHOUSE

DESIGN
PREPARED G. FRANK
CHECKED M. McFARLANE
DRAWING
PREPARED S. RUSSELL
CHECKED J. WAYE
PROJECT MANAGER M. McFARLANE
SCALE 1:100 (D–SHEET)
HATCH Ltd. PROJECT NO. H340870

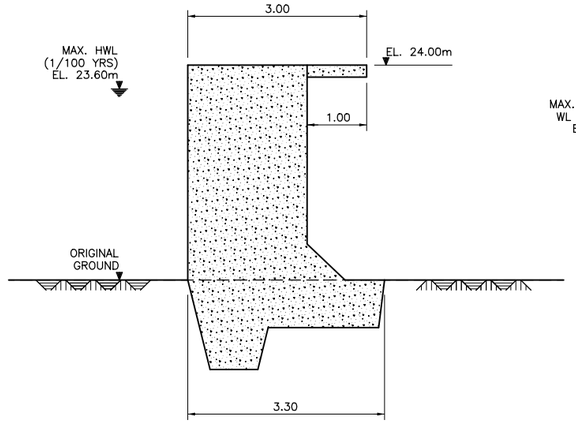
DRAWING NO. H340870–SITE 11–002
SHEET 2 OF 4
REVISION A



1 (003|001) PROFILE – DAM, SPILLWAY, FISH LADDER, INTAKE AND WING DAM

0m 5 10 15 20 25

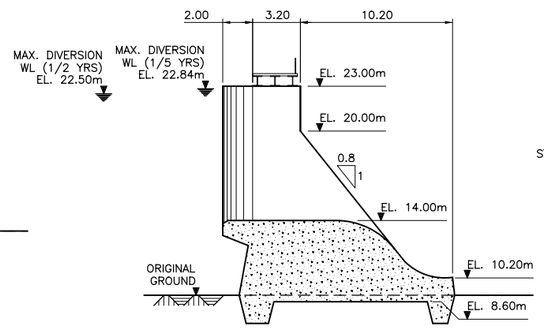
SCALE: 1:250



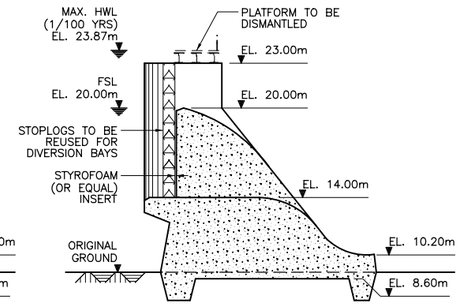
A SECTION – NON-OVERFLOW DAM

0m 1 2 3 4 5

SCALE: 1:50



DIVERSION STAGE 3

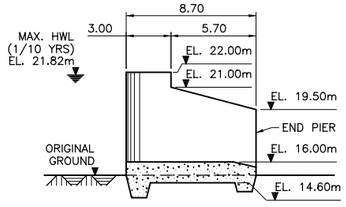


FINAL STAGE

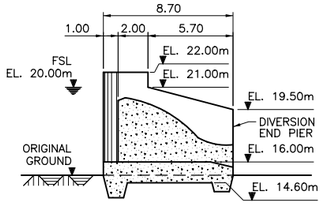
B SECTION – DIVERSION AND OVERFLOW SPILLWAY

0m 4 8 12 16 20

SCALE: 1:200



DIVERSION STAGE 2



FINAL STAGE

C SECTION – DIVERSION AND OVERFLOW SPILLWAY

0m 4 8 12 16 20

SCALE: 1:200

HATCH

HATCH Ltd.

NL HYDRO
ST, JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

DESIGN
PREPARED G. FRANK
CHECKED M. McFARLANE

DRAWING
PREPARED S. RUSSELL
CHECKED J. WAYE

PROJECT MANAGER
M. McFARLANE

SCALE
AS SHOWN (D-SHEET)

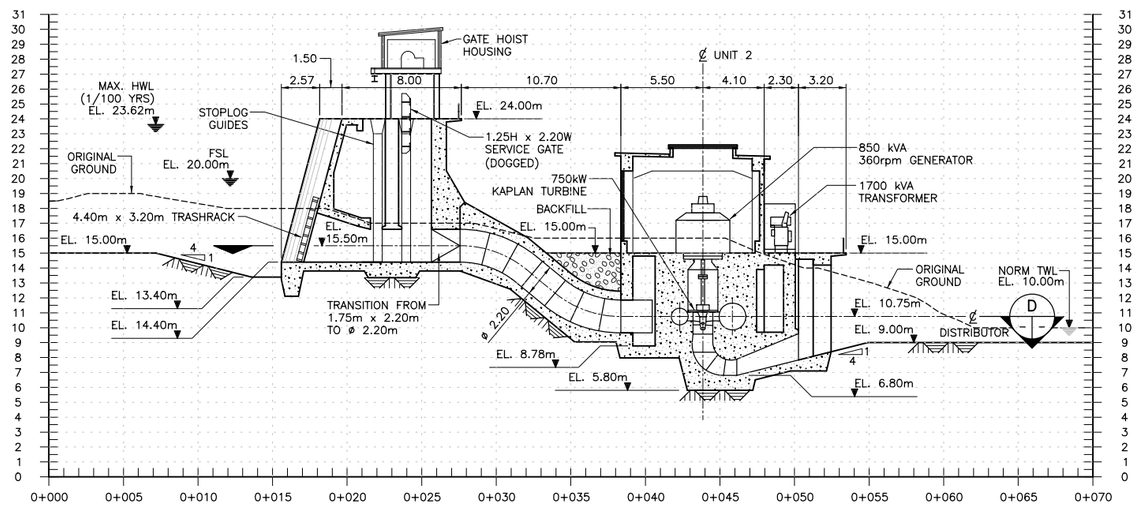
HATCH Ltd. PROJECT NO.
H340870

SITE 11
PROFILE AND SECTIONS

DRAWING NO.
H340870-SITE 11-003

REVISION
A

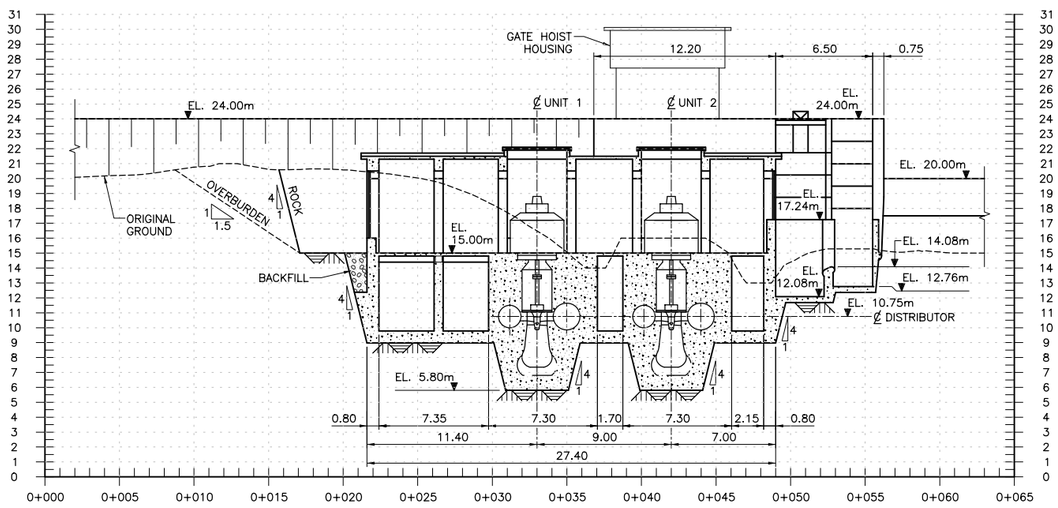
SHEET 3 OF 4



A 004|002 SECTION – CENTERLINE OF INTAKE, PENSTOCK AND UNIT #2

0m 4 8 12 16 20

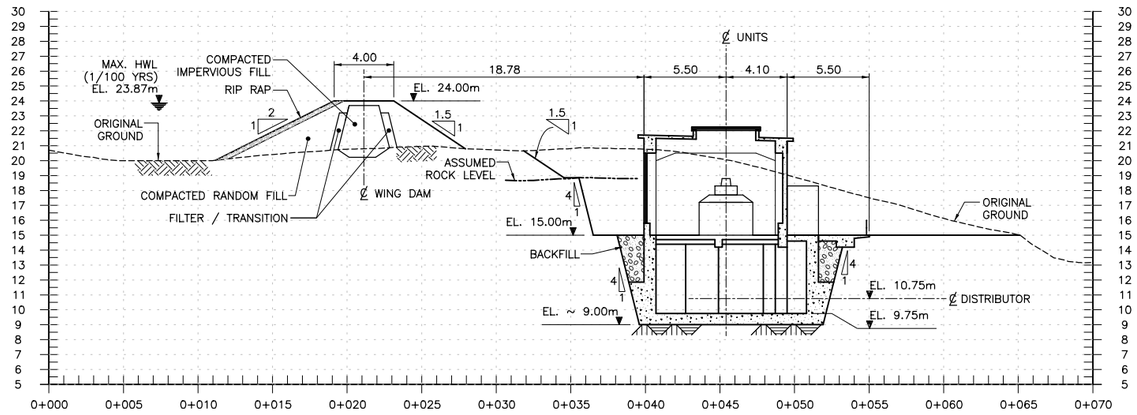
SCALE: 1:200



C 004|002 SECTION – CENTERLINE OF UNITS

0m 4 8 12 16 20

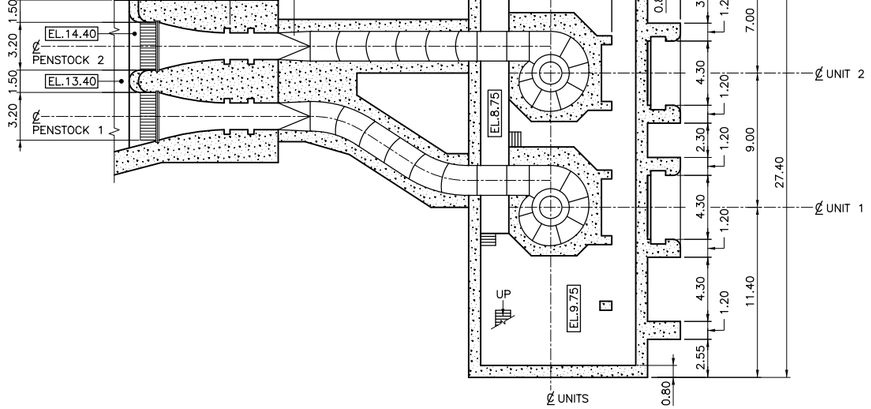
SCALE: 1:200



B 004|002 SECTION – RIGHT WING DAM AND POWERHOUSE

0m 4 8 12 16 20

SCALE: 1:200



D - - SECTION – INTAKE, PENSTOCK AND POWERHOUSE

0m 4 8 12 16 20

SCALE: 1:200

HATCH

HATCH Ltd.

NL HYDRO
ST, JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

DESIGN
PREPARED G. FRANK
CHECKED M. McFARLANE

DRAWING
PREPARED S. RUSSELL
CHECKED J. WAYE

PROJECT MANAGER
M. McFARLANE

SCALE
1:200 (D-SHEET)

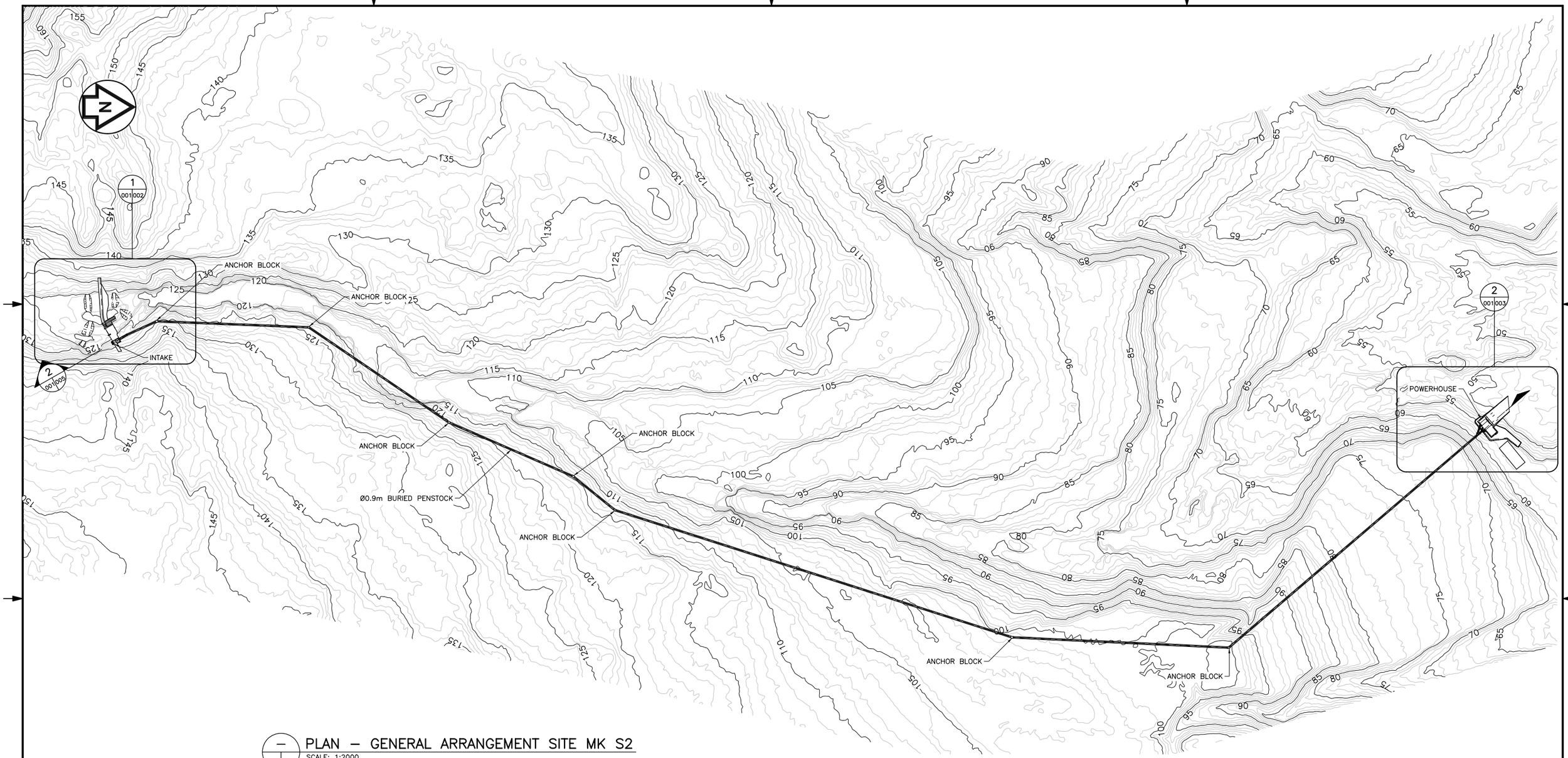
HATCH Ltd. PROJECT NO.
H340870

SITE 11 – SECTIONS

DRAWING NO.
H340870-SITE 11-004

REVISION
A

SHEET 4 OF 4



PLAN – GENERAL ARRANGEMENT SITE MK S2

SCALE: 1:2000

0m 40 80 120 160 200

SCALE: 1:2000

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NL HYDRO
ST. JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

SITE MK S–2 – GENERAL ARRANGEMENT PLAN

DESIGN PREPARED	G. FRANK
DESIGN CHECKED	M. McFARLANE
DRAWING PREPARED	J. WAYE
DRAWING CHECKED	S. RUSSELL
PROJECT MANAGER	M. McFARLANE
SCALE	AS SHOWN (D–SHEET)
HATCH Ltd. PROJECT NO.	H340870
DRAWING NO.	H340870–SITE MK S–2–001
SHEET	1 OF 6
REVISION	A

N

1
002 004

NON–OVERFLOW CONCRETE DAM

EL. 131.50

STAGE 2 UPSTREAM COFFERDAM

EL. 125.50

STAGE 2 DOWNSTREAM COFFERDAM

EL. 124.00

MAKKOVIK BROOK

F L O W

FISH PASSAGE

STAGE 1 DOWNSTREAM COFFERDAM

EL. 124.00

CONCRETE ANCHOR BLOCK

DIVERSION OUTLET

STAGE 1 UPSTREAM COFFERDAM

EL. 125.50

Ø0.9m BURIED PENSTOCK (SEE DRAWING 005)

OVERFLOW SPILLWAY

EL. 125.50

INTAKE STRUCTURE

F L O W

135 130 125 120 125 130 135 130 125 125 130 135 140 135 140

1
002 001 PLAN – GENERAL ARRANGEMENT AT INTAKE

SCALE: 1:250

0m 5 10 15 20 25

SCALE: 1:250

HATCH

HATCH Ltd.

DESIGN PREPARED	G. FRANK
DESIGN CHECKED	M. McFARLANE
DRAWING PREPARED	J. WAYE
DRAWING CHECKED	S. RUSSELL
PROJECT MANAGER	M. McFARLANE
SCALE	AS SHOWN (D–SHEET)
HATCH Ltd. PROJECT NO.	H340870

NL HYDRO
ST. JOHN'S, NL, CANADA

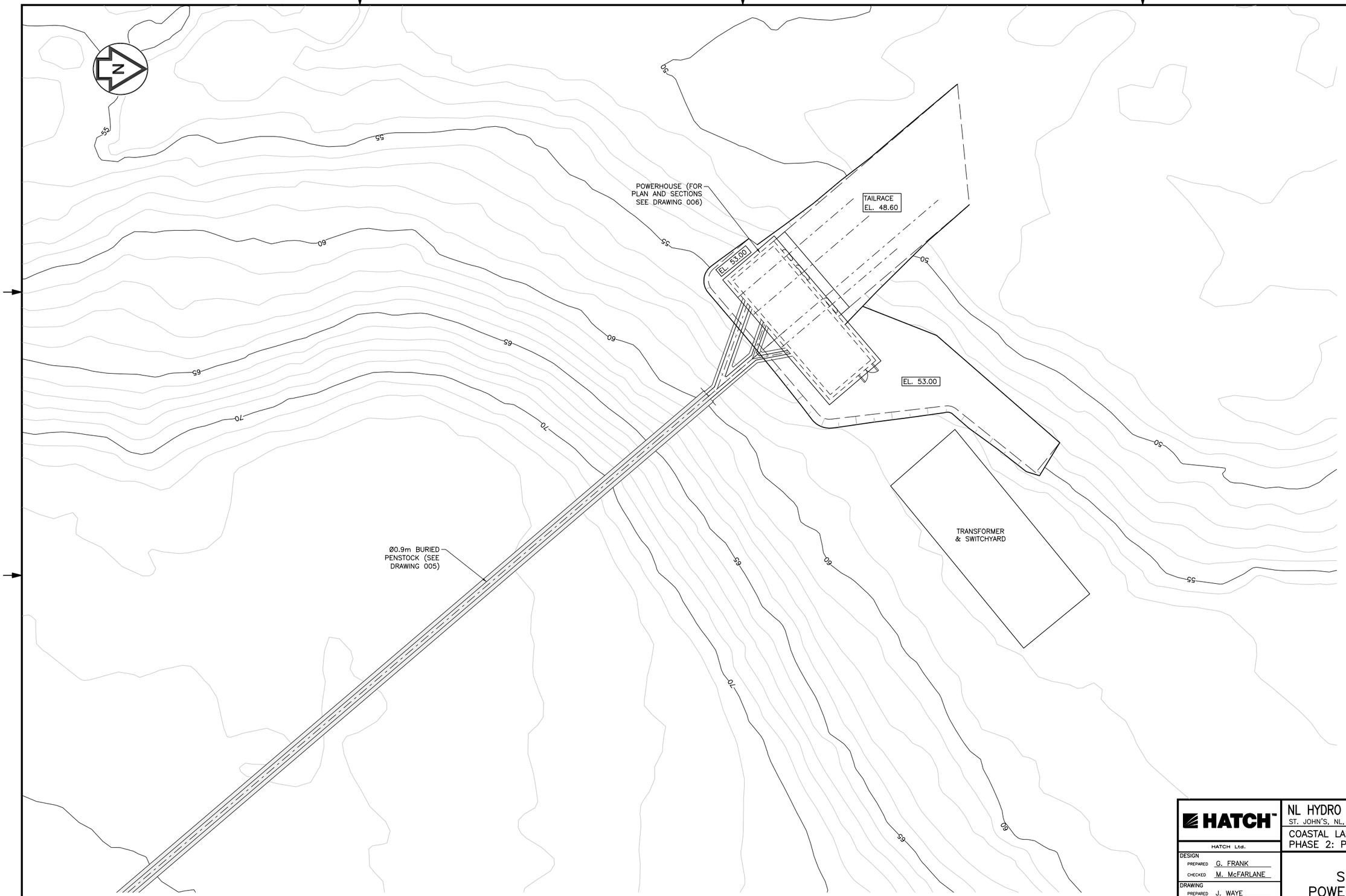
COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

SITE MK S–2 – PLAN COFFERDAMS, DAM, INTAKE, AND SPILLWAY

DRAWING NO. H340870–SITE MK S–2–002

REVISION A

SHEET 2 OF 6



2 / 003 | 001 PLAN – GENERAL ARRANGEMENT AT POWERHOUSE

SCALE: 1:250

0m 5 10 15 20 25

SCALE: 1:250

HATCH

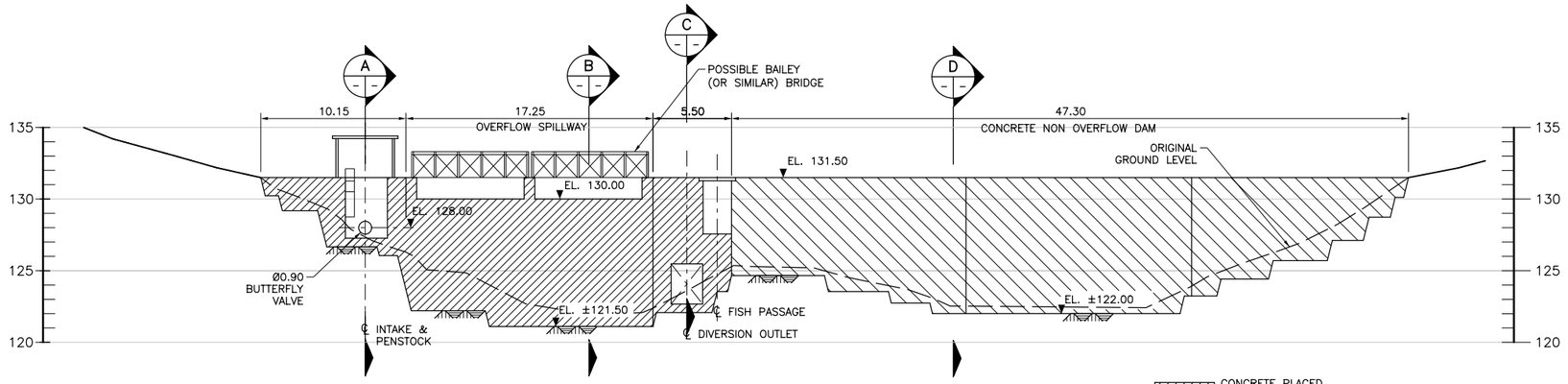
HATCH Ltd.

NL HYDRO
ST. JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

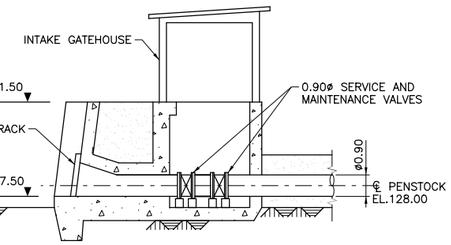
SITE MK S–2 –
POWERHOUSE SITE PLAN

DESIGN PREPARED	G. FRANK
DESIGN CHECKED	M. McFARLANE
DRAWING PREPARED	J. WAYE
DRAWING CHECKED	S. RUSSELL
PROJECT MANAGER	M. McFARLANE
SCALE	AS SHOWN (D–SHEET)
HATCH Ltd. PROJECT NO.	H340870
DRAWING NO.	H340870–SITE MK S–2–003
REVISION	A
SHEET	3 OF 6



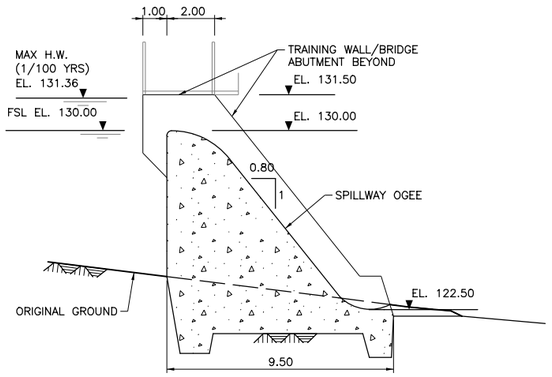
1 | 004 002 PROFILE – INTAKE, SPILLWAY, DIVERSION OUTLET AND DAM

SCALE: 1:200



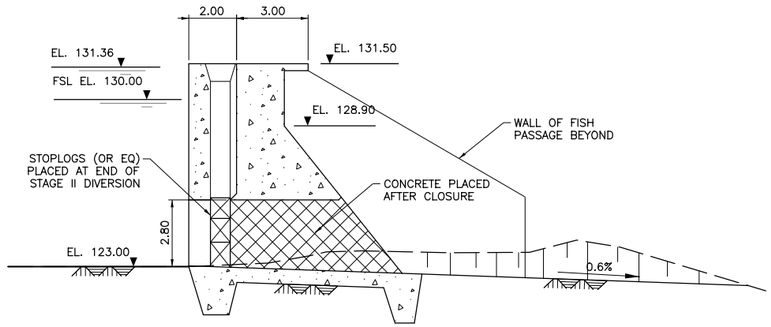
A | – – SECTION – INTAKE STRUCTURE

SCALE: 1:125



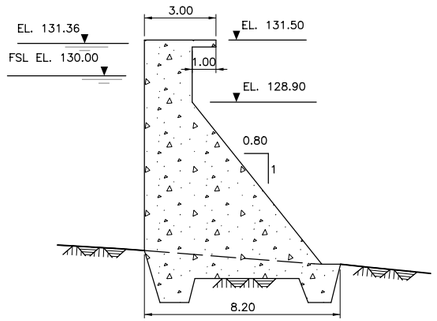
B | – – SECTION – OVERFLOW SPILLWAY

SCALE: 1:125



C | – – SECTION – DIVERSION OUTLET

SCALE: 1:125



D | – – SECTION – NON–OVERFLOW DAM

SCALE: 1:125

0m 4 8 12 16 20

SCALE: 1:200

0m 2.5 5 7.5 10 12.5

SCALE: 1:125

HATCH

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NL HYDRO
ST. JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

SITE MK S–2 –
DAM, INTAKE, SPILLWAY
PROFILE AND SECTIONS

DESIGN
PREPARED G. FRANK
CHECKED M. McFARLANE

DRAWING
PREPARED J. WAYE
CHECKED S. RUSSELL

PROJECT MANAGER
M. McFARLANE

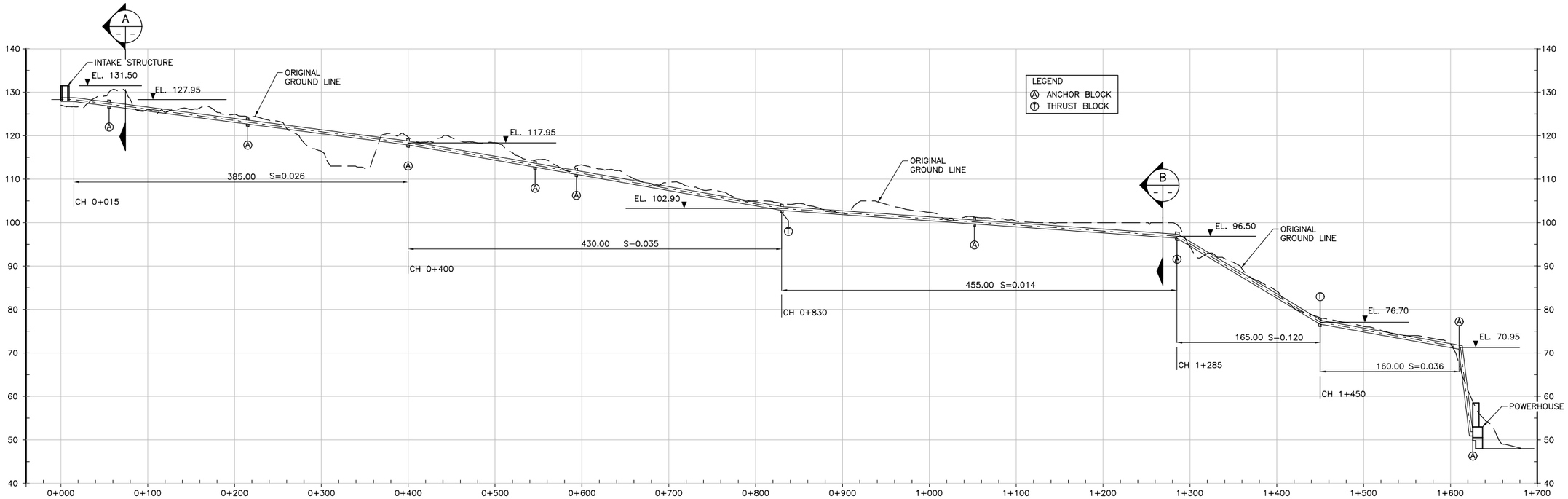
SCALE
AS SHOWN (D–SHEET)

HATCH Ltd. PROJECT NO.
H340870

DRAWING NO.
H340870–SITE MK S–2–004

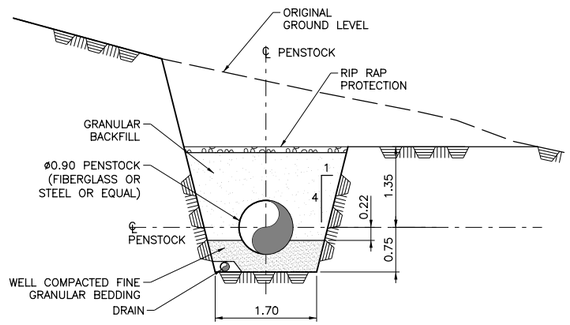
REVISION
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SHEET 4 OF 6



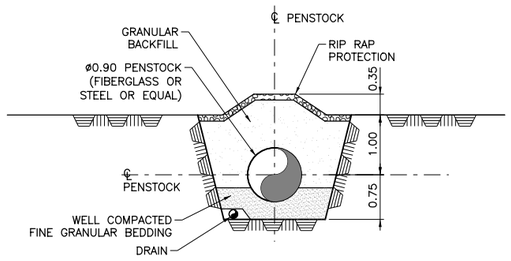
2 005 001 PROFILE – INTAKE, PENSTOCK AND POWERHOUSE

SCALE: 1:500 VERTICAL – 1:2500 HORIZONTAL



A - - SECTION – PENSTOCK

SCALE: 1:50



B - - SECTION – PENSTOCK

SCALE: 1:50

0m 50 100 150 200 250
SCALE: 1:2500

0m 10 20 30 40 50
SCALE: 1:500

0m 1 2 3 4 5
SCALE: 1:50

HATCH Ltd.

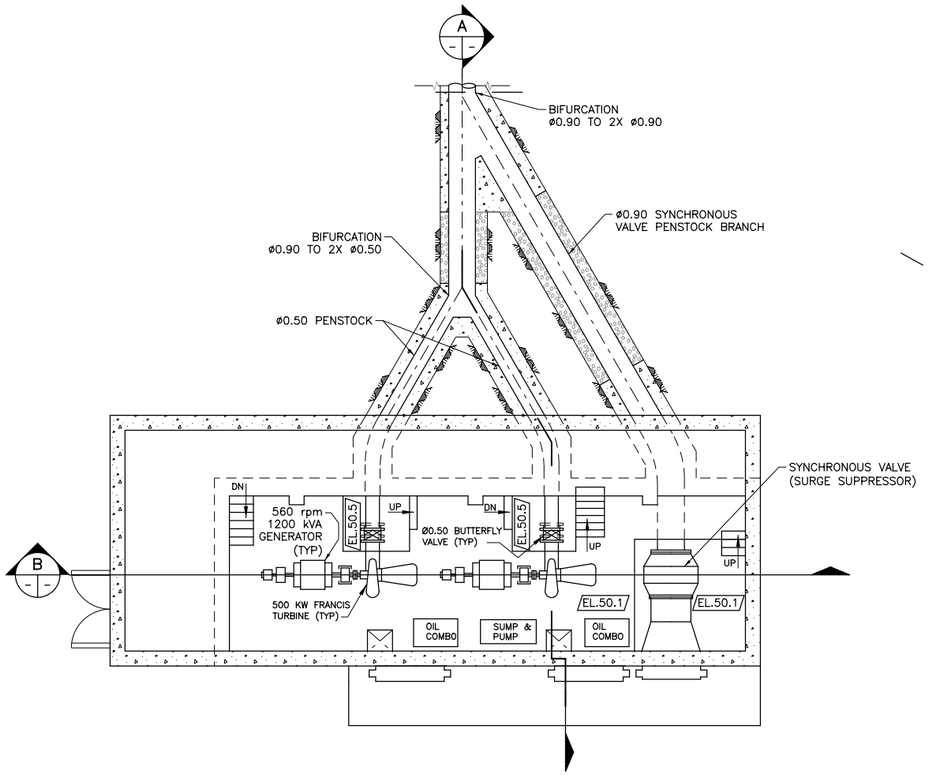
DESIGN
PREPARED G. FRANK
CHECKED M. McFARLANE
DRAWING
PREPARED J. WAYE
CHECKED S. RUSSELL
PROJECT MANAGER M. McFARLANE
SCALE AS SHOWN (D-SHEET)
HATCH Ltd. PROJECT NO. H340870

NL HYDRO
ST. JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

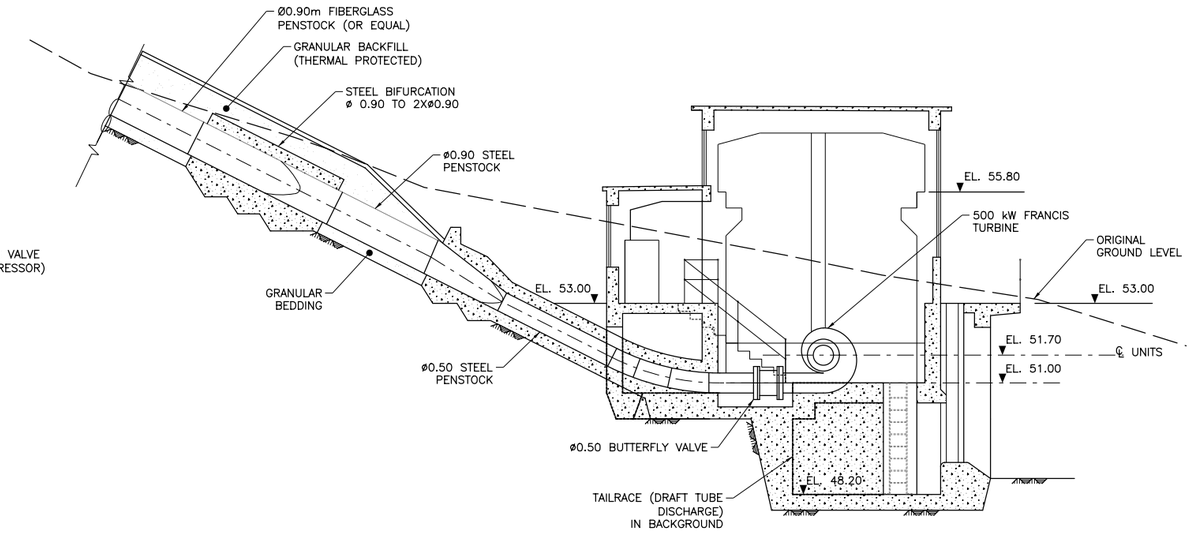
SITE MK S-2 – PENSTOCK PROFILE AND SECTIONS

DRAWING NO. H340870-SITE MK S-2-005
REVISION A
SHEET 5 OF 6



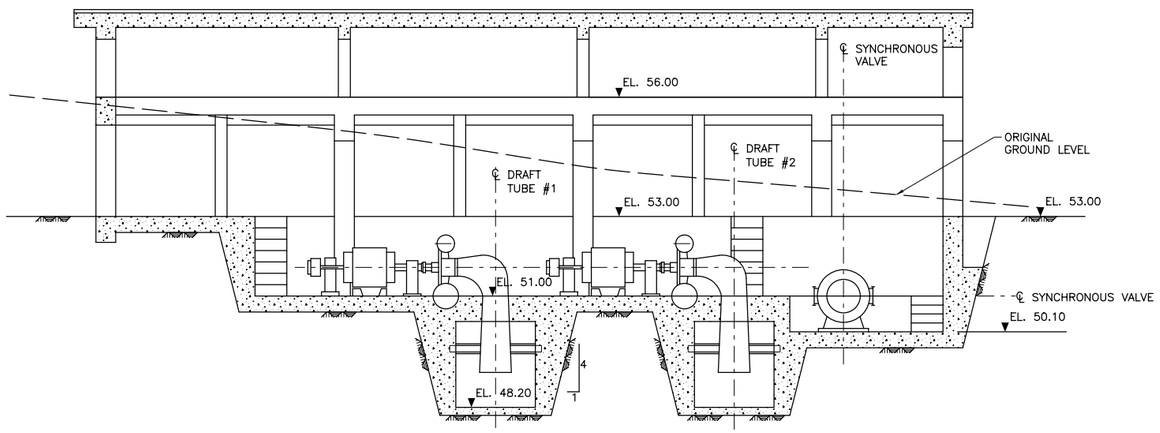
3 PLAN – POWERHOUSE BIFURCATION GENERAL ARRANGEMENT

SCALE: 1:100



A SECTION – POWERHOUSE UNIT 2

SCALE: 1:75



B SECTION – POWERHOUSE AT CENTERLINE OF UNIT 1 & UNIT 2

SCALE: 1:75

0m 2 4 6 8 10
SCALE: 1:100

0m 1.5 3 4.5 6 7.5
SCALE: 1:75

HATCH

HATCH Ltd.

NL HYDRO
ST. JOHN'S, NL, CANADA

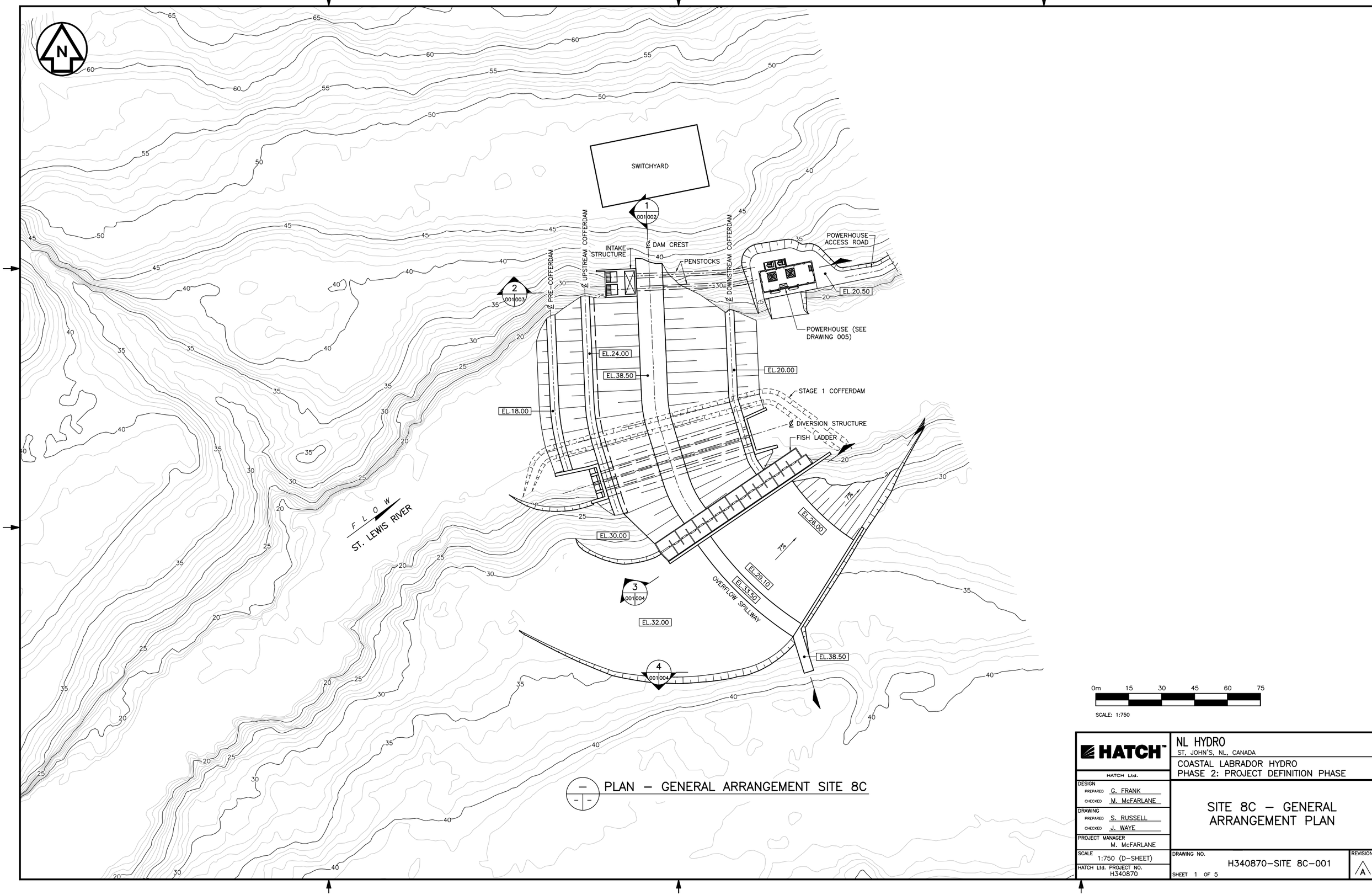
COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

SITE MK S–2 –
POWERHOUSE
PLAN AND SECTIONS

DESIGN
PREPARED G. FRANK
CHECKED M. McFARLANE
DRAWING
PREPARED J. WAYE
CHECKED S. RUSSELL
PROJECT MANAGER
M. McFARLANE
SCALE
AS SHOWN (D–SHEET)
HATCH Ltd. PROJECT NO.
H340870

DRAWING NO.
H340870–SITE MK S–2–006
SHEET 6 OF 6

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A



PLAN – GENERAL ARRANGEMENT SITE 8C

HATCH

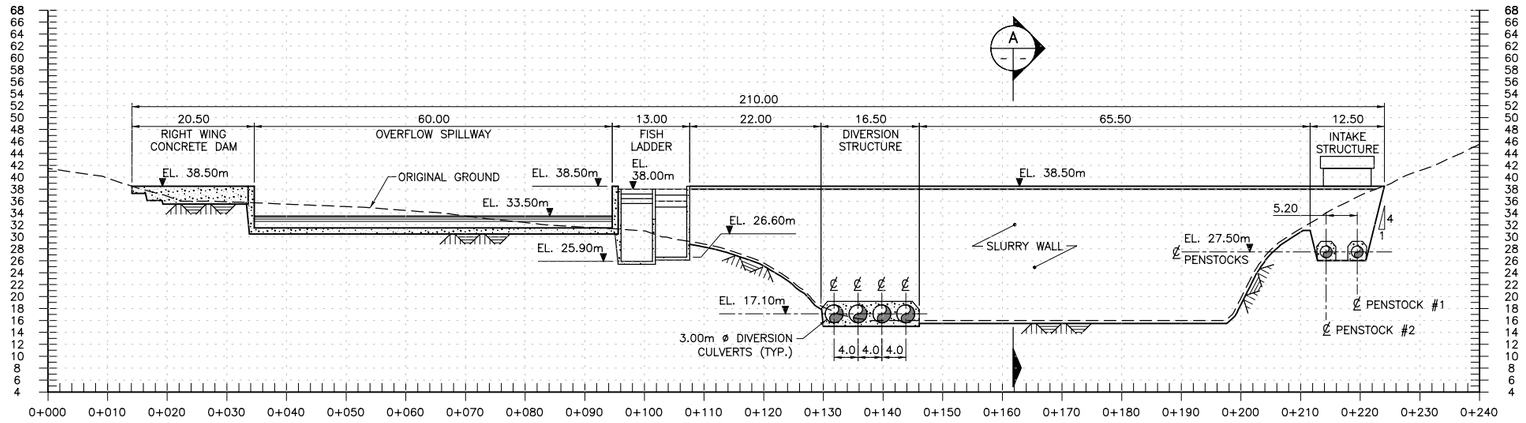
HATCH Ltd.

NL HYDRO
ST, JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

SITE 8C – GENERAL ARRANGEMENT PLAN

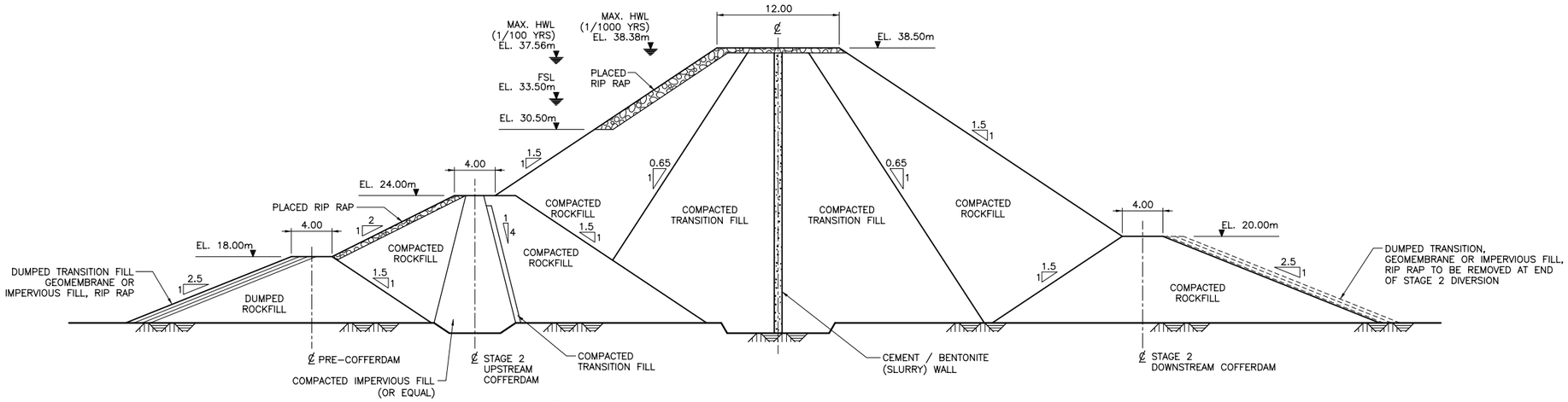
DESIGN PREPARED	G. FRANK
DESIGN CHECKED	M. McFARLANE
DRAWING PREPARED	S. RUSSELL
DRAWING CHECKED	J. WAYE
PROJECT MANAGER	M. McFARLANE
SCALE	1:750 (D-SHEET)
HATCH Ltd. PROJECT NO.	H340870
DRAWING NO.	H340870-SITE 8C-001
REVISION	A
SHEET	1 OF 5



1 002|001 PROFLE – RIGHT WING DAM, SPILLWAY, FISH LADDER, EMBANKMENT DAM AND INTAKE

0m 10 20 30 40 50

SCALE: 1:500



A – – SECTION – SLURRY WALL EMBANKMENT DAM

0m 5 10 15 20 25

SCALE: 1:250

HATCH

HATCH Ltd.

NL HYDRO
ST. JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

DESIGN
PREPARED G. FRANK
CHECKED M. McFARLANE

DRAWING
PREPARED S. RUSSELL
CHECKED J. WAYE

PROJECT MANAGER
M. McFARLANE

SCALE
AS SHOWN (D–SHEET)

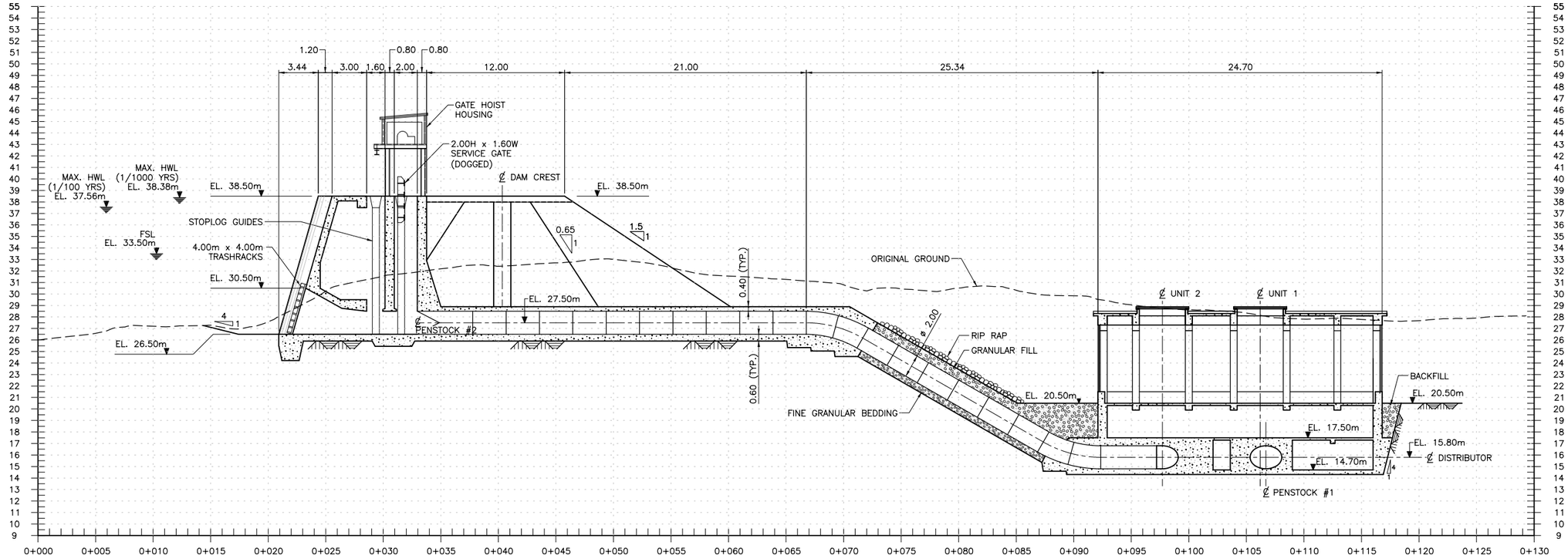
HATCH Ltd. PROJECT NO.
H340870

SITE 8C – PROFILE AND SECTION

DRAWING NO.
H340870–SITE 8C–002

REVISION
A

SHEET 2 OF 5



2
003 001

PROFILE – INTAKE, PENSTOCK, AND POWERHOUSE

0m 4 8 12 16 20

SCALE: 1:200

HATCH

HATCH Ltd.

DESIGN PREPARED	G. FRANK
DESIGN CHECKED	M. McFARLANE
DRAWING PREPARED	S. RUSSELL
DRAWING CHECKED	J. WAYE
PROJECT MANAGER	M. McFARLANE
SCALE	1:200 (D–SHEET)
HATCH Ltd. PROJECT NO.	H340870

NL HYDRO
ST, JOHN'S, NL, CANADA

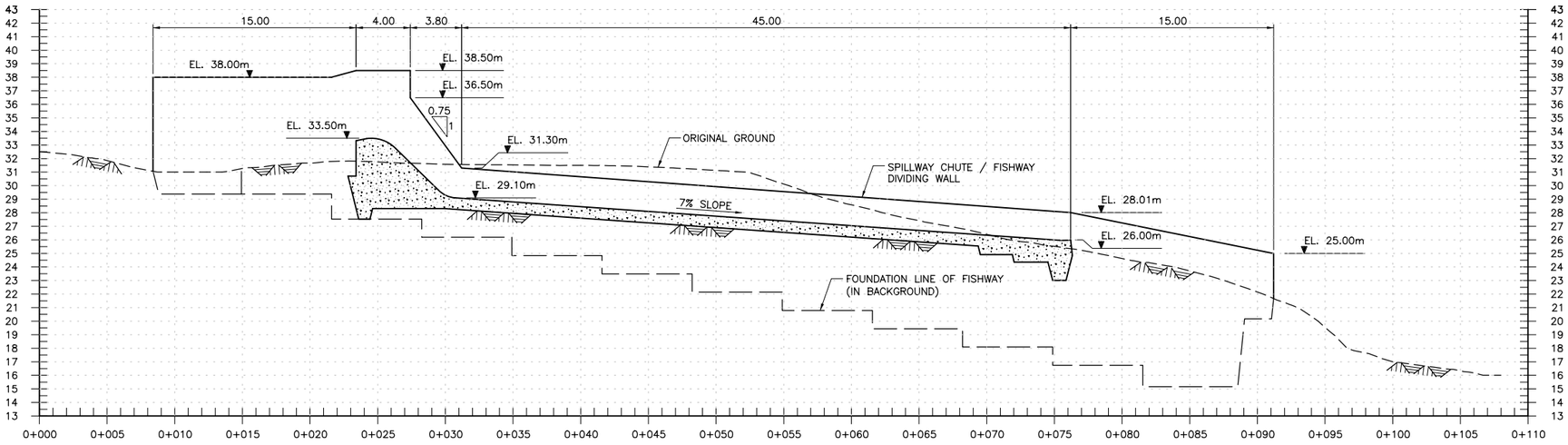
COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

SITE 8C – INTAKE, PENSTOCK, AND POWERHOUSE PROFILE

DRAWING NO. H340870–SITE 8C–003

REVISION A

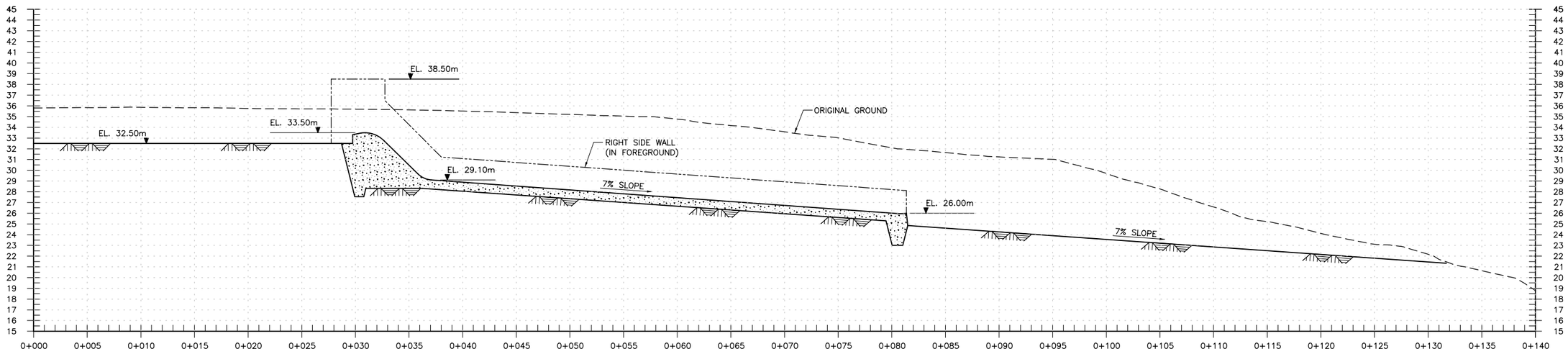
SHEET 3 OF 5



3 004 001 PROFILE – NORTH SIDE OF SPILLWAY CHUTE

0m 4 8 12 16 20

SCALE: 1:200



4 004 001 PROFILE – SOUTH SIDE OF SPILLWAY CHUTE

0m 4 8 12 16 20

SCALE: 1:200

HATCH

HATCH Ltd.

NL HYDRO
ST, JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

DESIGN
PREPARED G. FRANK
CHECKED M. McFARLANE

DRAWING
PREPARED S. RUSSELL
CHECKED J. WAYE

PROJECT MANAGER
M. McFARLANE

SCALE
1:200 (D–SHEET)

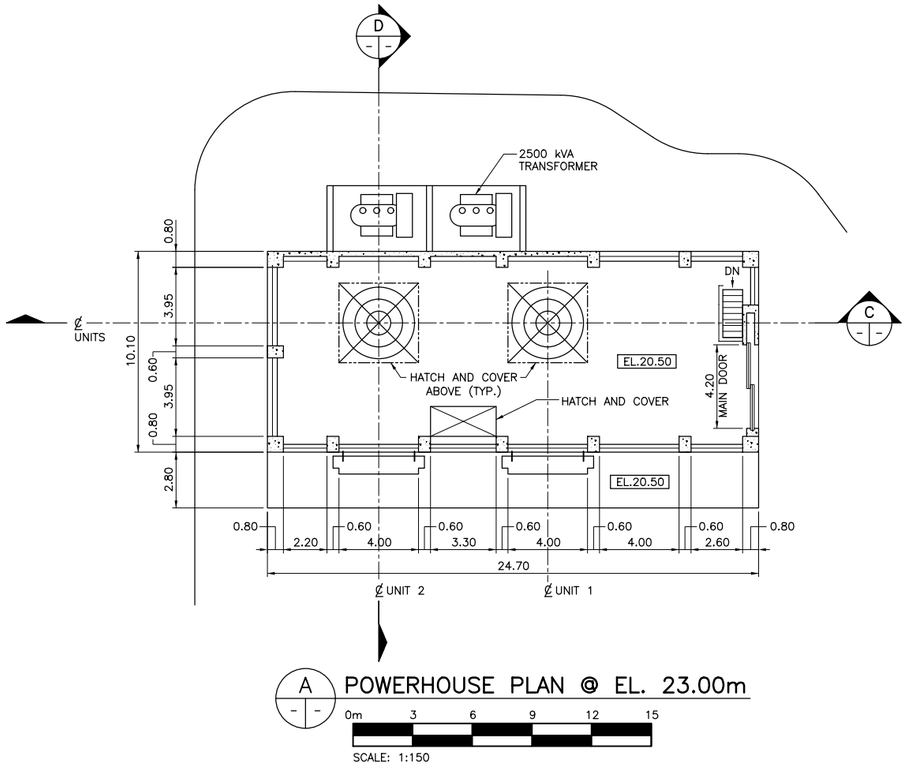
HATCH Ltd. PROJECT NO.
H340870

SITE 8C – SPILLWAY PROFILES

DRAWING NO.
H340870–SITE 8C–004

REVISION
A

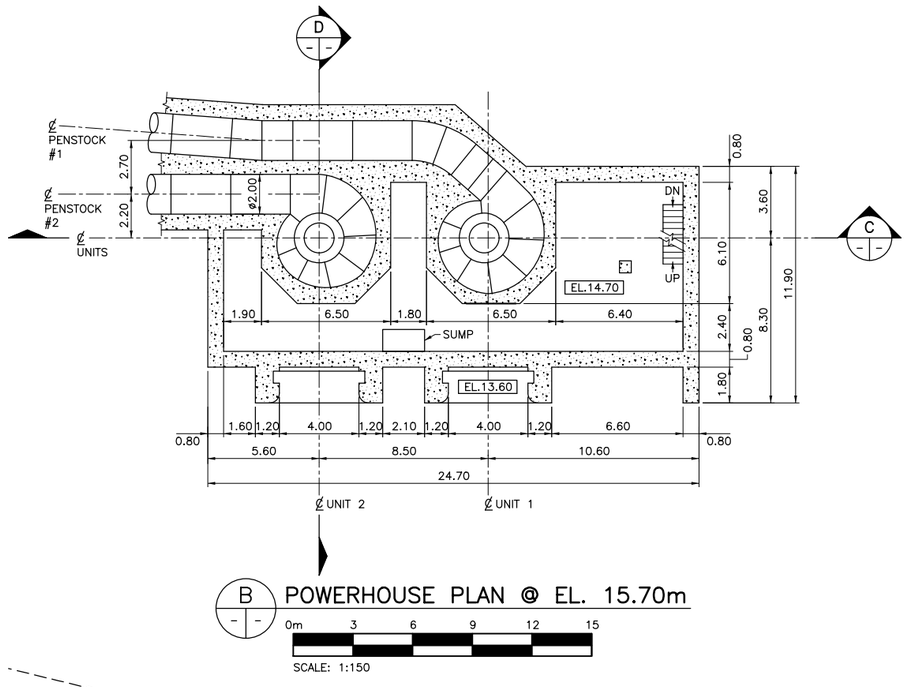
SHEET 4 OF 5



A POWERHOUSE PLAN @ EL. 23.00m

0m 3 6 9 12 15

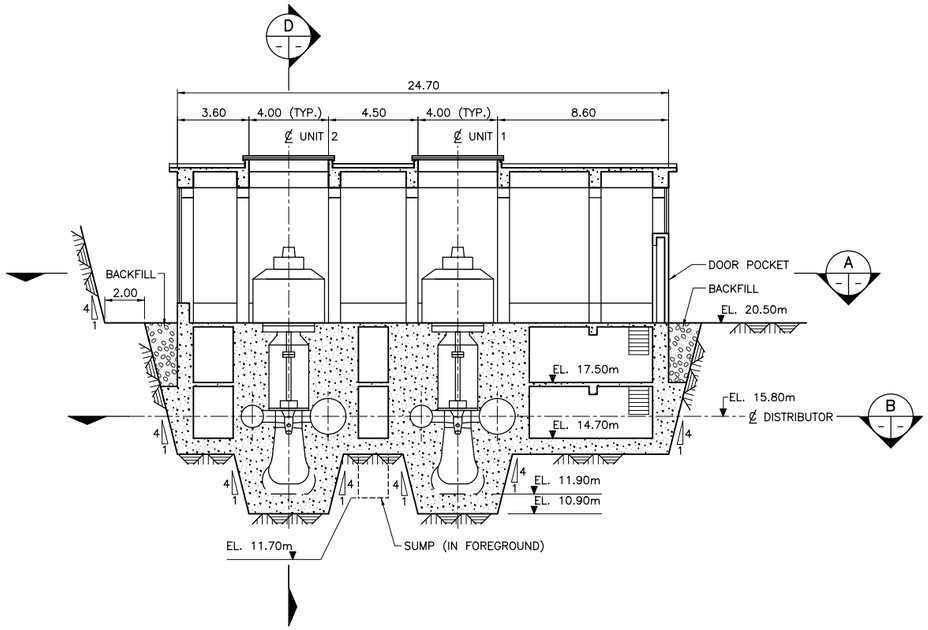
SCALE: 1:150



B POWERHOUSE PLAN @ EL. 15.70m

0m 3 6 9 12 15

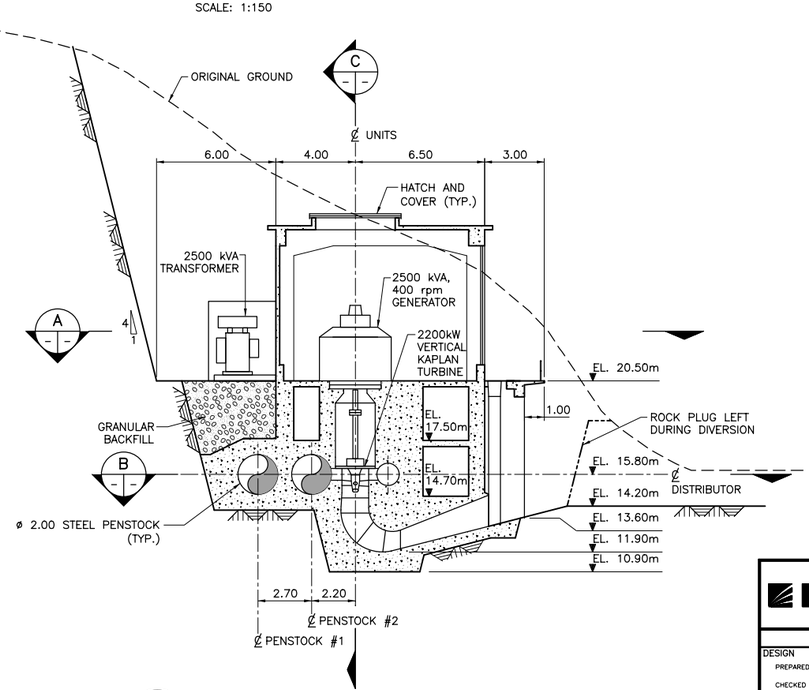
SCALE: 1:150



C SECTION – CENTERLINE OF UNITS #1 & #2

0m 3 6 9 12 15

SCALE: 1:150



D SECTION – CENTERLINE OF UNIT #2

0m 3 6 9 12 15

SCALE: 1:150

HATCH

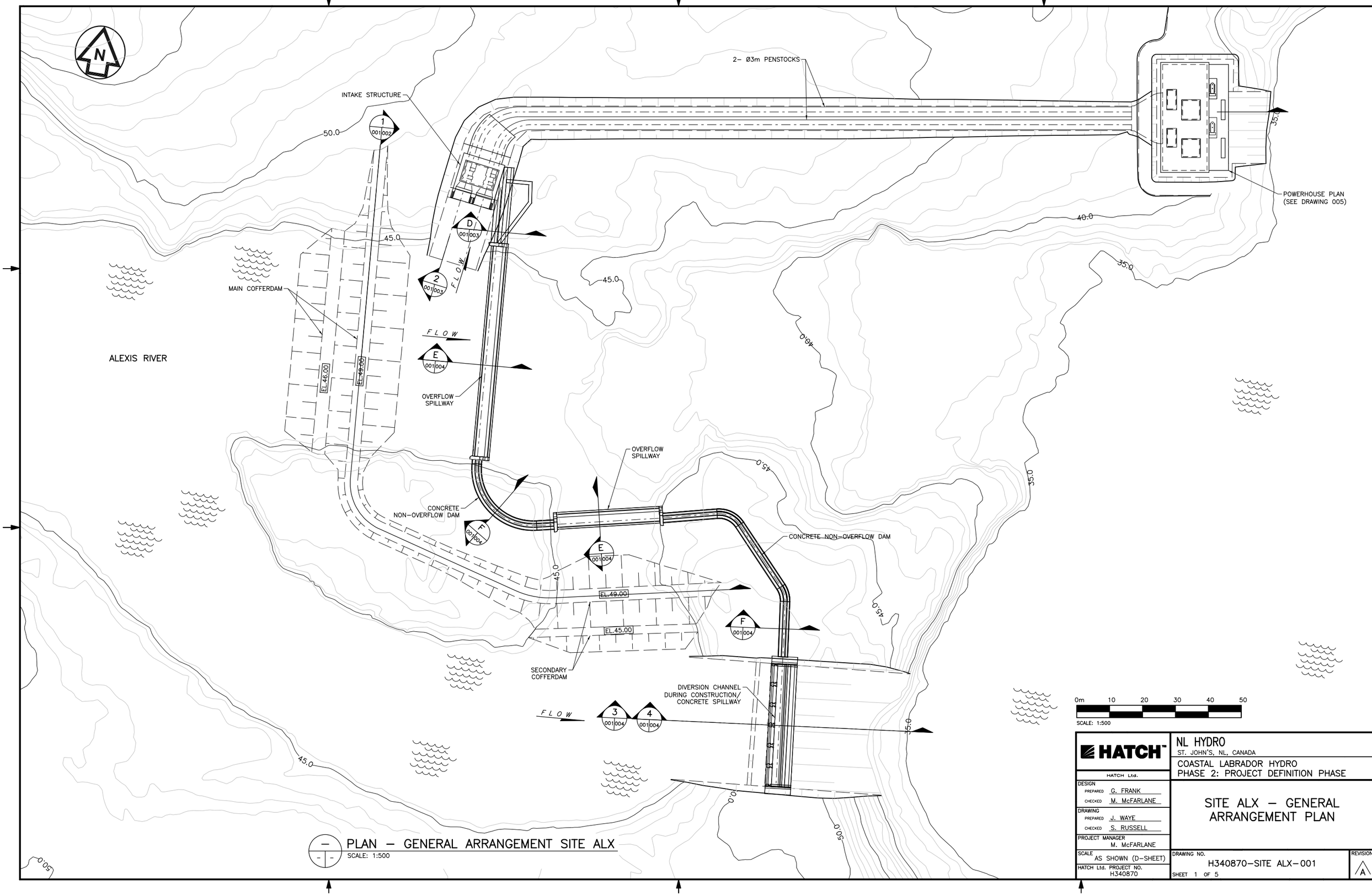
HATCH Ltd.

NL HYDRO
ST, JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

SITE 8C –
POWERHOUSE SECTIONS

DESIGN PREPARED	G. FRANK
DESIGN CHECKED	M. McFARLANE
DRAWING PREPARED	S. RUSSELL
DRAWING CHECKED	J. WAYE
PROJECT MANAGER	M. McFARLANE
SCALE	1:150 (D–SHEET)
HATCH Ltd. PROJECT NO.	H340870
DRAWING NO.	H340870–SITE 8C–005
REVISION	A
SHEET	5 OF 5



PLAN – GENERAL ARRANGEMENT SITE ALX
SCALE: 1:500

0m 10 20 30 40 50
SCALE: 1:500

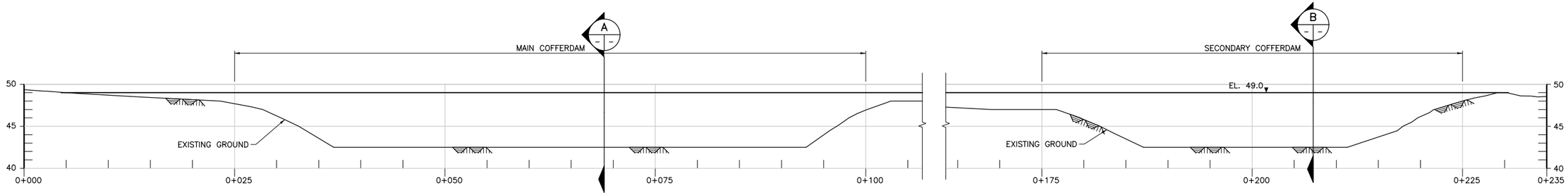
HATCH
HATCH Ltd.

NL HYDRO
ST. JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

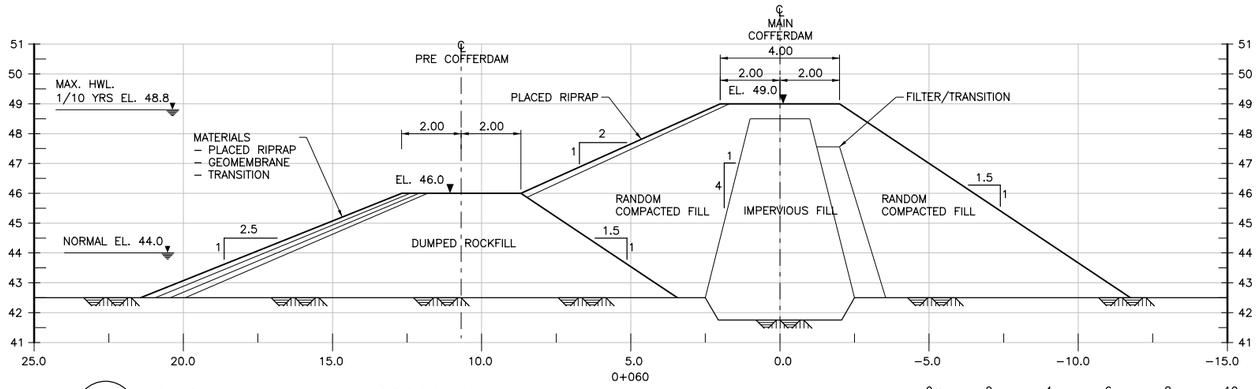
SITE ALX – GENERAL ARRANGEMENT PLAN

DESIGN PREPARED	G. FRANK
DESIGN CHECKED	M. McFARLANE
DRAWING PREPARED	J. WAYE
DRAWING CHECKED	S. RUSSELL
PROJECT MANAGER	M. McFARLANE
SCALE	AS SHOWN (D–SHEET)
HATCH Ltd. PROJECT NO.	H340870
DRAWING NO.	H340870–SITE ALX–001
REVISION	A
SHEET	1 OF 5

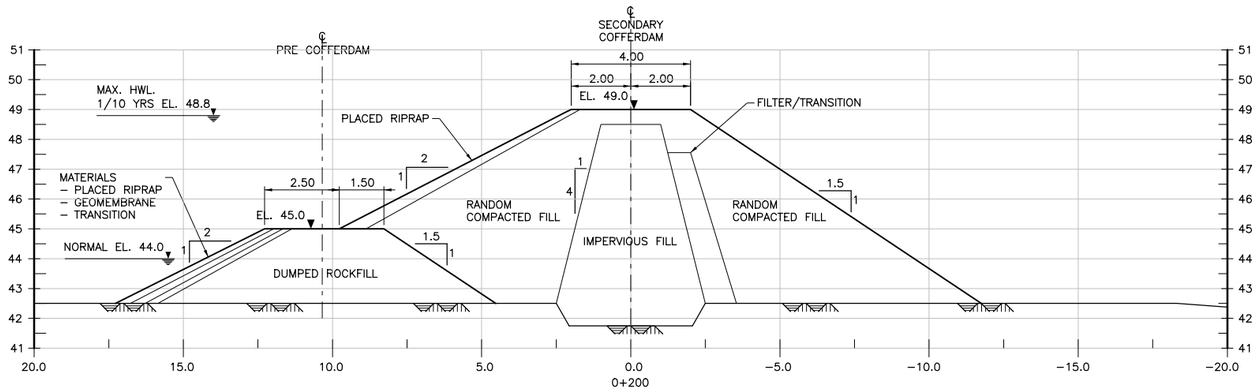


1 002 001 PROFILE – ALONG COFFERDAMS
SCALE: 1:250

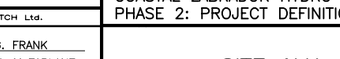




A – SECTION – MAIN COFFERDAM
SCALE: 1:100



B – SECTION – SECONDARY COFFERDAM
SCALE: 1:100



HATCH

HATCH Ltd.

NL HYDRO
ST. JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

DESIGN
PREPARED G. FRANK
CHECKED M. McFARLANE

DRAWING
PREPARED J. WAYE
CHECKED S. RUSSELL

PROJECT MANAGER
M. McFARLANE

SCALE
AS SHOWN (D-SHEET)

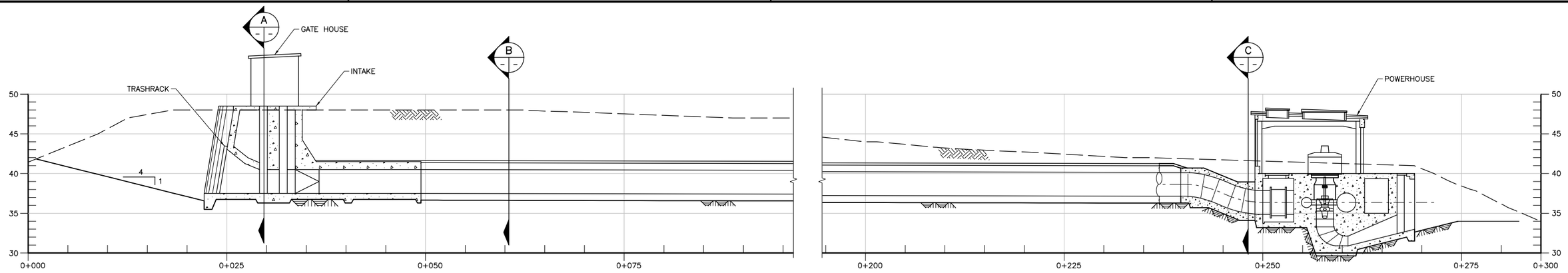
HATCH Ltd. PROJECT NO.
H340870

SITE ALX –
COFFERDAM SECTIONS

DRAWING NO.
H340870-SITE ALX-002

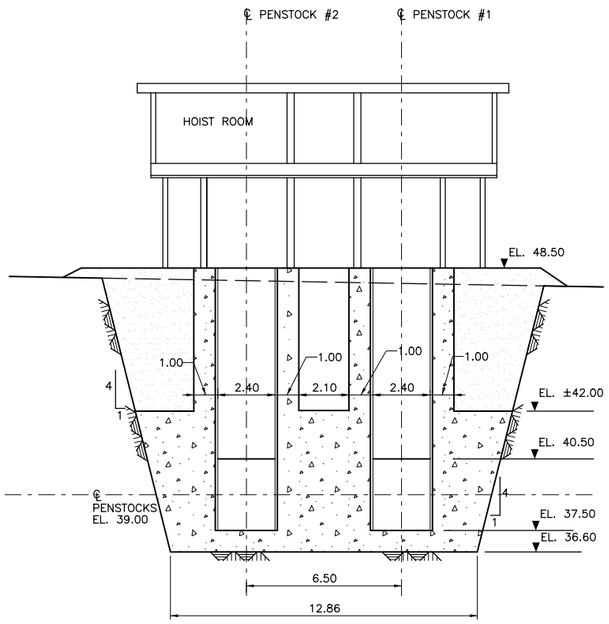
REVISION
A

SHEET 2 OF 5

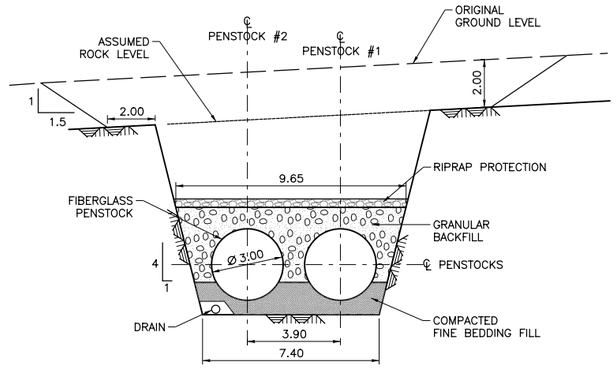


2 SECTION – INTAKE, PENSTOCK, AND POWERHOUSE
003 | 001
SCALE: 1:250

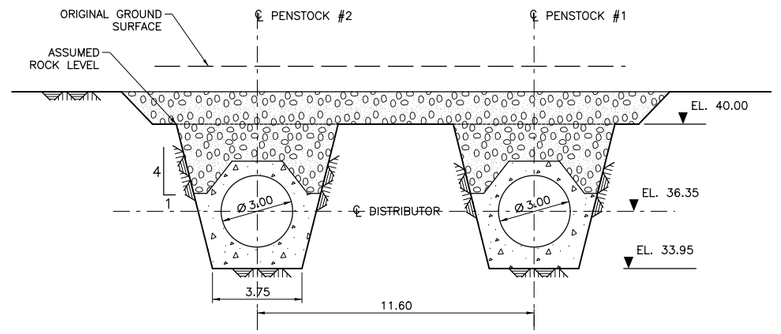
0m 5 10 15 20 25
SCALE: 1:250



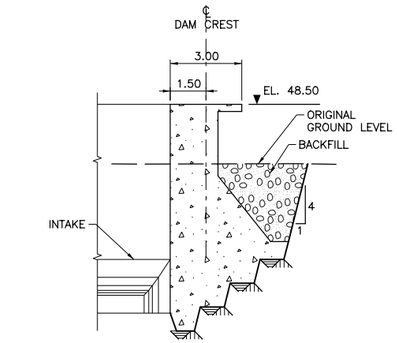
A SECTION – INTAKE
SCALE: 1:125



B SECTION – TYPICAL PENSTOCK
SCALE: 1:125



C SECTION – PENSTOCK AT POWERHOUSE
SCALE: 1:125



D SECTION – TRAINING WALL AT INTAKE
003 | 001
SCALE: 1:125

0m 2.5 5 7.5 10 12.5
SCALE: 1:125

HATCH

HATCH Ltd.

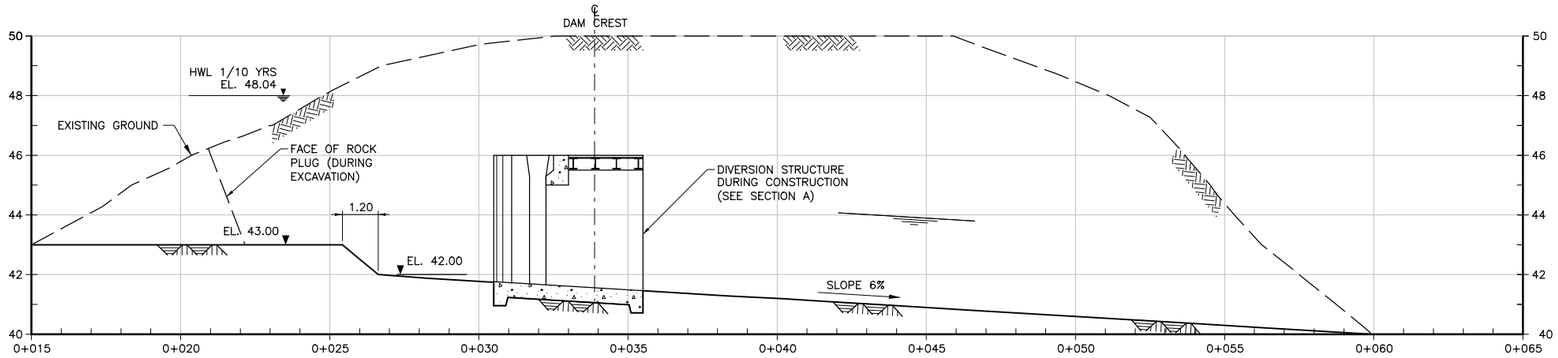
DESIGN
PREPARED G. FRANK
CHECKED M. McFARLANE
DRAWING
PREPARED J. WAYE
CHECKED S. RUSSELL
PROJECT MANAGER M. McFARLANE
SCALE AS SHOWN (D-SHEET)
HATCH Ltd. PROJECT NO. H340870

NL HYDRO
ST. JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

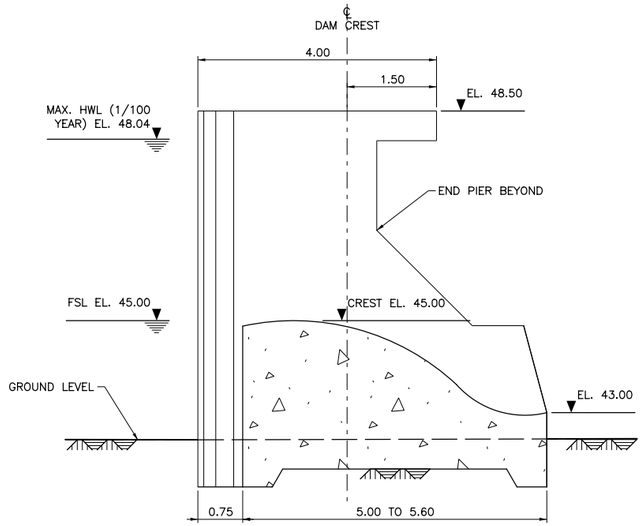
SITE ALX – INTAKE, PENSTOCK SECTIONS

DRAWING NO. H340870-SITE ALX-003
REVISION A
SHEET 3 OF 5

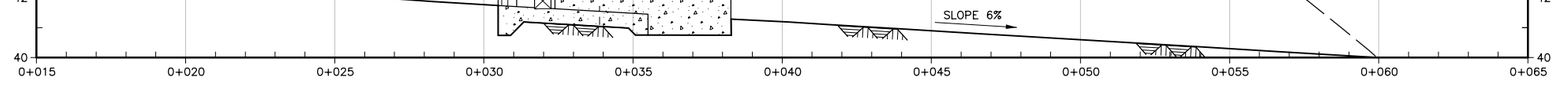


3 | 004 001 SECTION – DIVERSION CHANNEL DURING CONSTRUCTION
SCALE: 1:100

0m 2 4 6 8 10
SCALE: 1:100

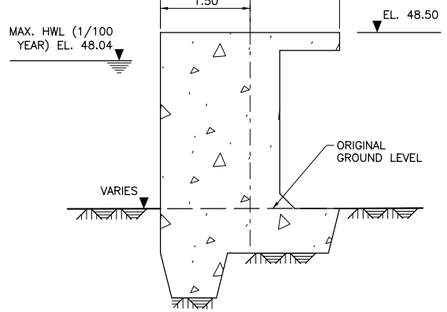


E | 004 001 SECTION – OVERFLOW SPILLWAY
SCALE: 1:50

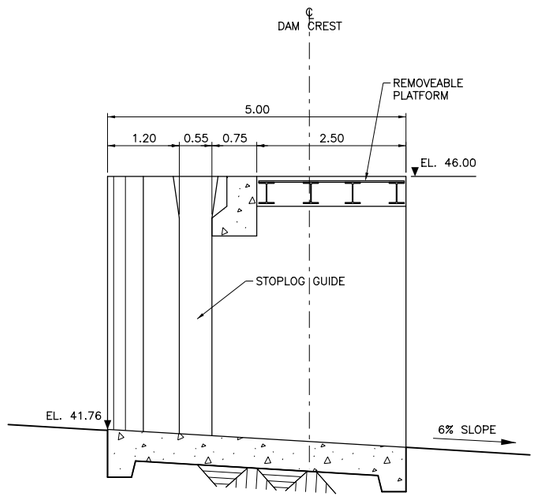


4 | 004 001 SECTION – FINAL OVERFLOW SPILLWAY
SCALE: 1:100

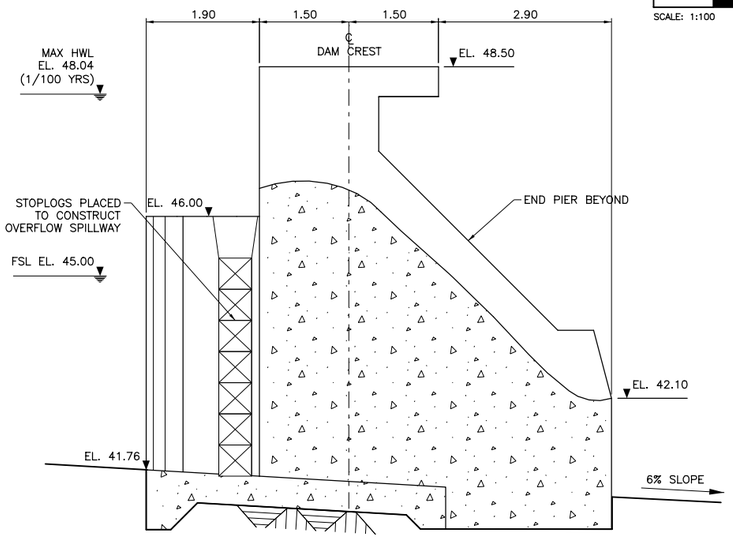
0m 2 4 6 8 10
SCALE: 1:100



F | 004 001 SECTION – NON OVERFLOW DAM
SCALE: 1:50



A | - - SECTION – DIVERSION CHANNEL
SCALE: 1:50



B | - - SECTION – OVERFLOW SPILLWAY
SCALE: 1:50

0m 1 2 3 4 5
SCALE: 1:50

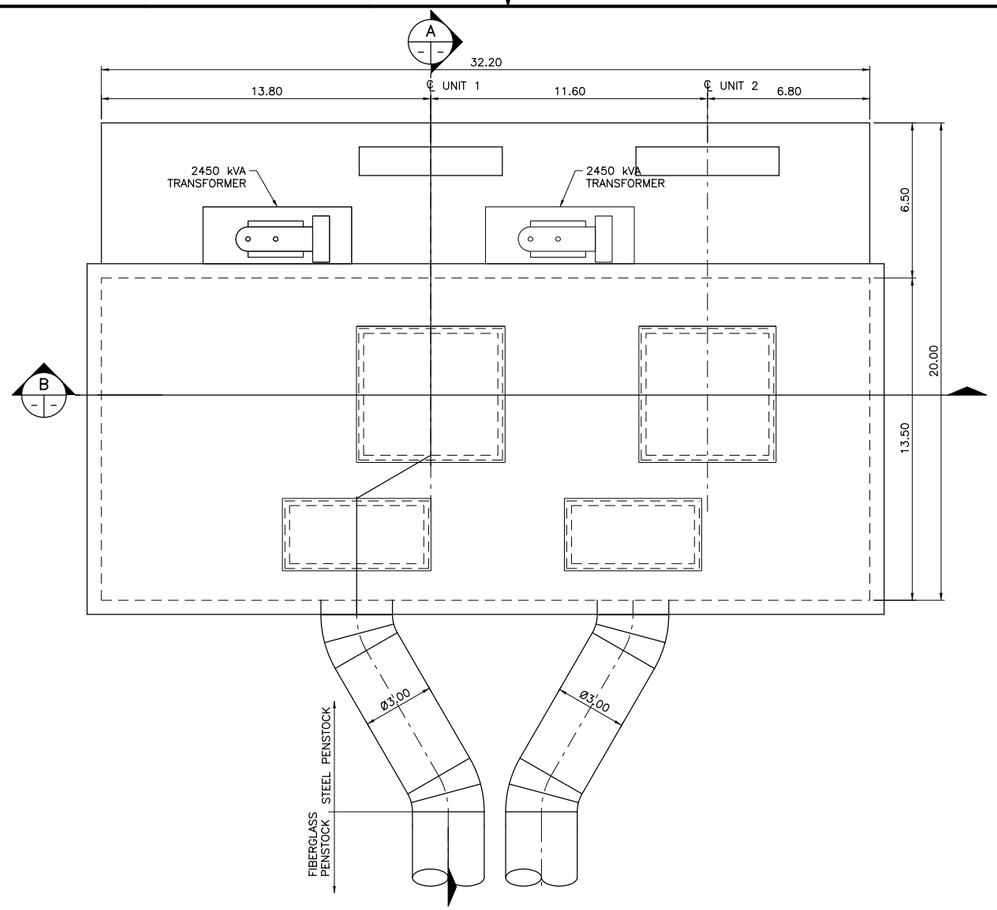
HATCH™
HATCH Ltd.

DESIGN PREPARED	G. FRANK
DESIGN CHECKED	M. McFARLANE
DRAWING PREPARED	J. WAYE
DRAWING CHECKED	S. RUSSELL
PROJECT MANAGER	M. McFARLANE
SCALE	AS SHOWN (D-SHEET)
HATCH Ltd. PROJECT NO.	H340870

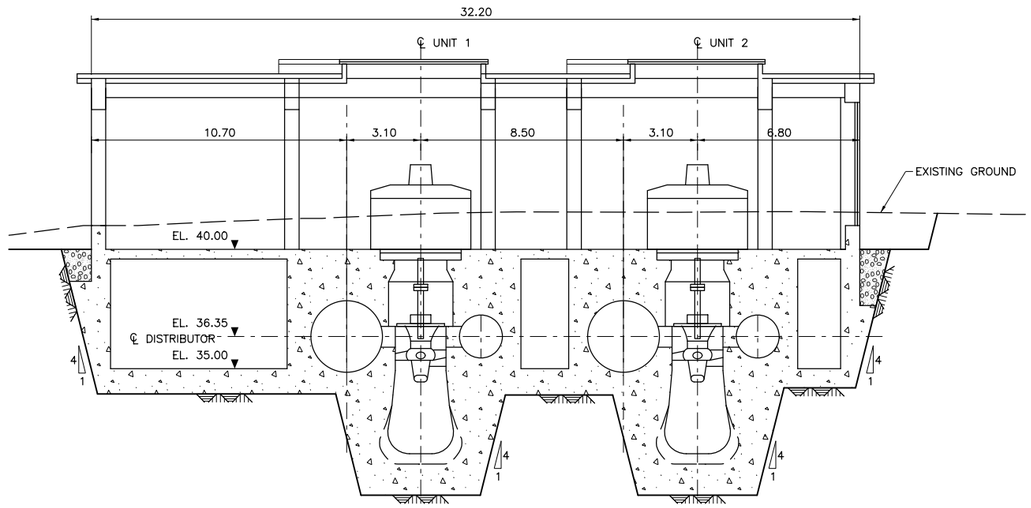
NL HYDRO
ST. JOHN'S, NL, CANADA
COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

SITE ALX – DIVERSION CHANNEL, SPILLWAY AND DAM SECTIONS

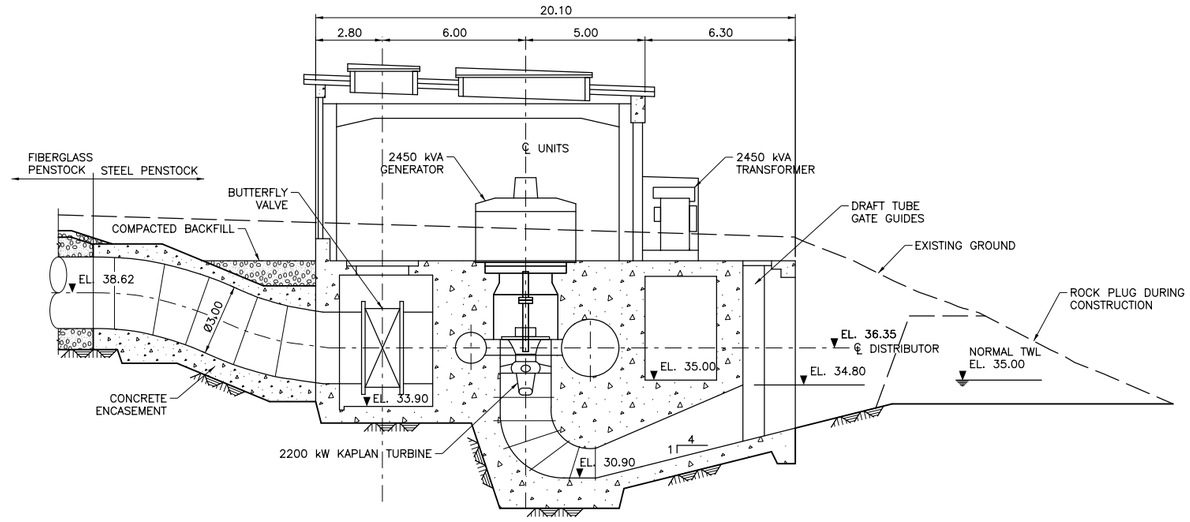
DRAWING NO. H340870-SITE ALX-004
REVISION A
SHEET 4 OF 5



5 005 001 PLAN – POWERHOUSE GENERAL ARRANGEMENT
SCALE: 1:125



B – – SECTION – POWERHOUSE CENTERLINE UNIT 1 & 2
SCALE: 1:125



A – – SECTION – POWERHOUSE CENTERLINE UNIT 2
SCALE: 1:125

0m 2.5 5 7.5 10 12.5
SCALE: 1:125

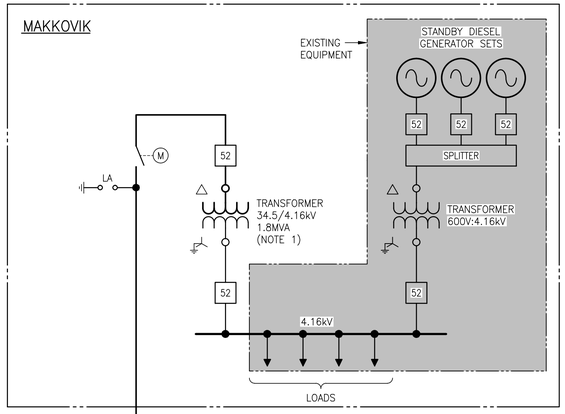
HATCH
HATCH Ltd.

DESIGN
PREPARED G. FRANK
CHECKED M. McFARLANE
DRAWING
PREPARED J. WAYE
CHECKED S. RUSSELL
PROJECT MANAGER M. McFARLANE
SCALE AS SHOWN (D-SHEET)
HATCH Ltd. PROJECT NO. H340870

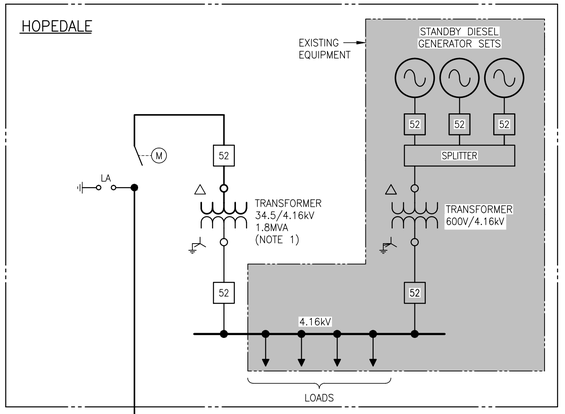
NL HYDRO
ST. JOHN'S, NL, CANADA
COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

SITE ALX – POWERHOUSE PLAN AND SECTIONS

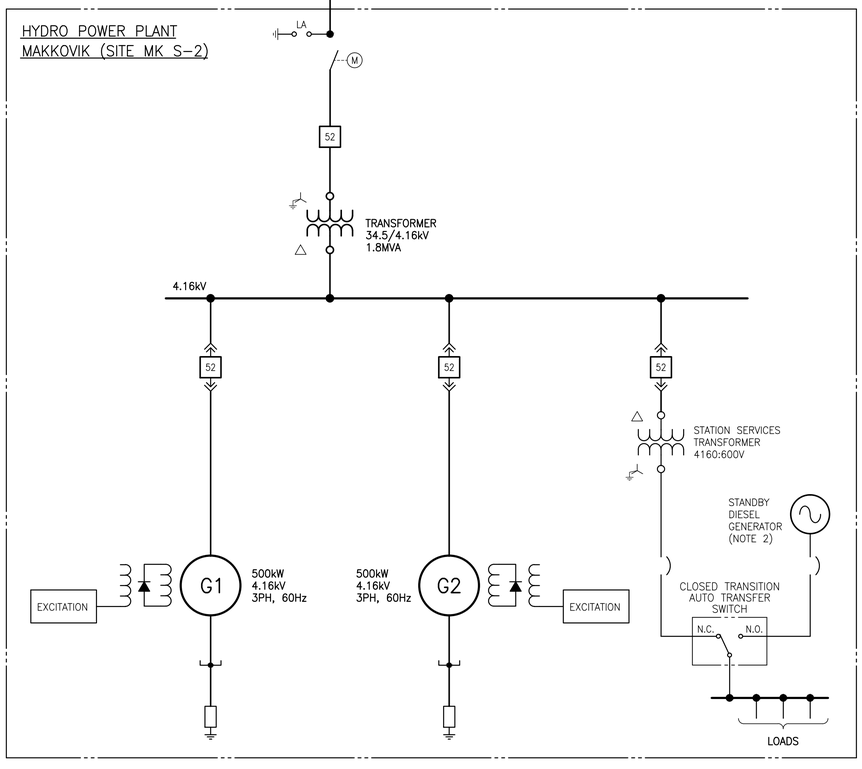
DRAWING NO. H340870-SITE ALX-005
REVISION A
SHEET 5 OF 5

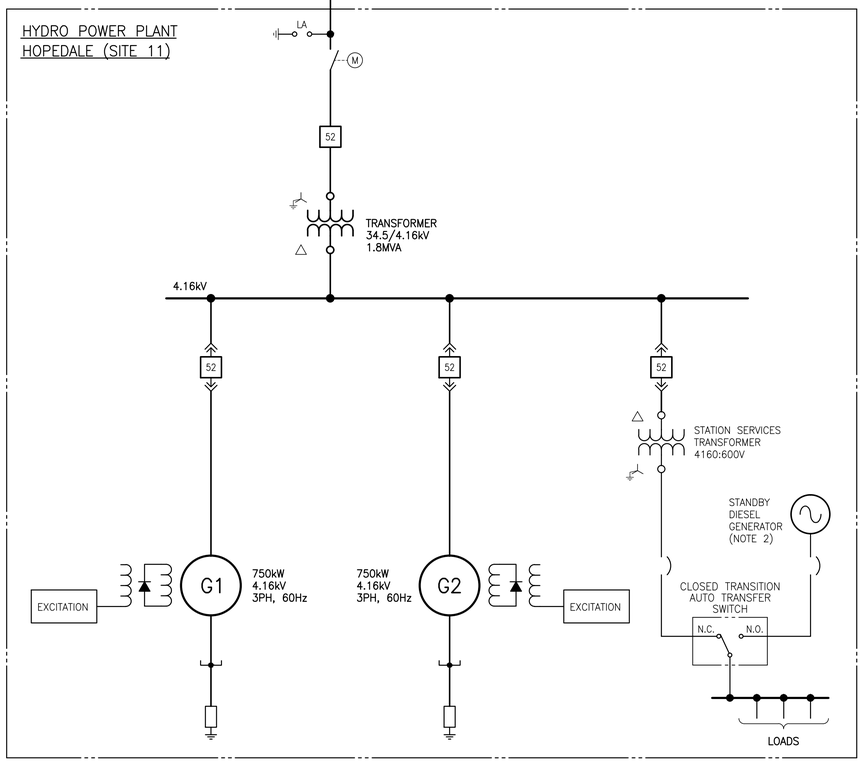


266kcmil
7km
(NOTE 3)



266kcmil
45km
(NOTE 3)





NOTES:

1. DETAILS OF NEW HYDRO SERVICE SUPPLY TO BE DEVELOPED DURING THE NEXT PHASE.
2. SIZING AND TRANSFER ARRANGEMENTS TO BE DETERMINED.
3. ASSUMED VOLTAGE FOR NEW LINE IS 34.5kV.

SYMBOL LEGEND:

- DISCONNECT SWITCH
- LOW VOLTAGE CIRCUIT BREAKER
- 52 — CIRCUIT BREAKER
- 52 — METALCLAD SWITCHGEAR DRAWOUT CIRCUIT BREAKER

HATCH Ltd.

DESIGN PREPARED	J. JOKIC
DESIGN CHECKED	B. LACKENBAUER
DRAWING PREPARED	L. MONTEAN
DRAWING CHECKED	J. WAYE
PROJECT MANAGER	M. McFARLANE
SCALE	NTS (D-SHEET)
HATCH Ltd. PROJECT NO.	H340870

NL HYDRO
ST. JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

HOPEDALE AND MAKKOVIK SITE 11 AND SITE MK S-2 SINGLE LINE DIAGRAM

DRAWING NO. H340870-SITE 11_SITE MK S-2-001
REVISION A
SHEET 1 OF 1

CHARLOTTETOWN

EXISTING EQUIPMENT

STANDBY DIESEL GENERATOR SETS

52 52 52 52

SPLITTER

LA

M

52

TRANSFORMER 34.5:4.16kV 1.8MVA (NOTE 2)

TRANSFORMER 600V:4.16kV

TRANSFORMER 600V:4.16kV

52 52

4.16kV

LOADS

PORT HOPE SIMPSON

EXISTING EQUIPMENT

STANDBY DIESEL GENERATOR SETS

52 52 52

SPLITTER

LA

M

52

TRANSFORMER 34.5:4.16kV 1.8MVA (NOTE 2)

TRANSFORMER 600V:4.16kV

52 52

4.16kV

LOADS

MARY'S HARBOUR

EXISTING EQUIPMENT

STANDBY DIESEL GENERATOR SETS

52 52 52

SPLITTER

LA

M

52

TRANSFORMER 34.5:4.16kV 1.8MVA (NOTE 2)

TRANSFORMER 600V:4.16kV

52 52

4.16kV

LOADS

477kcmil 0km

477kcmil 37km

477kcmil 28km

477kcmil 10.6km

477kcmil 21km (NOTE 3)

(NOTE 4)

(NOTE 4)

477kcmil 13km

(NOTE 4)

(NOTE 4)

(NOTE 4)

477kcmil 18km

477kcmil 10km

HYDRO POWER PLANT
OPTION 1
ALX
(NOTE 1)

LA

M

52

TRANSFORMER 34.5/4.16kV 5MVA

4.16kV

52 52 52

STATION SERVICES TRANSFORMER 4160:600V

STANDBY DIESEL GENERATOR (NOTE 5)

EXCITATION

G1

2.2MW 4.16kV 3PH, 60Hz

2.2MW 4.16kV 3PH, 60Hz

G2

EXCITATION

CLOSED TRANSITION AUTO TRANSFER SWITCH

N.C. N.O.

LOADS

HYDRO POWER PLANT
OPTION 2
SITE 8
(NOTE 1)

LA

M

52

TRANSFORMER 34.5/4.16kV 5MVA

4.16kV

52 52 52

STATION SERVICES TRANSFORMER 4160:600V

STANDBY DIESEL GENERATOR (NOTE 5)

EXCITATION

G1

2.2MW 4.16kV 3PH, 60Hz

2.2MW 4.16kV 3PH, 60Hz

G2

EXCITATION

CLOSED TRANSITION AUTO TRANSFER SWITCH

N.C. N.O.

LOADS

NOTES:

1. THIS DRAWING SHOWS TWO OPTIONS (SIT 8 OR SITE ALX) FOR THE NEW TWO UNIT 1. (2.2MW EACH) POWERHOUSE. ONLY ONE OF THESE TWO SITES WOULD BE CHOSEN.
2. DETAILS OF NEW HYDRO SERVICE SUPPLY TO BE DEVELOPED DURING THE NEXT PHASE.
3. ASSUMED VOLTAGE FOR NEW LINE IS 34.5kV.
4. SECTIONALIZER SWITCHES TO BE LOCATED BASED ON FINAL SITE DETERMINATION.
5. SIZING AND TRANSFER ARRANGEMENTS TO BE DETERMINED.

SYMBOL LEGEND:

DISCONNECT SWITCH

LOW VOLTAGE CIRCUIT BREAKER

52 CIRCUIT BREAKER

52 METALCLAD SWITCHGEAR DRAWOUT CIRCUIT BREAKER

HATCH™
HATCH Ltd.

DESIGN PREPARED	J. JOKIC
DESIGN CHECKED	B. LACKENBAUER
DRAWING PREPARED	L. MONTEAN
DRAWING CHECKED	J. WAYE
PROJECT MANAGER	M. McFARLANE
SCALE	NTS (D-SHEET)
HATCH Ltd. PROJECT NO.	H340870

NL HYDRO
ST. JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

CHARLOTTETOWN, PORT HOPE SIMPSON & MARY'S HARBOUR SITE 8 OR SITE ALX SINGLE LINE DIAGRAM

DRAWING NO. H340870-SITE 8_ALX-001

REVISION A

SHEET 1 OF 1

Appendix E

Power and Energy Estimates

Safety • Quality • Sustainability • Innovation

Table E-1 **Coastal Labrador Hydro**

Estimated Monthly Energy Site 11 - Without Riparian Flow **Phase 2**

Calendar Year	Monthly Energy Generated (Run-of-River) (MWh)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1979	1,072	968	1,060	782	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1980	1,072	1,003	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1981	1,072	968	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1982	1,072	968	1,037	927	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1983	1,072	968	911	784	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1984	1,072	1,001	927	700	1,044	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1985	1,072	968	961	729	738	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1986	1,072	968	936	789	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1987	1,070	782	618	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1988	1,072	962	976	831	1,017	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1989	1,071	817	576	552	1,028	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1990	1,072	968	1,072	1,001	1,056	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1991	1,072	962	758	476	907	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1992	1,072	967	831	610	825	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1993	932	454	455	421	846	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1994	1,070	862	822	713	1,041	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1995	1,072	968	943	716	1,069	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1996	1,072	1,003	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1997	1,072	968	853	552	978	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1998	1,072	968	1,063	1,020	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1999	1,072	968	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2000	1,072	1,003	1,036	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2001	1,072	949	826	592	961	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2002	1,072	968	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2003	1,072	968	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2004	1,072	1,003	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2005	1,072	968	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2006	1,072	968	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2007	1,072	968	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2008	1,072	995	881	839	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2009	1,072	968	1,066	969	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2010	1,072	968	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
Mean:	1,067	943	950	859	1,030	1,037	1,072	1,072	1,037	1,072	1,037	1,072
Max:	1,072	1,003	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
Min:	932	454	455	421	738	1,037	1,072	1,072	1,037	1,072	1,037	1,072

Table E-2 **Coastal Labrador Hydro**

Estimated Monthly Energy Site MK S-2 - Without Riparian Flow **Phase 2**

Calendar Year	Monthly Energy Generated (Run-of-River) (MWh)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1979	70	0	0	3	694	688	711	709	688	711	345	133
1980	40	0	0	3	497	688	711	666	608	637	400	160
1981	89	0	0	3	450	688	711	711	605	711	381	125
1982	6	0	0	0	367	688	706	664	688	490	202	103
1983	0	0	0	109	711	688	711	409	510	708	296	96
1984	0	0	0	0	460	688	711	522	600	603	161	93
1985	0	0	0	0	100	688	711	500	551	480	207	93
1986	0	0	0	0	490	688	711	650	505	509	139	23
1987	0	0	0	478	704	679	591	586	548	564	256	162
1988	0	0	0	0	404	688	701	399	442	647	187	13
1989	0	0	0	0	394	688	568	549	591	710	409	143
1990	26	0	0	0	243	688	710	363	455	685	197	110
1991	0	0	0	0	109	688	711	635	688	705	418	83
1992	0	0	0	0	180	688	642	625	637	678	262	20
1993	0	0	0	0	331	688	472	244	616	601	145	6
1994	0	0	0	0	324	688	631	388	687	615	401	126
1995	0	0	0	0	514	688	681	221	158	456	282	88
1996	0	0	0	43	711	688	710	409	176	391	499	157
1997	31	0	0	0	154	688	711	618	345	699	427	269
1998	86	0	0	0	591	688	566	569	416	696	515	142
1999	37	0	0	0	479	688	711	711	688	685	256	120
2000	0	0	0	3	275	688	700	552	409	576	190	77
2001	6	0	0	0	457	688	710	613	673	669	580	210
2002	127	6	0	0	51	688	711	681	544	605	438	146
2003	72	0	0	0	443	688	711	334	192	560	434	162
2004	64	0	0	0	386	688	702	705	609	671	240	162
2005	37	0	0	18	594	688	414	508	668	711	452	248
2006	123	22	0	59	675	688	704	711	450	414	381	153
2007	86	0	0	0	160	688	695	245	615	686	384	139
2008	6	0	0	0	674	670	699	649	402	391	311	92
2009	0	0	0	0	253	688	673	485	222	172	121	80
2010	16	59	28	38	586	688	711	636	219	220	211	148
Mean:	29	3	1	24	421	687	672	540	506	583	316	121
Max:	127	59	28	478	711	688	711	711	688	711	580	269
Min:	0	0	0	0	51	670	414	221	158	172	121	6

Table E-3 **Coastal Labrador Hydro**

Estimated Monthly Energy Site 8c - Without Riparian Flow **Phase 2**

Calendar Year	Monthly Energy Generated (Run-of-River) (MWh)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1978	1,499	975	909	1,450	3,144	3,042	3,144	2,898	3,042	3,144	2,694	1,912
1979	3,097	2,737	2,711	2,938	3,144	3,035	3,129	3,069	3,042	3,144	2,920	1,812
1980	1,168	804	764	1,848	3,144	3,042	3,144	2,990	3,039	3,144	3,042	3,144
1981	2,676	1,641	1,448	1,552	3,144	3,042	3,144	3,133	2,804	3,144	3,016	1,840
1982	1,167	851	850	925	3,141	3,042	3,144	3,144	3,042	3,019	3,028	2,809
1983	1,907	1,403	1,222	1,827	3,144	3,042	3,132	3,144	3,042	3,144	3,042	2,351
1984	1,454	944	1,039	951	3,120	3,042	3,144	2,368	2,290	2,138	1,910	1,267
1985	806	591	588	585	1,956	3,042	3,144	2,961	2,978	3,144	2,933	1,706
1986	1,036	1,080	784	2,521	3,144	3,039	2,905	2,420	2,765	2,944	1,495	997
1987	791	593	650	1,927	3,144	3,042	2,707	1,979	2,312	3,144	3,000	3,144
1988	2,407	1,333	1,312	1,604	3,144	3,042	3,144	2,851	2,857	3,144	3,042	2,209
1989	1,115	550	510	1,308	3,144	2,539	2,847	3,144	3,042	3,144	3,042	2,912
1990	1,624	890	690	1,175	3,122	3,042	3,144	3,036	3,023	2,772	3,011	3,144
1991	2,453	1,505	1,287	1,156	3,044	3,042	3,144	3,027	3,033	3,144	3,042	2,696
1992	1,677	1,101	916	1,386	3,124	3,042	3,143	3,069	2,835	3,144	2,768	1,631
1993	1,013	663	568	576	2,873	3,042	3,144	3,077	2,939	3,144	2,765	1,707
1994	1,097	728	608	524	2,693	3,042	3,144	3,144	3,042	3,144	3,042	2,567
1995	1,364	784	657	606	2,902	3,042	3,144	2,800	3,009	3,144	3,042	2,970
1996	2,615	1,593	2,036	2,647	3,144	3,042	3,144	2,847	2,128	2,931	3,013	1,758
1997	1,036	734	670	761	3,098	3,042	3,144	3,144	2,951	3,144	3,042	2,958
1998	1,853	1,220	2,749	2,694	3,144	3,042	3,086	2,853	3,042	3,144	3,042	2,537
1999	1,654	1,590	1,525	2,391	3,144	3,037	3,102	3,111	2,559	3,144	3,042	2,862
2000	1,539	1,028	1,706	1,946	3,144	3,042	3,144	2,050	1,626	2,656	3,042	2,542
2001	1,491	804	1,521	1,548	3,144	3,042	3,137	2,286	2,852	3,120	3,042	3,084
2002	2,656	1,014	1,100	1,513	3,118	3,042	3,110	3,061	3,019	3,118	2,984	2,092
2003	1,513	1,010	931	1,692	3,144	3,042	3,144	2,975	2,460	2,549	3,042	2,644
2004	1,670	1,170	1,031	2,230	3,144	3,042	2,478	2,747	1,640	2,339	1,677	1,414
2005	876	721	1,288	2,359	3,144	2,718	2,888	3,141	2,898	3,002	3,042	2,693
2006	1,053	675	1,109	2,734	3,144	3,042	1,840	1,597	1,477	2,833	3,042	2,817
2007	1,606	850	703	1,350	3,143	3,042	3,140	3,144	3,042	3,134	3,042	2,982
2008	2,058	1,476	1,231	2,328	3,144	3,042	2,748	2,561	2,804	3,144	3,042	2,767
2009	1,746	1,196	1,081	1,723	3,144	3,033	2,770	2,924	2,938	2,912	2,770	2,461
2010	2,343	2,306	2,124	2,846	3,144	3,042	3,144	3,035	2,081	3,104	3,042	3,144
Mean:	1,638	1,108	1,161	1,685	3,071	3,017	3,018	2,840	2,717	3,005	2,871	2,411
Max:	3,097	2,737	2,749	2,938	3,144	3,042	3,144	3,144	3,042	3,144	3,042	3,144
Min:	791	550	510	524	1,956	2,539	1,840	1,597	1,477	2,138	1,495	997

Table E-4 **Coastal Labrador Hydro**

Estimated Monthly Energy Site ALX - Without Riparian Flow **Phase 2**

Calendar Year	Monthly Energy Generated (Run-of-River) (MWh)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1978	45	0	0	362	3,074	3,042	2,205	1,865	2,498	2,872	1,202	590
1979	1,437	1,332	1,230	1,663	3,076	1,900	2,046	2,267	2,717	2,810	1,727	427
1980	0	0	0	963	3,144	3,042	2,714	2,112	2,178	3,073	2,796	1,884
1981	1,112	454	0	401	3,144	3,042	2,533	2,362	1,794	2,818	1,978	450
1982	0	0	0	29	2,994	2,996	2,909	2,345	1,902	1,528	2,063	1,238
1983	693	0	0	1,054	3,079	2,811	2,356	3,126	2,341	2,576	2,427	980
1984	0	0	0	0	3,033	2,942	2,532	954	835	799	559	0
1985	0	0	0	0	1,097	3,030	2,722	1,813	2,085	2,510	1,961	318
1986	0	0	0	1,868	3,095	2,338	1,947	979	1,259	1,533	172	0
1987	0	0	0	1,072	3,144	2,412	1,177	542	983	2,494	2,125	2,098
1988	998	0	48	285	3,116	2,981	2,750	1,409	1,928	2,942	1,857	778
1989	0	0	0	239	3,129	1,774	1,733	2,992	2,839	2,685	2,198	1,244
1990	256	0	0	78	2,833	3,042	2,841	1,929	1,784	1,216	1,974	2,118
1991	1,012	189	0	23	2,681	3,042	2,974	1,921	1,855	2,830	1,992	1,165
1992	247	0	0	121	2,869	2,764	2,207	2,225	1,794	2,448	1,427	226
1993	0	0	0	0	2,345	2,696	2,994	1,942	1,847	2,508	1,271	329
1994	0	0	0	0	2,269	2,923	2,509	2,222	2,171	2,396	2,723	1,126
1995	23	0	0	0	2,521	2,919	2,731	1,465	1,863	1,864	2,575	1,332
1996	1,088	244	528	1,488	3,144	2,822	3,030	1,621	746	2,086	2,342	384
1997	0	0	0	24	2,799	3,042	3,124	2,294	1,788	2,450	2,330	1,652
1998	475	0	1,244	1,684	3,126	2,644	2,018	1,773	2,745	2,941	2,311	1,051
1999	218	386	118	945	3,049	2,379	1,912	2,290	1,502	2,352	2,083	1,488
2000	146	0	315	605	2,964	3,042	2,975	543	211	1,423	2,316	1,060
2001	171	0	237	509	2,917	2,760	2,593	963	1,778	2,086	2,704	1,797
2002	1,263	0	0	393	2,524	2,723	2,176	2,410	2,273	1,962	1,656	793
2003	22	0	0	627	3,144	2,791	2,625	2,321	1,252	1,584	2,103	1,141
2004	264	0	0	777	3,144	3,005	1,118	1,350	312	1,452	361	181
2005	0	0	118	1,318	3,144	1,613	1,884	2,405	1,502	2,147	2,106	1,497
2006	0	0	181	1,797	3,144	2,190	572	261	457	1,670	2,485	1,284
2007	252	0	0	255	2,936	2,693	2,531	2,892	2,655	2,204	2,544	1,353
2008	820	0	0	1,350	3,144	2,922	1,419	1,265	1,951	2,232	1,822	1,201
2009	348	0	0	755	3,144	2,553	1,622	1,708	2,014	1,811	1,308	1,016
2010	886	1,230	668	2,566	3,144	3,042	2,697	1,951	721	3,034	3,004	2,995
Mean:	357	116	142	705	2,912	2,725	2,308	1,834	1,715	2,222	1,955	1,067
Max:	1,437	1,332	1,244	2,566	3,144	3,042	3,124	3,126	2,839	3,073	3,004	2,995
Min:	0	0	0	0	1,097	1,613	572	261	211	799	172	0

Table E-5 **Coastal Labrador Hydro**

Estimated Annual Energy for Final Potential Sites - Without Riparian Flow **Phase 2**

Calendar Year	Year Index	Annual Energy Generated (Run-of-River) (MWh)			
		Site 11	Site MK S-2	Site 8	Site ALX
1978	1	-	-	27,854	17,756
1979	2	12,352	4,751	34,778	22,631
1980	3	12,654	4,410	29,274	21,907
1981	4	12,619	4,472	30,584	20,088
1982	5	12,474	3,914	28,163	18,004
1983	6	12,205	4,236	30,401	21,443
1984	7	12,143	3,837	23,667	11,653
1985	8	11,866	3,329	24,436	15,537
1986	9	12,235	3,714	25,130	13,191
1987	10	11,978	4,569	26,434	16,046
1988	11	12,257	3,480	30,090	19,091
1989	12	11,443	4,051	27,297	18,832
1990	13	12,567	3,478	28,673	18,072
1991	14	11,574	4,035	30,575	19,685
1992	15	11,704	3,731	27,836	16,329
1993	16	10,506	3,102	25,512	15,930
1994	17	11,908	3,860	26,774	18,339
1995	18	12,166	3,087	27,465	17,293
1996	19	12,654	3,783	30,899	19,524
1997	20	11,821	3,941	27,725	19,504
1998	21	12,594	4,269	32,407	22,013
1999	22	12,619	4,372	31,163	18,723
2000	23	12,618	3,469	27,465	15,601
2001	24	11,799	4,606	29,069	18,514
2002	25	12,619	3,995	29,827	18,173
2003	26	12,619	3,595	28,147	17,611
2004	27	12,654	4,226	24,583	11,964
2005	28	12,619	4,337	28,771	17,735
2006	29	12,619	4,380	25,364	14,040
2007	30	12,619	3,695	29,179	20,314
2008	31	12,257	3,893	30,348	18,126
2009	32	12,546	2,693	28,697	16,278
2010	33	12,619	3,559	33,355	25,937
Mean:		12,248	3,902	28,544	18,057
Max:		12,654	4,751	34,778	25,937
Min:		10,506	2,693	23,667	11,653
Coefficent of Variation (%):		4%	12%	9%	17%

Table E-6 **Coastal Labrador Hydro**

Estimated Monthly Energy Site 11 - With Riparian Flow **Phase 2**

Calendar Year	Monthly Energy Generated (Run-of-River) (MWh)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1979	1,072	968	1,048	743	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1980	1,072	1,003	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1981	1,072	968	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1982	1,072	968	1,009	896	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1983	1,072	964	869	753	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1984	1,072	994	884	657	1,019	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1985	1,072	967	919	687	590	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1986	1,072	964	894	753	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1987	1,055	739	576	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1988	1,072	930	937	791	969	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1989	1,055	774	531	512	983	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1990	1,072	968	1,072	969	995	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1991	1,072	953	714	436	817	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1992	1,072	941	788	566	718	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1993	861	410	410	379	718	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1994	1,046	820	778	672	986	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1995	1,072	967	901	673	1,062	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1996	1,072	1,003	1,065	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1997	1,072	966	809	510	890	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1998	1,072	968	1,053	1,012	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
1999	1,072	968	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2000	1,072	1,003	1,020	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2001	1,072	930	782	548	900	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2002	1,072	968	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2003	1,072	968	1,072	1,035	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2004	1,072	1,003	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2005	1,072	968	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2006	1,072	968	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2007	1,072	968	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2008	1,072	982	838	804	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2009	1,072	968	1,051	939	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
2010	1,072	968	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
Mean:	1,063	934	927	837	1,003	1,037	1,072	1,072	1,037	1,072	1,037	1,072
Max:	1,072	1,003	1,072	1,037	1,072	1,037	1,072	1,072	1,037	1,072	1,037	1,072
Min:	861	410	410	379	590	1,037	1,072	1,072	1,037	1,072	1,037	1,072

Table E-7 **Coastal Labrador Hydro**

Estimated Monthly Energy Site MK S-2 - With Riparian Flow **Phase 2**

Calendar Year	Monthly Energy Generated (Run-of-River) (MWh)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1979	62	0	0	3	694	688	711	708	688	711	332	128
1980	30	0	0	3	491	688	711	659	597	624	386	155
1981	74	0	0	3	442	688	711	711	594	711	369	117
1982	0	0	0	0	360	688	701	649	688	471	191	87
1983	0	0	0	109	711	688	711	384	500	707	284	82
1984	0	0	0	0	458	688	711	505	593	589	151	80
1985	0	0	0	0	99	688	711	479	536	459	194	80
1986	0	0	0	0	488	688	711	640	486	488	129	13
1987	0	0	0	478	703	661	553	567	529	544	243	157
1988	0	0	0	0	403	688	691	374	428	635	176	6
1989	0	0	0	0	392	688	538	530	574	709	394	138
1990	19	0	0	0	240	688	709	336	436	678	185	96
1991	0	0	0	0	104	688	711	620	688	703	407	73
1992	0	0	0	0	176	687	627	611	630	666	251	16
1993	0	0	0	0	330	687	433	218	601	584	127	0
1994	0	0	0	0	323	688	613	369	685	596	388	112
1995	0	0	0	0	508	688	663	200	144	436	269	72
1996	0	0	0	43	711	688	709	384	162	369	490	152
1997	27	0	0	0	149	688	711	606	327	693	412	261
1998	77	0	0	0	587	688	534	551	398	691	505	137
1999	29	0	0	0	477	688	711	711	688	680	243	106
2000	0	0	0	0	268	688	693	532	389	559	178	61
2001	3	0	0	0	456	688	707	599	669	662	572	204
2002	120	3	0	0	46	688	711	667	526	594	425	141
2003	61	0	0	0	437	688	711	314	171	538	422	157
2004	56	0	0	0	380	688	696	703	599	657	227	154
2005	30	0	0	18	592	688	374	497	659	711	438	242
2006	120	16	0	59	673	688	699	711	434	393	365	148
2007	78	0	0	0	158	688	684	221	610	678	369	133
2008	3	0	0	0	674	642	686	633	380	371	298	79
2009	0	0	0	0	246	688	656	459	205	157	111	52
2010	9	59	28	38	579	688	711	627	200	202	194	142
Mean:	25	2	1	24	417	685	663	524	494	571	304	112
Max:	120	59	28	478	711	688	711	711	688	711	572	261
Min:	0	0	0	0	46	642	374	200	144	157	111	0

Table E-8 **Coastal Labrador Hydro**

Estimated Monthly Energy Site 8c - With Riparian Flow **Phase 2**

Calendar Year	Monthly Energy Generated (Run-of-River) (MWh)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1978	1,427	924	857	1,399	3,144	3,042	3,143	2,835	3,042	3,144	2,591	1,832
1979	3,075	2,717	2,676	2,919	3,144	3,005	3,107	3,040	3,042	3,144	2,875	1,725
1980	1,092	745	711	1,814	3,144	3,042	3,144	2,933	3,028	3,144	3,042	3,144
1981	2,615	1,593	1,396	1,509	3,144	3,042	3,144	3,122	2,733	3,144	2,994	1,745
1982	1,093	796	797	872	3,095	3,042	3,144	3,144	3,042	2,958	3,007	2,752
1983	1,829	1,352	1,171	1,798	3,144	3,042	3,118	3,144	3,042	3,144	3,042	2,269
1984	1,380	890	988	899	3,086	3,042	3,144	2,269	2,179	1,878	1,756	1,172
1985	724	532	534	529	1,185	3,042	3,144	2,900	2,943	3,144	2,896	1,609
1986	959	1,028	731	2,506	3,144	2,993	2,807	2,303	2,674	2,853	1,353	901
1987	710	534	596	1,895	3,144	3,011	2,570	1,841	2,179	3,144	2,979	3,144
1988	2,338	1,280	1,264	1,560	3,144	3,042	3,144	2,761	2,801	3,144	3,040	2,119
1989	1,037	491	455	1,264	3,144	2,362	2,759	3,144	3,042	3,144	3,042	2,855
1990	1,550	836	636	1,124	3,031	3,042	3,144	3,004	2,999	2,637	3,002	3,144
1991	2,371	1,462	1,234	1,110	2,875	3,042	3,144	2,973	3,018	3,144	3,042	2,618
1992	1,610	1,047	864	1,339	3,045	3,042	3,132	3,048	2,771	3,144	2,691	1,536
1993	937	605	513	520	2,597	3,042	3,144	3,048	2,910	3,144	2,687	1,616
1994	1,021	671	553	467	2,409	3,042	3,144	3,144	3,042	3,139	3,042	2,498
1995	1,292	728	603	550	2,677	3,042	3,144	2,730	2,987	3,126	3,042	2,921
1996	2,541	1,551	1,998	2,615	3,144	3,042	3,144	2,776	1,994	2,864	2,994	1,668
1997	960	677	615	707	2,978	3,042	3,144	3,143	2,912	3,144	3,042	2,925
1998	1,781	1,164	2,719	2,681	3,144	3,042	3,057	2,805	3,042	3,144	3,042	2,443
1999	1,591	1,540	1,480	2,349	3,138	3,016	3,075	3,096	2,427	3,144	3,042	2,818
2000	1,469	975	1,657	1,910	3,144	3,042	3,144	1,919	1,458	2,547	3,042	2,447
2001	1,424	748	1,474	1,507	3,139	3,042	3,130	2,142	2,804	3,091	3,042	3,062
2002	2,615	960	1,049	1,470	2,933	3,042	3,080	3,036	2,999	3,050	2,941	2,001
2003	1,441	959	880	1,653	3,144	3,042	3,144	2,928	2,379	2,439	3,038	2,566
2004	1,609	1,114	984	2,185	3,144	3,042	2,356	2,660	1,477	2,236	1,528	1,319
2005	795	664	1,242	2,328	3,144	2,522	2,816	3,133	2,828	2,936	3,041	2,651
2006	975	618	1,044	2,717	3,144	3,042	1,675	1,449	1,340	2,704	3,042	2,765
2007	1,529	796	649	1,295	3,079	3,042	3,133	3,144	3,042	3,114	3,042	2,938
2008	1,984	1,426	1,179	2,303	3,144	3,042	2,646	2,462	2,758	3,139	3,042	2,708
2009	1,676	1,140	1,034	1,685	3,144	2,990	2,655	2,852	2,902	2,826	2,681	2,367
2010	2,278	2,285	2,086	2,841	3,144	3,042	3,144	3,010	1,927	3,100	3,042	3,144
Mean:	1,568	1,056	1,111	1,646	3,000	3,000	2,987	2,786	2,659	2,964	2,840	2,346
Max:	3,075	2,717	2,719	2,919	3,144	3,042	3,144	3,144	3,042	3,144	3,042	3,144
Min:	710	491	455	467	1,185	2,362	1,675	1,449	1,340	1,878	1,353	901

Table E-9 **Coastal Labrador Hydro**

Estimated Monthly Energy Site ALX - With Riparian Flow **Phase 2**

Calendar Year	Monthly Energy Generated (Run-of-River) (MWh)											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1978	0	0	0	355	2,998	3,042	2,136	1,805	2,451	2,838	1,137	471
1979	1,403	1,308	1,209	1,644	2,996	1,730	1,965	2,215	2,695	2,768	1,665	338
1980	0	0	0	957	3,144	3,042	2,672	2,065	2,118	3,053	2,770	1,842
1981	1,076	371	0	395	3,144	3,042	2,476	2,315	1,740	2,778	1,930	383
1982	0	0	0	29	2,894	2,979	2,881	2,290	1,838	1,438	2,019	1,194
1983	551	0	0	1,052	2,979	2,754	2,299	3,119	2,287	2,520	2,387	869
1984	0	0	0	0	2,983	2,907	2,466	886	792	673	452	0
1985	0	0	0	0	1,003	3,020	2,681	1,751	2,040	2,436	1,911	257
1986	0	0	0	1,837	2,995	2,206	1,875	815	1,171	1,442	71	0
1987	0	0	0	1,071	3,144	2,304	1,003	440	834	2,433	2,082	2,061
1988	896	0	24	255	3,081	2,958	2,708	1,339	1,876	2,902	1,803	676
1989	0	0	0	212	3,102	1,607	1,639	2,966	2,817	2,632	2,143	1,199
1990	201	0	0	53	2,652	3,042	2,801	1,862	1,718	1,123	1,928	2,081
1991	975	116	0	0	2,446	3,042	2,948	1,869	1,802	2,786	1,937	1,120
1992	192	0	0	73	2,702	2,698	2,133	2,171	1,739	2,390	1,365	169
1993	0	0	0	0	2,109	2,621	2,972	1,884	1,787	2,453	1,207	245
1994	0	0	0	0	2,136	2,881	2,444	2,168	2,112	2,326	2,699	1,059
1995	0	0	0	0	2,355	2,871	2,699	1,383	1,808	1,781	2,541	1,289
1996	1,052	168	497	1,468	3,144	2,765	3,009	1,554	648	2,012	2,300	298
1997	0	0	0	23	2,605	3,038	3,117	2,244	1,722	2,386	2,290	1,608
1998	388	0	1,225	1,669	3,083	2,566	1,938	1,672	2,725	2,908	2,271	1,005
1999	142	306	93	901	2,995	2,269	1,831	2,245	1,443	2,283	2,032	1,445
2000	95	0	285	524	2,779	3,042	2,951	487	197	1,275	2,268	1,014
2001	120	0	187	500	2,809	2,689	2,530	837	1,690	2,013	2,670	1,755
2002	1,208	0	0	358	2,195	2,664	2,115	2,357	2,231	1,883	1,598	663
2003	0	0	0	622	3,144	2,739	2,587	2,281	1,120	1,391	2,055	1,096
2004	141	0	0	761	3,135	2,988	895	1,238	243	1,415	246	127
2005	0	0	93	1,302	3,134	1,345	1,772	2,361	1,434	2,089	2,057	1,438
2006	0	0	154	1,780	3,144	2,032	451	221	435	1,573	2,444	1,239
2007	197	0	0	226	2,820	2,621	2,476	2,869	2,627	2,142	2,504	1,310
2008	697	0	0	1,317	3,144	2,852	1,291	1,117	1,900	2,173	1,763	1,156
2009	244	0	0	753	3,144	2,479	1,540	1,646	1,960	1,730	1,243	969
2010	810	1,213	633	2,563	3,144	3,037	2,643	1,887	604	3,020	2,989	2,977
Mean:	315	106	133	688	2,827	2,663	2,241	1,768	1,655	2,153	1,902	1,011
Max:	1,403	1,308	1,225	2,563	3,144	3,042	3,117	3,119	2,817	3,053	2,989	2,977
Min:	0	0	0	0	1,003	1,345	451	221	197	673	71	0

Table E-10 **Coastal Labrador Hydro**

Estimated Annual Energy for Final Potential Sites - With Riparian Flow **Phase 2**

Calendar Year	Year Index	Annual Energy Generated (Run-of-River) (MWh)			
		Site 11	Site MK S-2	Site 8c	Site ALX
1978	1	-	-	27,381	17,234
1979	2	12,301	4,723	34,470	21,939
1980	3	12,654	4,342	28,983	21,663
1981	4	12,619	4,419	30,182	19,651
1982	5	12,416	3,834	27,742	17,561
1983	6	12,128	4,175	30,096	20,818
1984	7	12,025	3,775	22,684	11,159
1985	8	11,634	3,246	23,182	15,100
1986	9	12,154	3,642	24,252	12,412
1987	10	11,877	4,434	25,747	15,372
1988	11	12,098	3,400	29,636	18,517
1989	12	11,253	3,963	26,739	18,318
1990	13	12,473	3,387	28,149	17,462
1991	14	11,391	3,992	30,034	19,042
1992	15	11,484	3,663	27,269	15,632
1993	16	10,178	2,979	24,763	15,278
1994	17	11,700	3,773	26,172	17,824
1995	18	12,074	2,979	26,843	16,727
1996	19	12,647	3,707	30,331	18,915
1997	20	11,646	3,872	27,290	19,033
1998	21	12,575	4,168	32,065	21,451
1999	22	12,619	4,331	30,718	17,985
2000	23	12,603	3,367	26,756	14,917
2001	24	11,631	4,560	28,606	17,799
2002	25	12,619	3,921	29,177	17,273
2003	26	12,617	3,497	27,612	17,035
2004	27	12,654	4,159	23,653	11,190
2005	28	12,619	4,249	28,100	17,024
2006	29	12,619	4,305	24,515	13,473
2007	30	12,619	3,619	28,804	19,791
2008	31	12,166	3,766	29,834	17,410
2009	32	12,500	2,573	27,952	15,709
2010	33	12,619	3,475	33,043	25,520
Mean:		12,163	3,822	27,963	17,462
Max:		12,654	4,723	34,470	25,520
Min:		10,178	2,573	22,684	11,159
Coefficent of Variation (%):		5%	13%	10%	18%

Table E-11

Site 11 monthly energy hydro site generation deficits and diesel generation

Month	Monthly Energy Demand a/ (MWh)	Hydro Site Generation b/ (MWh)	% of Demand Satisfied by Hydro Generation (%)	Energy Shortfall (MWh)	% of Demand Satisfied by Diesel Generation (%)
Jan	897	897	100%	0	0%
Feb	830	830	100%	0	0%
Mar	895	895	100%	0	0%
Apr	702	702	100%	0	0%
May	762	762	100%	0	0%
Jun	701	701	100%	0	0%
Jul	728	728	100%	0	0%
Aug	614	614	100%	0	0%
Sep	698	698	100%	0	0%
Oct	801	801	100%	0	0%
Nov	853	853	100%	0	0%
Dec	1,058	1,058	100%	0	0%
Total	9,538	9,538	100%	0	0%

a/ Peak load duration is assumed to be 24 hours.

b/ If generation is greater than demand it is made equal to demand.

Table E-12

Site MK S-2 monthly energy hydro site generation deficits and diesel generation

Month	Monthly Energy Demand a/ (MWh)	Hydro Site Generation b/ (MWh)	% of Demand Satisfied by Hydro Generation (%)	Energy Shortfall (MWh)	% of Demand Satisfied by Diesel Generation (%)
Jan	623	29	5%	594	95%
Feb	536	3	1%	533	99%
Mar	534	1	0%	533	100%
Apr	496	24	5%	472	95%
May	509	421	83%	88	17%
Jun	454	454	100%	0	0%
Jul	756	672	89%	84	11%
Aug	758	540	71%	218	29%
Sep	624	506	81%	118	19%
Oct	566	566	100%	0	0%
Nov	644	316	49%	328	51%
Dec	759	112	15%	647	85%
Total	7,259	3,644	50%	3,615	50%

a/ Peak load duration is assumed to be 24 hours.
b/ If generation is greater than demand it is made equal to demand.

Table E-13

Site 8C monthly energy hydro site generation deficits and diesel generation

Month	Monthly Energy Demand a/ (MWh)	Hydro Site Generation b/ (MWh)	% of Demand Satisfied by Hydro Generation (%)	Energy Shortfall (MWh)	% of Demand Satisfied by Diesel Generation (%)
Jan	2,494	1,638	66%	856	34%
Feb	2,082	1,108	53%	975	47%
Mar	2,205	1,161	53%	1044	47%
Apr	1,975	1,685	85%	289	15%
May	2,531	2,531	100%	0	0%
Jun	3,134	3,017	96%	118	4%
Jul	3,188	3,018	95%	169	5%
Aug	2,980	2,840	95%	140	5%
Sep	2,747	2,717	99%	30	1%
Oct	2,809	2,809	100%	0	0%
Nov	2,872	2,871	100%	1	0%
Dec	2,701	2,411	89%	290	11%
Total	31,717	27,807	88%	3,911	12%

a/ Peak load duration is assumed to be 24 hours.
b/ If generation is greater than demand it is made equal to demand.

Table E-14

Site ALX monthly energy hydro site generation deficits and diesel generation

Month	Monthly Energy Demand a/ (MWh)	Hydro Site Generation b/ (MWh)	% of Demand Satisfied by Hydro Generation (%)	Energy Shortfall (MWh)	% of Demand Satisfied by Diesel Generation (%)
Jan	2,494	357	14%	2137	86%
Feb	2,082	116	6%	1966	94%
Mar	2,205	142	6%	2063	94%
Apr	1,975	705	36%	1270	64%
May	2,531	2,531	100%	0	0%
Jun	3,134	2,725	87%	409	13%
Jul	3,188	2,308	72%	879	28%
Aug	2,980	1,834	62%	1146	38%
Sep	2,747	1,715	62%	1032	38%
Oct	2,809	2,222	79%	586	21%
Nov	2,872	1,955	68%	918	32%
Dec	2,701	1,067	39%	1634	61%
Total	31,717	17,676	56%	14,042	44%

a/ Peak load duration is assumed to be 24 hours.
b/ If generation is greater than demand it is made equal to demand.

Appendix F

Detailed Cost Estimates and Cash Flows

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Figure 8-1: Site 11 - 2 x 750 kW
Cost Estimate

October, 2012

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
A - Civil Works					
1	**Access Road**				**$490,000**
1.1	Access	km	2.8	$175,000	$490,000
2	**Cofferdams & Dewatering**				**$657,000**
2.1	Stage 1 Cofferdams	m3	400	$30	$12,000
2.2	Stage 2 Cofferdams	m3	9,000	$30	$270,000
2.3	Stage 3 Cofferdams	m3	6,500	$30	$195,000
2.4	Dewatering	LS	1	$180,000	$180,000
3	**Non Overflow Concrete Dam**				**$96,000**
3.1	Rock Excavation	m3	50	$40	$2,000
3.2	Surface Preparation	m2	50	$80	$4,000
3.3	Concrete Dam	m3	100	$900	$90,000
4	**Spillways**				**$4,444,000**
4.1	***Left Overflow Spillway (Stage 3)***				***$2,764,000***
4.1.1	Rock Excavation	m3	700	$40	$28,000
4.1.2	Surface Preparation	m2	450	$80	$36,000
4.1.3	Concrete Dam	m3	2,400	$900	$2,160,000
4.1.4	Concrete Ogee Plug	m3	600	$900	$540,000
4.2	***Center Overflow Spillway***				***$908,000***
4.2.1	Rock Excavation	m3	200	$40	$8,000
4.2.2	Surface Preparation	m3	250	$80	$20,000
4.2.3	Concrete Dam	m3	1,100	$800	$880,000
4.3	***Right Overflow Spillway (Stage 2)***				***$772,000***
4.3.1	Rock Excavation	m3	200	$40	$8,000
4.3.2	Surface Preparation	m3	300	$80	$24,000
4.3.3	Concrete Dam	m3	400	$800	$320,000
4.3.4	Concrete Ogee Plug	m3	700	$600	$420,000
3	**Embankment Dam & Fish Ladder**				**$1,667,750**
3.1	***Dam Construction***				***$817,750***
3.1.1	Rock Excavation	m3	100	$40	$4,000
3.1.2	Foundation Preparation	m2	750	$60	$45,000
3.2.1	Compacted Fill (Transition)	m3	300	$35	$345,500
3.2.2	Impervious	m3	700	$30	$356,000
3.2.3	Random Compacted Material	m3	1,700	$30	$51,000
3.2.4	Riprap	m3	200	$50	$10,000
3.2.5	Roadway	m2	250	$25	$6,250
3.3	***Fish Ladder***				***$850,000***
3.3.1	Rock Excavation	m3	1,000	$40	$40,000
3.3.2	Concrete	m3	900	$900	$810,000
5	**PH Intake & Powerhouse**				**$5,411,500**
5.1	***PH Intake Structure***				***$2,702,000***
5.1.1	Rock Excavation (Approach Canal)	m3	5,000	$45	$560,000
5.1.2	Rock Excavation (Structure)	m3	500	$50	$360,000
5.1.3	Surface Preparation	m2	150	$80	$347,000
5.1.4	Concrete	m3	1,000	$1,100	$1,435,000
5.2	***Penstock***				***$207,000***
5.2.1	Rock Excavation	m3	500	$40	$20,000
5.2.2	Surface Preparation	m2	150	$80	$12,000
5.2.3	Concrete	m3	150	$800	$120,000
5.2.4	Penstock (D = 2.2m, L = 2 x 11m)	m	22	$2,500	$55,000
5.3	***Powerhouse Structure***				***$2,352,500***
5.3.1	Rock Excavation (Structure)	m3	3,000	$50	$150,000
5.3.2	Surface Preparation	m2	500	$80	$40,000
5.3.3	Concrete, including forms and reinforcing	m3	1,500	$1,200	$1,800,000
5.3.4	Powerhouse Superstructure	m3	1,200	$200	$240,000
5.3.5	Embedded Piping & Grounding	LS	1	$50,000	$50,000
5.3.6	Handrails, Covers etc.	LS	1	$50,000	$50,000
5.3.7	Rock Excavation (Outlet Canal)	m3	500	$45	$22,500
5.4	***Substation***				***$150,000***
5.4.1	Civil Works	LS	1	$150,000	$150,000
	Sub-Total - Civil Works				**$12,766,250**
B - Mechanical and Electrical Works					
1	**Gates & Hoist**				**$759,900**
1.1	**Diversion /Spillway Dam**				**$305,000**
1.1.1	Timber Stoplogs (4 Ea)	Ea	4	$20,000	$80,000
1.1.2	Diversion Guides (4 Sets)	Kg	15,000	$15	$225,000

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Figure 8-1: Site 11 - 2 x 750 kW
Cost Estimate

October, 2012

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
1.2	**Intake Gates & Hoist**				**$454,900**
1.2.1	Trashracks	Kg	6,200	$10	$62,000
1.2.2	Trashrack Guides	Kg	3,500	$15	$52,500
1.2.3	Timber Stoplogs	Ea	2	$40,000	$80,000
1.2.4	Stoplog Guides	Kg	6,200	$17	$105,400
1.2.3	Roller Gates	Kg	3,300	$20	$66,000
1.2.3	Roller Gate Guides	Kg	2,000	$17	$34,000
1.2.4	Gate Hoist & Housing	LS	1		$55,000
2	**Powerhouse (M&E)**				**$3,316,200**
2.1	***PH Water to Wire Equipment***				***$2,550,000***
2.1.1	Supply Water to Wire (W2W) Equipment	L.S.	1	$1,850,000	$1,850,000
2.1.2	Delivery W2W Equipment to Site	L.S.	1	$100,000	$100,000
2.1.3	Installation & Commission W2W Equipment	L.S.	1	$600,000	$600,000
2.2	**Auxiliary Mechanical System**				**$320,000**
2.2.1	Drainage & Dewatering Systems	LS	1	$45,000	$45,000
2.2.2	Fire Protection System	LS	1	$20,000	$20,000
2.2.3	Domestic & Service Water Systems	LS	1	$50,000	$50,000
2.2.4	HVAC Station System	LS	1	$60,000	$60,000
2.2.5	Piezometer Piping	LS	1	$10,000	$10,000
2.2.6	Compressed Air System	LS	1	$35,000	$35,000
2.2.7	P/H Crane (10 Tonne)	LS	1	$100,000	$100,000
2.3	**Auxiliary Electrical System**				**$145,000**
2.3.1	PH Cable trays & protective pipes	L.S.	1	$20,000	$20,000
2.3.2	LV Power & Control cables	L.S.	1	$35,000	$35,000
2.3.3	PH Fire Alarm System & Telephone Sys	L.S.	1	$40,000	$40,000
2.3.4	PH Grounding & Lighting	L.S.	1	$50,000	$50,000
2.4	***Draft Tube Closure Gate***				***$301,200***
2.4.1	Draft Tube Gates	Kg	12,000	$20	$240,000
2.4.2	Draft Tube Guides	Kg	3,600	$17	$61,200
3	**Substation & Transmission Lines**				**$7,485,000**
3.1	**Substation (Electrical)**				**$735,000**
3.1.1	Step-Up Transformer (1MVA, 34.5/4.16kV)	Ea	2	$125,000	$250,000
3.1.2	Transformer Protection	L.S.	1	$25,000	$25,000
3.1.3	34.5kV Metal-Clad, Outdoor Switchgear, 1-Cell c/w	L.S.	1	$150,000	$150,000
3.1.4	SCADA	L.S.	1	$150,000	$150,000
3.1.5	Line Disconnect Switch	L.S.	1	$50,000	$50,000
3.1.6	Interconnection with Existing DG	L.S.	1	$50,000	$50,000
3.1.7	Revenue Metering	L.S.	1	$60,000	$60,000
3.2	**Transmission Line (34.5kV)**				**$6,750,000**
3.2.1	Supply & Install Transmission Line	km	45	$150,000	$6,750,000
3.2.2	Interconnection between Towns	L.S.	1		
	Sub-Total - Mechanical & Electrical Works				**$11,561,100**
Subtotal A - Civil Works					**$12,766,250**
Subtotal B - Mechanical & Electrical Works					**$11,561,100**
Subtotal C - Construction Facilities, Indirect Cost & Labrador Factor			30%	(of A+B)	**$7,298,200**
Subtotal Without Contingencies					**$31,625,550**
Contingencies					**$3,709,410**
Civil Works			20%		**$2,553,300**
Mechanical & Electrical Works			10%		**$1,156,110**
Total Estimated Construction Cost					**$35,334,960**
Environmental, Eng, Administration and Site Inspection			7.5%		**$2,650,100**
Total Estimated Project Cost					**$37,985,060**
	Total Cost $/kW				***$25,300***

Exclusions:

-escalation beyond October, 2012
- taxes
- land
- financing
- Owner's costs

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Figure 8-2: MK S-2 - 2 x 500 kW
Cost Estimate

October, 2012

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
A - Civil Works					
1	**Access Road**				**$1,225,000**
1.1	Access Road	km	7	$175,000	$1,225,000
2	**Cofferdam & Dewatering**				**$171,000**
2.1.1	Stage 1 & 2 Cofferdams	m3	1,200	$30	$36,000
2.1.2	Dewatering	LS	1	$135,000	$135,000
3	**Dam & Diversion**				**$1,852,800**
3.1	***Gravity Dam***				***$1,558,000***
3.1.1	Rock Excavation	m3	500	$40	$20,000
3.1.2	Foundation Preparation	m2	350	$80	$28,000
3.1.3	Gravity Dam	m3	1,700	$900	$1,530,000
3.2	***Diversion & Fish Passage***				***$294,800***
3.2.1	Rock Excavation	m3	60	$40	$2,400
3.2.2	Surface Preparation	m2	60	$80	$4,800
3.2.3	Diversion & Fishway Structure	m3	300	$900	$270,000
3.2.4	Concrete Plug	m3	40	$500	$20,000
4	**Overflow Spillway**				**$983,000**
4.1.1	Rock Excavation	m3	350	$40	$14,000
4.1.2	Surface Preparation	m2	50	$80	$4,000
4.1.3	Overflow Spillway	m3	850	$900	$765,000
4.1.4	Bailey Bridge (7.5m long)	LS	2	$100,000	$200,000
5	**Power Conveyance Pipe (D = 0.9m)**				**$2,850,000**
5.1	Rock Excavation	m3	12,000	$40	$480,000
5.2	Granular Bedding	m3	2,000	$40	$80,000
5.3	Granular Fill	m3	5,000	$30	$150,000
5.4	Anchor Block	m3	200	$800	$160,000
5.5	Penstock-Fiberglass or High Density Polyethylene (HDP) (Ø = .9m, L = 1,650m)	m	1,650	$1,200	$1,980,000
6	**Intake & Powerhouse**				**$954,750**
6.1	***Intake Structure***				***$173,750***
6.1.2	Rock Excavation	m3	50	$50	$2,500
6.1.3	Surface Preparation	m2	50	$80	$4,000
6.1.4	Concrete	m3	150	$1,100	$165,000
6.1.2	Backfill	m3	50	$45	$2,250
6.1	***Powerhouse Structure***				***$681,000***
6.1.2	Rock Excavation	m3	1,100	$50	$55,000
6.1.3	Surface Preparation	m2	200	$80	$16,000
6.1.3	Concrete, including forms and reinforcing	m3	300	$1,200	$360,000
6.1.4	Powerhouse Superstructure	LS	1	$150,000	$150,000
6.1.6	Embedded Piping & Grounding	LS	1	$50,000	$50,000
6.1.7	Handrails, Covers etc.	LS	1	$50,000	$50,000
6.1	***Substation***				***$100,000***
6.1.2	Civil Works	LS	1	$100,000	$100,000
	Sub-Total - Civil Works				**$8,036,550**
B - Mechanical and Electrical Works					
1	**Intake Gates & Hoist**				**$163,000**
1.1	**Diversion /Spillway Dam**				**$58,000**
1.1.1	Timber Stoplog (1 Ea)	Ea	1	$10,000	$10,000
1.1.2	Diversion Guides (1 Sets)	Kg	3,200	$15	$48,000
1.2	**Intake Gates & Hoist**				**$105,000**
1.2.1	Trashrack	Kg	500	$10	$5,000
1.2.2	Trashrack Guides	Kg	650	$15	$9,750
1.2	Ø = 0.9 m, Maintenance Valve	Ea	2	$45,000	$90,000

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Figure 8-2: MK S-2 - 2 x 500 kW
Cost Estimate

October, 2012

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
2	**Powerhouse (M&E)**				**$2,566,400**
2.1	***PH Water to Wire Equipment***				***$1,990,000***
2.1.1	Supply Water to Wire (W2W) Equipment	LS	1	$1,400,000	$1,400,000
2.1.2	Delivery W2W Equipment to Site	LS	1	$90,000	$90,000
2.1.3	Installation W2W Equipment	LS	1	$500,000	$500,000
2.2	**Auxiliary Mechanical System**				**$185,000**
2.2.1	Drainage & Dewatering Systems	LS	1	$40,000	$40,000
2.2.2	Fire Protection System	LS	1	$15,000	$15,000
2.2.3	Domestic & Service Water Systems	LS	1	$40,000	$40,000
2.2.4	HVAC Station System	LS	1	$50,000	$50,000
2.2.5	Piezometer Piping	LS	1	$10,000	$10,000
2.2.6	Compressed Air System	LS	1	$30,000	$30,000
2.3	**Auxiliary Electrical System**				**$100,000**
2.3.1	PH Cable trays & protective pipes	LS	1	$10,000	$10,000
2.3.2	LV Power & Control cables	LS	1	$30,000	$30,000
2.3.3	PH Fire Alarm System & Telephone System	LS	1	$30,000	$30,000
2.3.4	PH Grounding & Lighting	LS	1	$30,000	$30,000
2.4	***Draft Tube Closure Gate***				***$211,400***
2.4.1	Draft Tube Gates	Kg	7,000	$20	$140,000
2.4.2	Draft Tube Guides	Kg	4,200	$17	$71,400
2.5	**Valves**				**$80,000**
2.5.1	Supply & Install Butterfly Valves Ø 0.5m	Ea	2	$15,000	$30,000
2.5.2	Supply & Install Compensation Flow Valve Ø 0.9m	Ea	1	$50,000	$50,000
3	**Substation & Transmission Lines**				**$1,510,000**
3.1	**Substation (Electrical)**		**1**		**$600,000**
3.1.1	Step-Up Transformer (0.75MVA, 34.5/4.16kV)	Ea	2	$100,000	$200,000
3.1.2	Transformer Protection	LS	1	$20,000	$20,000
3.1.3	34.5kV Metal-Clad, Outdoor Switchgear	LS	1	$120,000	$120,000
3.1.4	SCADA	LS	1	$120,000	$120,000
3.1.5	Line Disconnect Switch	LS	1	$50,000	$50,000
3.1.6	Revenue Metering	LS	1	$40,000	$40,000
3.1.7	Interconnection with Existing DG	LS	1	$50,000	$50,000
3.2	**Transmission Line (25 kV)**				**$910,000**
3.2.1	Supply & Install Transmission Line	km	7	$130,000	$910,000
	Sub-Total - Mechanical & Electrical Works				**$4,239,400**
Subtotal A - Civil Works					**$8,036,550**
Subtotal B - Mechanical & Electrical Works					**$4,239,400**
Subtotal C - Construction Facilities, Indirect Cost & Labrador Factor			30%	(of A+B)	**$3,682,800**
Subtotal Without Contingencies					**$15,958,750**
Contingencies					**$2,031,000**
Civil Works			20%		**$1,607,000**
Mechanical & Electrical Works			10%		**$424,000**
Total Estimated Construction Cost					**$17,989,750**
Environmental, Eng, Administration and Site Inspection			7.5%		**$1,350,000**
Total Estimated Project Cost					**$19,339,750**
	Total Cost $/kW				***$19,300***

Exclusions:

-escalation beyond October, 2012
- taxes
- land
- financing
- Owner's costs

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Figure 8-3: Site 8C - 2 x 2,200 kW
Cost Estimate

October, 2012

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
A - Civil Works					
1	**Access**				**$1,750,000**
1.1	Access Road	km	10	$175,000	$1,750,000
2	**Cofferdam & Dewatering**				**$930,000**
2.1.1	Stage 1 & 2 Cofferdams	m3	25,000	$30	$750,000
2.1.2	Dewatering	LS	1	$180,000	$180,000
3	**Embankment Dam, Diversion & Fish Ladder**				**$8,823,600**
3.1	***Dam Construction***				***$5,195,500***
3.1.1	Rock Excavation	m3	1,200	$40	$48,000
3.1.2	Foundation Preparation	m2	10,500	$60	$630,000
3.1.3	Compacted Fill (Transition)	m3	42,000	$35	$1,805,000
3.1.4	Slurry Wall (d = 0.75m)	m3	1,700	$850	$1,445,000
3.1.5	Random Completed Rockfill	m3	37,500	$30	$1,125,000
3.1.6	Riprap	m3	2,200	$50	$110,000
3.1.7	Roadway	m2	1,300	$25	$32,500
3.2	***Diversion***				***$1,358,100***
3.2.1	***Intake & Outlet Structure***				***$518,600***
3.2.1.1	Rock Excavation	m3	100	$40	$4,000
3.2.1.2	Surface Preparation	m2	60	$60	$3,600
3.2.1.3	Concrete	m3	680	$700	$476,000
3.2.1.4	Backfill	m3	1,000	$35	$35,000
3.2.2	***Supply & Install 4 x 3.0m Ø Drainage Culverts***				***$839,500***
3.2.2.1	Rock Excavation	m3	100	$40	$4,000
3.2.2.2	Bedding Materials	m3	650	$30	$19,500
3.2.2.3	Supply & Install (Ø = 3.0m) Fiber-glass or Steel Pipe	m	300	$2,400	$720,000
3.2.2.4	Concrete (at Slurry Wall)	m3	150	$500	$75,000
3.2.2.5	Fill Over Culverts	m3	600	$35	$21,000
3.3	***Fish Ladder***				***$2,270,000***
3.3.1	Rock Excavation	m3	9,500	$40	$380,000
3.3.2	Concrete	m3	2,100	$900	$1,890,000
4	**Spillway**				**$4,345,000**
4.1	***Rock Excavation***				***$1,330,000***
4.1.1	Approach Channel	m3	12,000	$40	$480,000
4.1.2	Shute and Side Walls	m3	16,000	$40	$640,000
4.1.3	Surface Preparation	m2	3,500	$60	$210,000
4.2	***Concrete Works***				***$3,015,000***
4.2.1	Overflow Weir	m3	1,200	$800	$960,000
4.2.2	Spillway Wing Walls + Right Wing Concrete Dam Wall	m3	1,200	$900	$1,080,000
4.2.3	Chute Slab	m3	1,250	$600	$750,000
4.2.4	Chute Walls	m3	250	$900	$225,000
5	**Power Conveyance Pipe**				**$1,515,000**
5.1	Rock Excavation	m3	5,000	$40	$200,000
5.2	Surface Preparation	m2	500	$60	$30,000
5.3	Penstock (Ø = 2.65m) Fiber-glass or Steel Pipe	m	130	$2,500	$325,000
5.4	Concrete Encasement	m3	1,200	$800	$960,000
6	**Intake & Powerhouse**				**$10,582,000**
6.1	***Intake Structure***				***$1,343,500***
6.1.1	Rock Excavation	m3	6,000	$45	$270,000
6.1.2	Surface Preparation	m2	200	$80	$16,000
6.1.3	Concrete	m3	900	$1,100	$990,000
6.1.4	Backfill	m3	1,500	$45	$67,500
6.2	***Powerhouse Structure***				***$8,664,500***
6.2.1	Rock Excavation	m3	10,100	$45	$454,500
6.2.2	Surface Preparation	m2	500	$80	$40,000
6.2.3	Concrete, including forms and reinforcing	m3	6,100	$1,200	$7,320,000
6.2.4	Powerhouse Superstructure	m3	2,800	$250	$700,000
6.2.5	Embedded Piping & Grounding	LS	1	$75,000	$75,000
6.2.6	Miscellanies Steel	LS	1	$75,000	$75,000
6.3	***Powerhouse Area & Approach Road***				***$324,000***
6.3.1	Rock Excavation	m3	5,600	$40	$224,000
6.3.2	Approach Road	m3	2,500	$40	$100,000
6.4	***Substation***				***$250,000***
6.4.1	Civil Works	LS	1	$250,000	$250,000
	Sub-Total - Civil Works				**$27,945,600**
B - Mechanical and Electrical Works					
1	**Intake Gates & Hoist**				**$788,500**
1.1	**Diversion /Spillway Dam**				**$245,000**
1.1.1	Timber Stoplogs (4 Ea)	Ea	4	$20,000	$80,000

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Figure 8-3: Site 8C - 2 x 2,200 kW
Cost Estimate

October, 2012

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
1.1.2	Stoplogs Guides (4 Sets)	Kg	11,000	$15	$165,000
1.2	**Intake Gates & Hoist**				**$543,500**
1.2.1	Trashracks	Kg	7,000	$10	$70,000
1.2.2	Trashrack Guides	Kg	2,300	$15	$34,500
1.2.3	Timber Stoplog	Ea	1	$30,000	$30,000
1.2.4	Stoplog Guides	Kg	7,400	$17	$125,800
1.2.3	Roller Gates	Kg	2,400	$20	$48,000
1.2.3	Roller Gate Guides	Kg	10,600	$17	$180,200
1.2.4	Gate Hoist & Housing	LS	1		$55,000
2	**Powerhouse (M&E)**				**$5,777,400**
2.1	***PH Water to Wire Equipment***				***$4,900,000***
2.1.1	Supply Water to Wire (W2W) Equipment	LS	1	$3,500,000	$3,500,000
2.1.2	Delivery W2W Equipment to Site	LS	1	$200,000	$200,000
2.1.3	Installation W2W Equipment	LS	1	$1,200,000	$1,200,000
2.2	**Auxiliary Mechanical System**				**$425,000**
2.2.1	Drainage & Dewatering Systems	LS	1	$50,000	$50,000
2.2.2	Fire Protection System	LS	1	$25,000	$25,000
2.2.3	Domestic & Service Water Systems	LS	1	$50,000	$50,000
2.2.4	HVAC Station System	LS	1	$95,000	$95,000
2.2.5	Piezometer Piping	LS	1	$15,000	$15,000
2.2.6	Compressed Air System	LS	1	$40,000	$40,000
2.2.7	P/H Crane (15 Tonne)	LS	1	$150,000	$150,000
2.3	**Auxiliary Electrical System**				**$170,000**
2.3.1	PH Cable trays & protective pipes	LS	1	$20,000	$20,000
2.3.2	LV Power & Control cables	LS	1	$50,000	$50,000
2.3.3	PH Fire Alarm System & Telephone Sys	LS	1	$40,000	$40,000
2.3.4	PH Grounding & Lighting	LS	1	$60,000	$60,000
2.4	***Draft Tube Closure Gate***				***$282,400***
2.4.1	Draft Tube Gates	Kg	11,400	$20	$228,000
2.4.2	Draft Tube Guides	Kg	3,200	$17	$54,400
3	**Substation & Transmission Lines**				**$4,600,000**
3.1	**Substation (Electrical)**				**$1,000,000**
3.1.1	Step-Up Transformer (2.5MVA, 34.5/4.16kV)	Ea	2	$200,000	$400,000
3.1.2	Transformer Protection	L.S.	1	$50,000	$50,000
3.1.3	34.5kV Metal-Clad, Outdoor Switchgear, 1-Cell c/w 1200A,	L.S.	1	$200,000	$200,000
3.1.4	SCADA	L.S.	1	$200,000	$200,000
3.1.5	Line Disconnect Switch	L.S.	1	$50,000	$50,000
3.1.6	Interconnection with Existing DG	L.S.	1	$50,000	$50,000
3.1.7	Revenue Metering	L.S.	1	$50,000	$50,000
3.2	**Transmission Line (34.5 kV)**				**$3,600,000**
3.2.1	Supply & Install Transmission Line	km	24	$150,000	$3,600,000
	Sub-Total - Mechanical & Electrical Works				**$11,165,900**
Subtotal A - Civil Works					**$27,945,600**
Subtotal B - Mechanical & Electrical Works					**$11,165,900**
Subtotal C - Construction Facilities, Indirect Cost & Labrador Factor			30%	(of A+B)	**$11,733,500**
Subtotal Without Contingencies					**$50,845,000**
Contingencies					**$6,705,690**
Civil Works			20%		**$5,589,100**
Mechanical & Electrical Works			10%		**$1,116,590**
Total Estimated Construction Cost					**$57,550,690**
Environmental, Eng, Administration and Site Inspection			7.5%		**$4,316,300**
Total Estimated Project Cost					**$61,866,990**
	Total Cost $/kW				***$14,100***

Exclusions:

-escalation beyond October, 2012
- taxes
- land
- financing
- Owner's costs
- Interconnection cost - CHT/PHS/MSH

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Figure 8-4: Site ALX - 2 x 2,200 kW
Cost Estimate

October, 2012

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
A - Civil Works					
1	**Access Road**				**$3,150,000**
1.1	Access Road	km	18	$175,000	$3,150,000
2	**Cofferdams & Dewatering**				**$630,000**
2.1	Cofferdams (Main & Side Branch)	m3	15,000	$30	$450,000
2.3	Dewatering	LS	1	$180,000	$180,000
3	**Non-Overflow Dam Construction**				**$1,292,750**
3.1	***Non-Overflow Dam #1***				***$344,000***
3.1.1	Rock Excavation	m3	200	$40	$8,000
3.1.2	Foundation Preparation	m2	200	$80	$16,000
3.1.3	Mass Concrete	m3	400	$800	$320,000
3.2	***Non-Overflow Dam #2***				***$332,000***
3.2.1	Rock Excavation	m3	100	$40	$4,000
3.2.2	Foundation Preparation	m2	100	$80	$8,000
3.2.3	Mass Concrete	m3	400	$800	$320,000
3.3	***Non-Overflow Dam #3***				***$616,750***
3.3.1	Rock Excavation	m3	800	$40	$32,000
3.3.2	Foundation Preparation	m2	200	$80	$16,000
3.3.3	Mass Concrete	m3	700	$800	$560,000
3.3.4	Backfill	m3	250	$35	$8,750
4	**Spillways**				**$2,135,000**
4.1	***Diversion (Overflow) Spillway (#1)***				***$1,537,000***
4.1.1	Rock Excavation	m3	10,000	$40	$400,000
4.1.2	Rock Plug	m3	700	$50	$35,000
4.1.3	Foundation Preparation	m2	300	$80	$24,000
4.1.4	Reinforced Concrete	m3	220	$900	$198,000
4.1.5	Overflow Weir Concrete	m3	800	$800	$640,000
4.1.6	Base Slab Concrete	m3	400	$600	$240,000
4.2	***Overflow Spillway (#2)***				***$418,000***
4.2.1	Rock Excavation	m3	350	$40	$14,000
4.2.2	Foundation Preparation	m2	300	$80	$24,000
4.2.3	Reinforced Concrete (End Piers)	m3	100	$1,000	$100,000
4.2.4	Overflow Weir Concrete	m3	200	$800	$160,000
4.2.5	Base Slab Concrete	m3	200	$600	$120,000
4.3	***Overflow Spillway (#3)***				***$702,000***
4.3.1	Rock Excavation	m3	550	$40	$22,000
4.3.2	Foundation Preparation	m2	500	$80	$40,000
4.3.3	Reinforced Concrete (End Piers)	m3	100	$1,000	$100,000
4.3.4	Overflow Weir Concrete	m3	450	$800	$360,000
4.3.5	Base Slab Concrete	m3	300	$600	$180,000
5	**Intake Structure**				**$1,366,000**
5.1	Rock Excavation	m3	3,500	$40	$140,000
5.2	Foundation Preparation	m2	200	$80	$16,000
5.3	Concrete Structure	m3	1,100	$1,100	$1,210,000
5.4	Approach Channel (Rock Plug)	m3	1,000	$50	$50,000
6	**Penstock**				**$2,488,000**
6.1	Rock Excavation	m3	15,000	$40	$600,000
6.2	Foundation Preparation	m2	1,600	$80	$128,000
6.3	Penstock (Ø = 3.0m) Fiber-Glass or Steel	m	400	$2,800	$1,120,000
6.4	Granular Bedding	m3	2,500	$40	$100,000
6.5	Granular Fill	m3	3,500	$30	$105,000
6.6	Rip-Rap Layer	m3	1,000	$35	$35,000
6.7	Anchor Blocks (Encasement & Bifurcation)	m3	500	$800	$400,000
7	**Powerhouse & Substation**				**$5,831,000**
7.1	***Structure***				***$5,581,000***
7.1.1	Rock Excavation	m3	9,500	$50	$475,000
7.1.2	Foundation Preparation	m2	1,200	$80	$96,000
7.1.3	Concrete, including forms and reinforcing	m3	3,300	$1,200	$3,960,000
7.1.4	Powerhouse Superstructure	m3	3,400	$250	$850,000
7.1.5	Embedded Piping & Grounding	LS	1	$75,000	$75,000
7.1.6	Handrails, Covers etc.	LS	1	$75,000	$50,000
7.1.7	Tailrace Channel	m3	700	$40	$50,000
7.1.8	Rock Plug	m3	500	$50	$25,000
7.2	***Substation***				***$250,000***
7.2.1	Civil Works	LS	1	$250,000	$250,000
	Sub-Total - Civil Works				**$16,892,750**

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Figure 8-4: Site ALX - 2 x 2,200 kW
Cost Estimate

October, 2012

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
B - Mechanical and Electrical Works					
1	**Gates & Hoist**				**$1,246,500**
1.1	**Diversion /Canal Spillway**				**$360,000**
1.1.1	Diversion Stoplogs (6 Ea)	Ea	6	$20,000	$120,000
1.1.2	Diversion Guides (6 Sets)	Kg	16,000	$15	$240,000
1.2	**Intake Gates & Hoist**				**$886,500**
1.2.1	Trashracks	Kg	12,600	$10	$126,000
1.2.2	Trashrack Guides	Kg	4,800	$15	$72,000
1.2.3	Timber Stoplogs	Ea	2	$30,000	$60,000
1.2.4	Stoplog Guides	Kg	7,300	$17	$124,100
1.2.3	Roller Gates	Kg	5,300	$20	$106,000
1.2.3	Roller Gate Guides	Kg	18,200	$17	$309,400
1.2.4	Gate Hoist & Housing	LS	1		$89,000
2	**Powerhouse (M&E)**				**$5,911,000**
2.1	***PH Water to Wire Equipment***				***$5,000,000***
2.1.1	Supply Water to Wire (W2W) Equipment	LS	1	$3,600,000	$3,600,000
2.1.2	Delivery W2W Equipment to Site	LS	1	$200,000	$200,000
2.1.3	Installation W2W Equipment	LS	1	$1,200,000	$1,200,000
2.2	**Auxiliary Mechanical System**				**$425,000**
2.2.1	Drainage & Dewatering Systems	LS	1	$50,000	$50,000
2.2.2	Fire Protection System	LS	1	$25,000	$25,000
2.2.3	Domestic & Service Water Systems	LS	1	$50,000	$50,000
2.2.4	HVAC Station System	LS	1	$95,000	$95,000
2.2.5	Piezometer Piping	LS	1	$15,000	$15,000
2.2.6	Compressed Air System	LS	1	$40,000	$40,000
2.2.7	P/H Crane (15 Tonne)	LS	1	$150,000	$150,000
2.3	**Auxiliary Electrical System**				**$170,000**
2.3.1	PH Cable Trays & Embedded Piping	LS	1	$20,000	$20,000
2.3.2	LV Power & Control cables	LS	1	$50,000	$50,000
2.3.3	PH Fire Alarm System & Telephone Sys	LS	1	$40,000	$40,000
2.3.4	PH Grounding & Lighting	LS	1	$60,000	$60,000
2.4	**Draft Tube Closure Gate**		1		**$316,000**
2.4.1	Draft Tube Gates	Kg	12,400	$20	$248,000
2.4.2	Draft Tube Guides	Kg	4,000	$17	$68,000
3	**Substation & Transmission Lines**				**$8,840,000**
3.1	**Substation (Electrical)**				**$1,000,000**
3.1.1	Step-Up Transformer (2.5MVA, 34.5/4.16kV)	Ea	2	$200,000	$400,000
3.1.2	Transformer Protection	L.S.	1	$50,000	$50,000
3.1.3	34.5kV Metal-Clad, Outdoor Switchgear, 1-Cell c/w 1200A, 31.5kA,	L.S.	1	$200,000	$200,000
3.1.4	SCADA	L.S.	1	$200,000	$200,000
3.1.5	Line Disconnect Switch	L.S.	1	$50,000	$50,000
3.1.6	Interconnection with Existing DG	L.S.	1	$50,000	$50,000
3.1.7	Revenue Metering	L.S.	1	$50,000	$50,000
3.2	**Transmission Line (34.5 kV)**				**$7,840,000**
3.2.1	Supply & Install Transmission Line	km	56	$140,000	$7,840,000
	Sub-Total - Mechanical & Electrical Works				**$15,997,500**
Subtotal A - Civil Works					**$16,892,750**
Subtotal B - Mechanical & Electrical Works					**$15,997,500**
Subtotal C - Construction Facilities, Indirect Cost & Labrador Factor			30%	(of A+B)	**$9,867,100**
Subtotal Without Contingencies					**$42,757,350**
Contingencies					**$4,978,350**
Civil Works			20%		**$3,378,600**
Mechanical & Electrical Works			10%		**$1,599,750**
Total Estimated Construction Cost					**$47,735,700**
Environmental, Eng, Administration and Site Inspection			7.5%		**$3,580,200**
Total Estimated Project Cost					**$51,315,900**
		Total Cost $/kW			***$11,700***

Exclusions:

-escalation beyond October, 2012
- taxes
- land
- financing
- Owner's costs
- Interconnection cost - CHT/PHS/MSH

	YEAR 1				YEAR 2				YEAR 3				YEAR 4				YEAR 5	
	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2
Costx1,000 / Quarter	142	172	208	208	205	205	755	916	1,907	5,507	6,197	4,645	3,352	4,519	5,680	2,381	675	311
Cum. Cost x 1,000	142	314	522	730	935	1,140	1,895	2,811	4,718	10,225	16,422	21,067	24,419	28,938	34,618	36,999	37,674	37,985

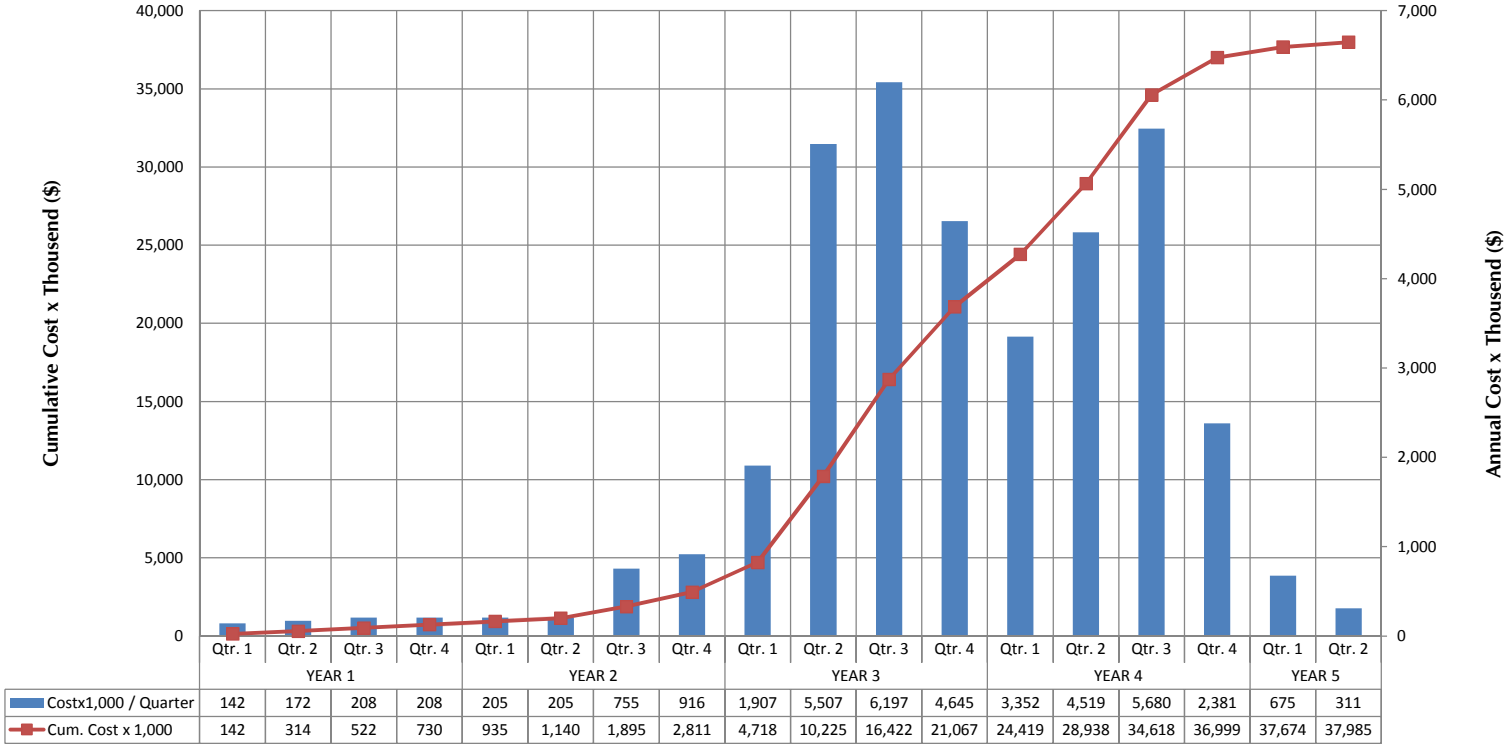


Figure 8-5: Site 11 - Annual and Cumulative Cash Flow

	YEAR 1				YEAR 2				YEAR 3				YEAR 4
	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1
Costx1,000 / Quarter	130	172	174	174	424	2,125	2,435	2,794	1,883	4,494	3,688	588	258
Cum. Cost x 1,000	130	302	476	650	1,074	3,199	5,634	8,428	10,311	14,805	18,493	19,081	19,339

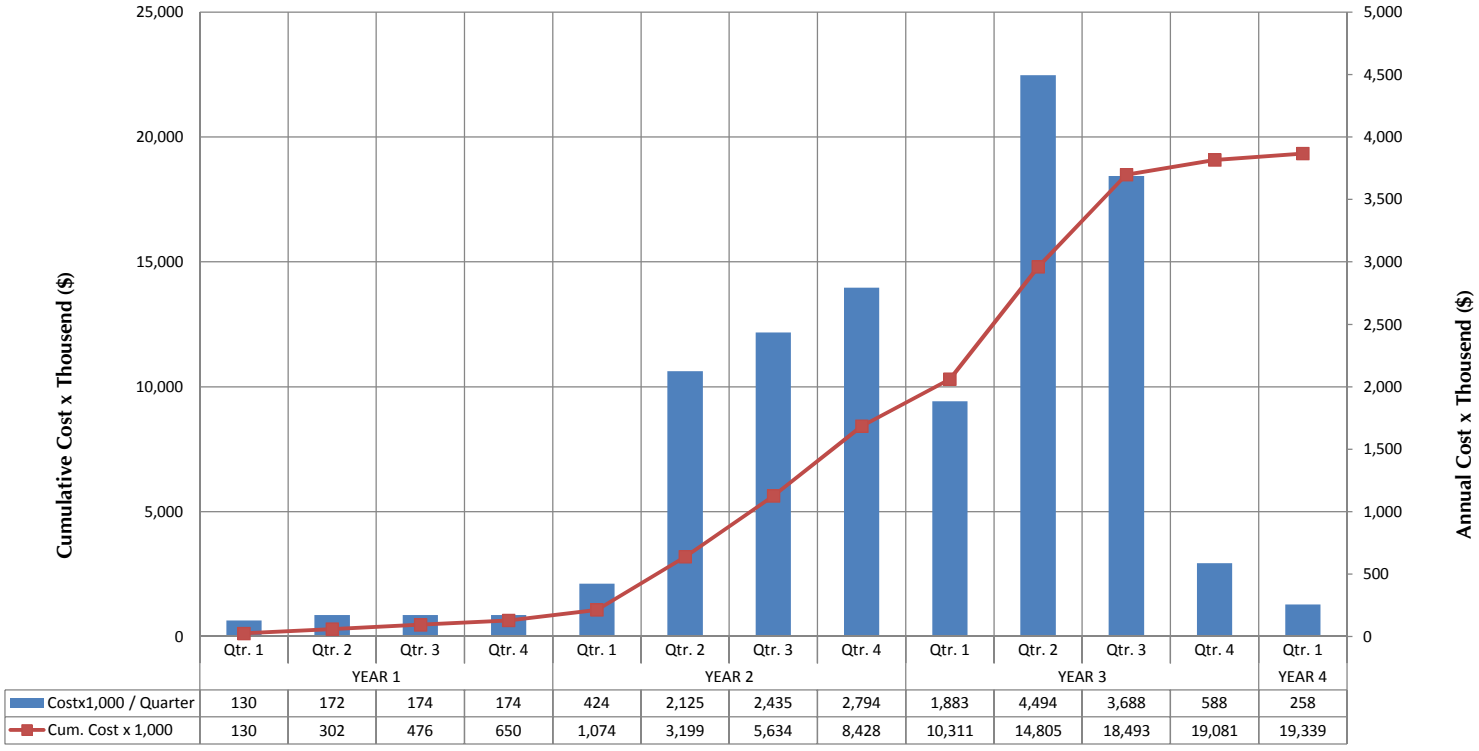


Figure 8-6: Site MK S-2 - Annual and Cumulative Cash Flow

	YEAR 1				YEAR 2				YEAR 3				YEAR 4				YEAR 5			
	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4
Costx1,000 / Quarter	289	416	439	439	433	433	1,173	1,626	1,929	5,180	6,762	6,178	4,697	9,460	7,804	6,461	5,378	1,647	610	513
Cum. Cost x 1,000	289	705	1,144	1,583	2,016	2,449	3,622	5,248	7,177	12,357	19,119	25,297	29,994	39,454	47,258	53,719	59,097	60,744	61,354	61,867

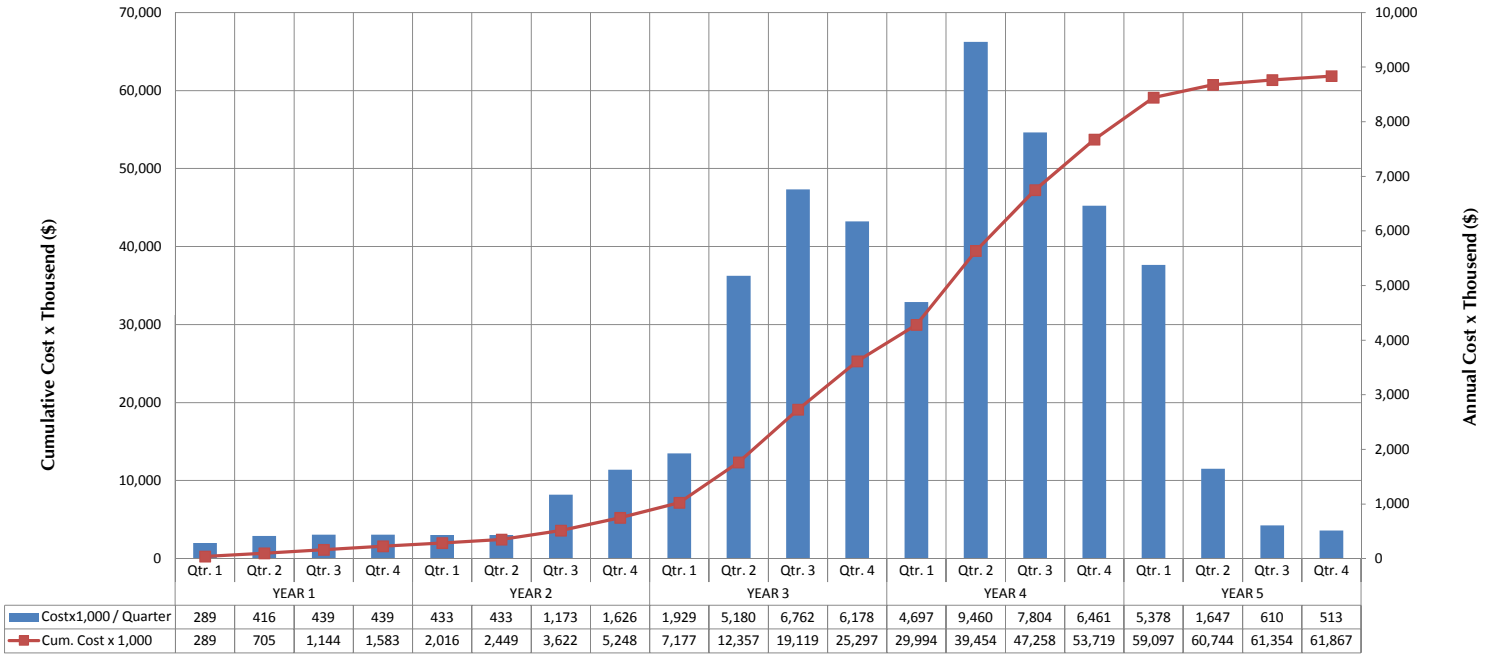


Figure 8-7: Site 8C - Annual and Cumulative Cash Flow

	YEAR 1				YEAR 2				YEAR 3				YEAR 4				YEAR 5		
	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3	Qtr. 4	Qtr. 1	Qtr. 2	Qtr. 3
Costx1,000 / Quate	249	317	352	352	347	347	1,460	1,568	2,660	6,910	8,110	8,348	7,300	5,929	3,966	2,117	598	300	85
Cum. Cost x 1,000	249	566	918	1,270	1,617	1,964	3,424	4,992	7,652	14,562	22,672	31,020	38,320	44,249	48,215	50,332	50,930	51,230	51,315

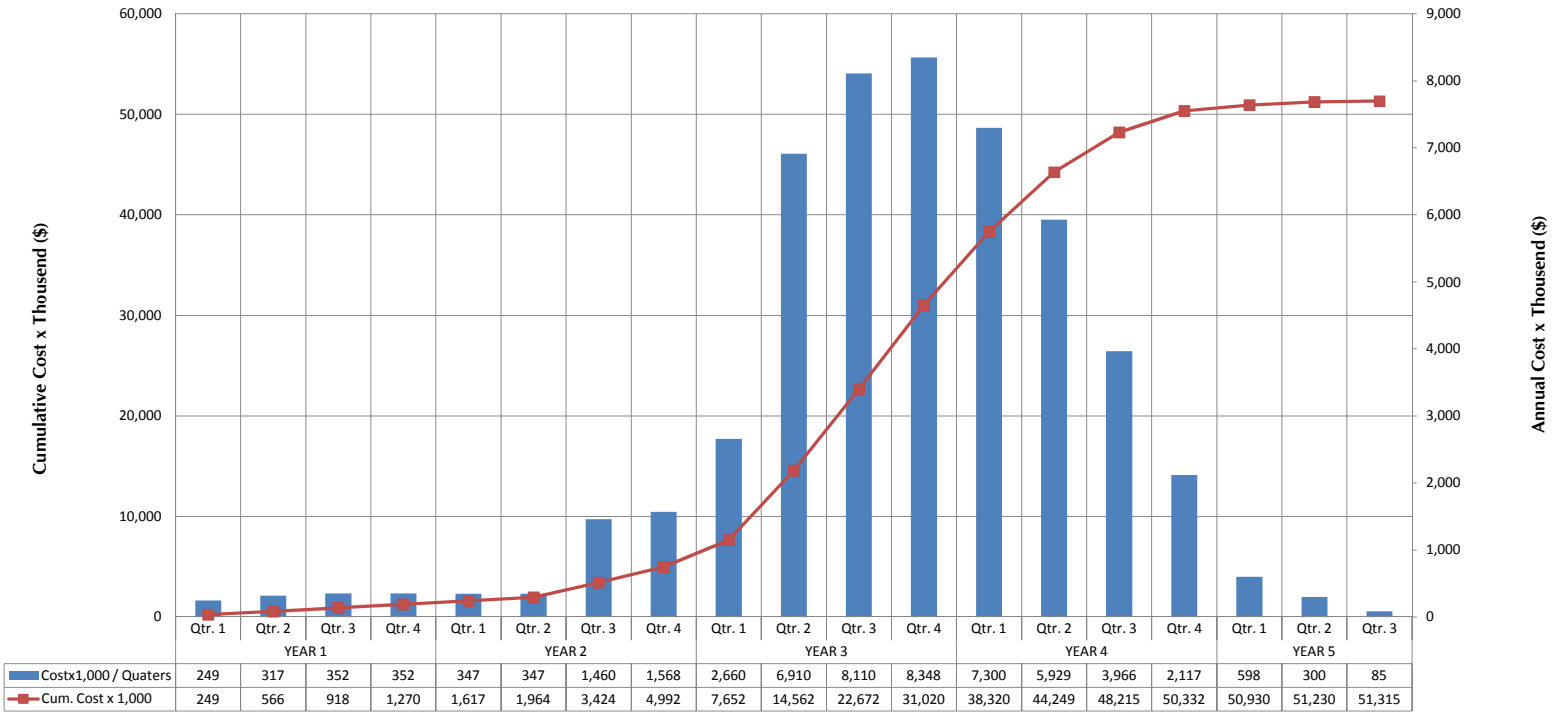


Figure 8-8: Site ALX - Annual and Cumulative Cash Flow

Appendix G

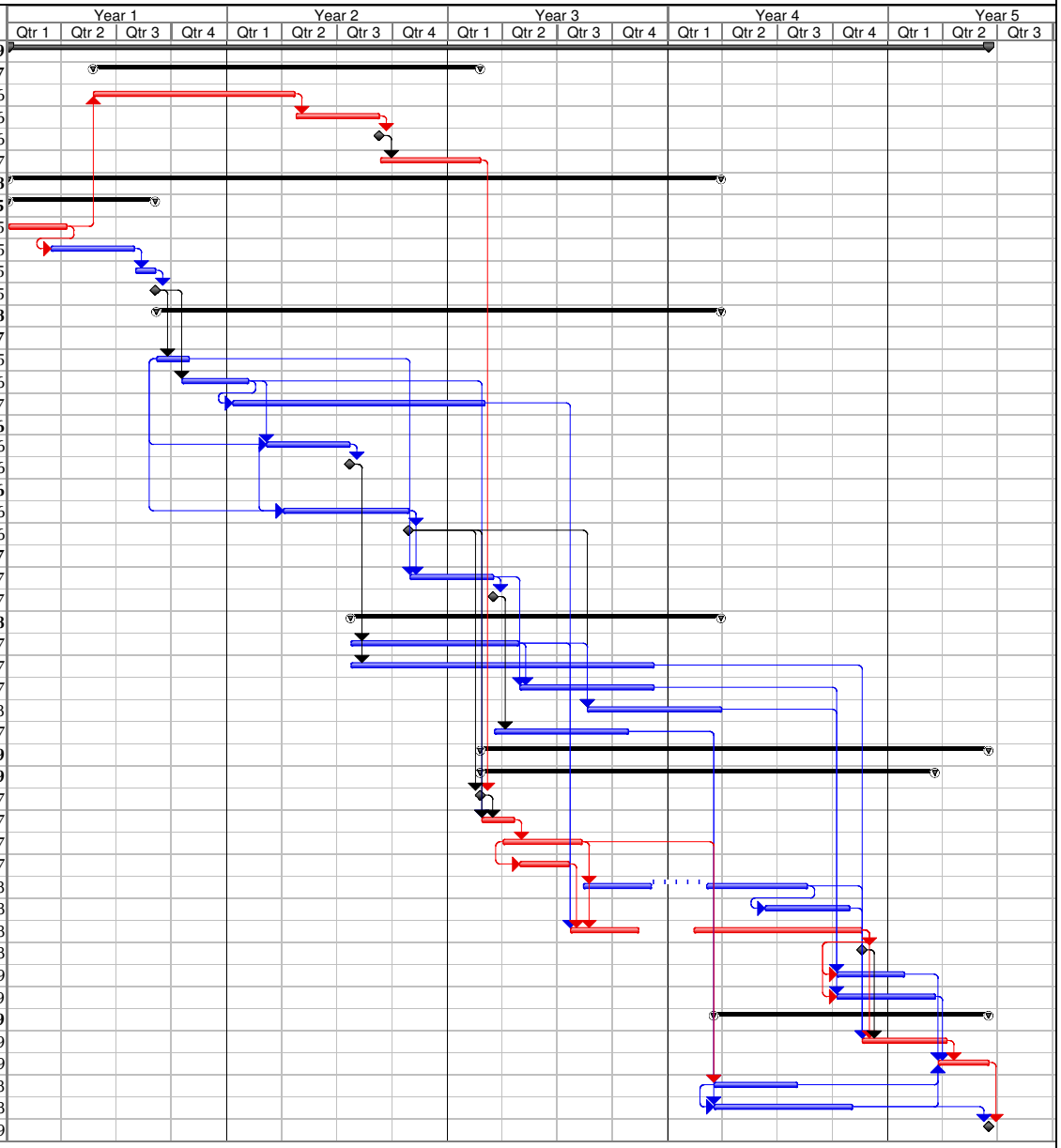
Project Schedules

Safety • Quality • Sustainability • Innovation

Figure 9-1

Coastal Labrador Hydro - Proposed Project Schedule - Site 11

ID	Task Name	Start	Finish
1	**SITE 11**	**Jan 5 '15**	**Jun 17 '19**
2	**ENVIRONMENTAL PROCESS**	**May 25 '15**	**Feb 24 '17**
3	Phase 1 - Field Studies, Consultation & Impact Assessmer	May 25 '15	Apr 22 '16
4	Phase 2 - EA Report Preparation	Apr 25 '16	Sep 9 '16
5	Notice of Completion Published	Sep 9 '16	Sep 9 '16
6	Permits & Approvals (Provincial and Federal)	Sep 12 '16	Feb 24 '17
7	**ENGINEERING, DESIGN AND PROCUREMENT**	**Jan 5 '15**	**Mar 30 '18**
8	**FEL - 3 - Project Definition Phase**	**Jan 5 '15**	**Sep 4 '15**
9	Site Investigations and Surveys	Jan 5 '15	Apr 10 '15
10	Final Engineering	Mar 16 '15	Jul 31 '15
11	Nalcor Review	Aug 3 '15	Sep 4 '15
12	Nalcor Approval to Proceed	Sep 4 '15	Sep 4 '15
13	**FEL - 4 - Implementation Phase**	**Sep 7 '15**	**Mar 30 '18**
14	**Engineering**	**Sep 7 '15**	**Mar 3 '17**
15	Tender Documents & Drawings	Sep 7 '15	Oct 30 '15
16	Final Design	Oct 19 '15	Feb 5 '16
17	Construction Drawings	Jan 11 '16	Mar 3 '17
18	**Water-to-Wire Contract (W2W)**	**Mar 7 '16**	**Jul 22 '16**
19	Bid / Evaluation Period	Mar 7 '16	Jul 22 '16
20	Contract Award	Jul 22 '16	Jul 22 '16
21	**General Contract (inc. Gates, Stoplogs)**	**Apr 4 '16**	**Oct 28 '16**
22	Bid / Evaluation Period	Apr 4 '16	Oct 28 '16
23	Contract Award	Oct 28 '16	Oct 28 '16
24	**Balance of Plant M&E**	**Oct 31 '16**	**Mar 17 '17**
25	Bid / Evaluation Period	Oct 31 '16	Mar 17 '17
26	Contract Award	Mar 17 '17	Mar 17 '17
27	**Design, Manufacture & Delivery**	**Jul 25 '16**	**Mar 30 '18**
28	Major Embedded Parts	Jul 25 '16	Apr 28 '17
29	Water-to-Wire Equipment	Jul 25 '16	Dec 8 '17
30	BOP Mechanical/Electrical Equipment	May 1 '17	Dec 8 '17
31	Gates Stoplogs, Hoisting Structures	Aug 21 '17	Mar 30 '18
32	Substation & Transmission Equipment	Mar 20 '17	Oct 27 '17
33	**CONSTRUCTION & INSTALLATION**	**Feb 24 '17**	**Jun 17 '19**
34	**Civil Works**	**Feb 24 '17**	**Mar 20 '19**
35	Commence Construction	Feb 24 '17	Feb 24 '17
36	Mobilization & Site Facilities	Feb 27 '17	Apr 21 '17
37	Access Road	Apr 3 '17	Aug 11 '17
38	Cofferdams & Diversion Facilities	May 1 '17	Jul 21 '17
39	Overflow Spillway	Aug 14 '17	Aug 20 '18
40	Non-Overflow Dam and Fishway Construction	Jun 11 '18	Oct 29 '18
41	Intake, Penstocks, Powerhouse & Substation	Jul 24 '17	Nov 19 '18
42	Powerhouse Enclosed	Nov 19 '18	Nov 19 '18
43	Install Intake & DT Gates & Stoplogs	Oct 8 '18	Jan 28 '19
44	Install E&M Equipment & Services	Oct 8 '18	Mar 20 '19
45	**W2W Equipment & Swyd & Transmission**	**Mar 19 '18**	**Jun 17 '19**
46	W2W Erection	Nov 19 '18	Apr 8 '19
47	Testing & Commissioning	Mar 25 '19	Jun 17 '19
48	Substation (Electrical)	Mar 19 '18	Aug 3 '18
49	Transmission Line (34.5 kV)	Mar 19 '18	Nov 2 '18
50	**In-Service**	Jun 17 '19	Jun 17 '19



Project: SHL-Site 11
Date: Nov 18 '12

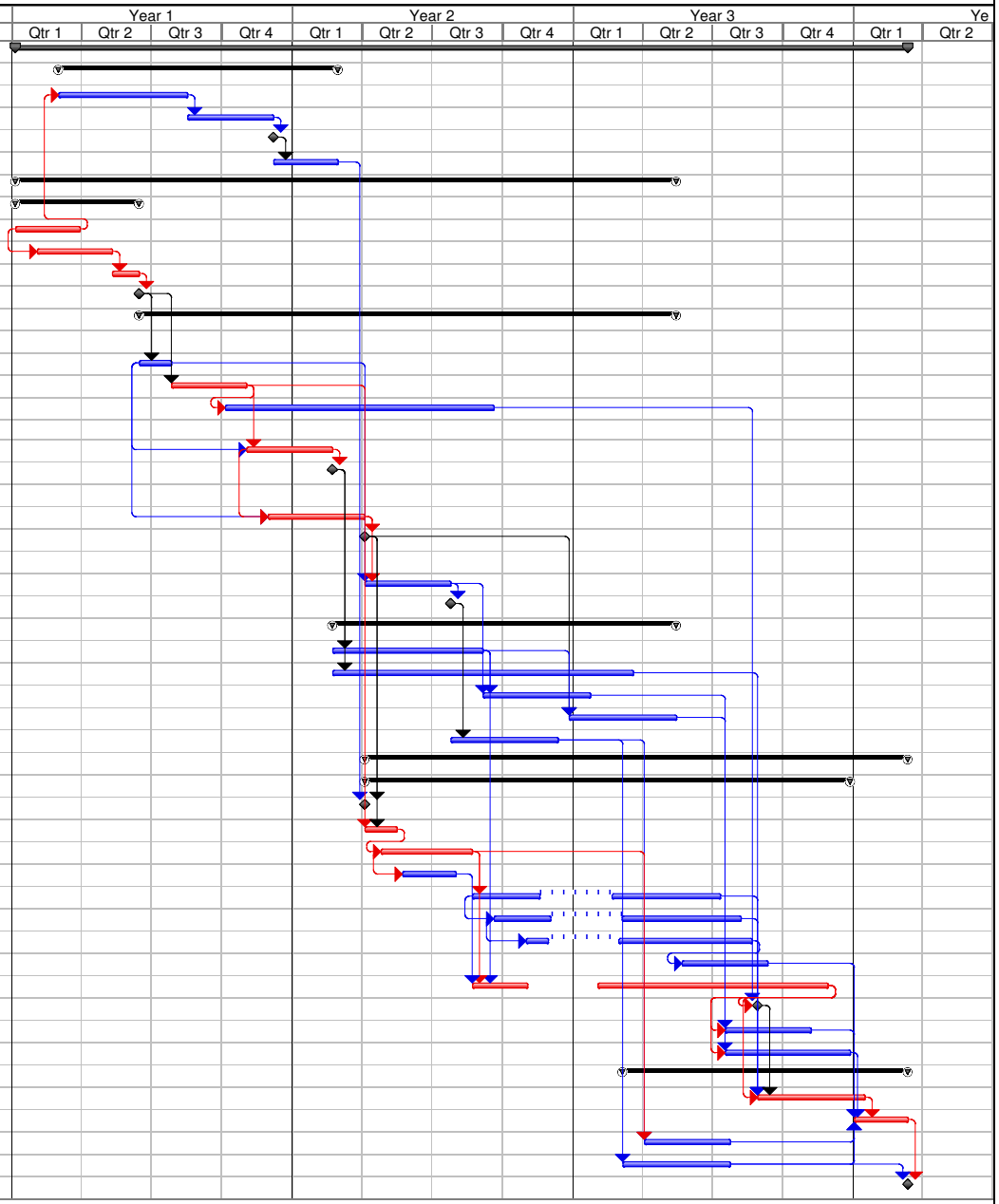
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Critical — Task — Split — Milestone ◆ — Summary

Figure 9-2

Coastal Labrador Hydro - Proposed Project Schedule - Site MK S-2

ID	Task Name	Start	Finish
1	**SITE MKS-2**	**Jan 6 '15**	**Mar 13 '18**
2	**ENVIRONMENTAL PROCESS**	**Mar 3 '15**	**Feb 29 '16**
3	Phase 1- Field Studies, Consultation & Impact Assessment	Mar 3 '15	Aug 17 '15
4	Phase 2- EA Report Preparation	Aug 18 '15	Dec 7 '15
5	Notice of Completion Published	Dec 7 '15	Dec 7 '15
6	Permits & Approvals (Provincial and Federal)	Dec 8 '15	Feb 29 '16
7	**ENGINEERING, DESIGN AND PROCUREMENT**	**Jan 6 '15**	**May 15 '17**
8	**FEL - 3 - Project Definition Phase**	**Jan 6 '15**	**Jun 15 '15**
9	Site Investigations and Surveys	Jan 6 '15	Mar 30 '15
10	Final Engineering	Feb 3 '15	May 11 '15
11	Nalcor Review	May 12 '15	Jun 15 '15
12	Nalcor Approval to Proceed	Jun 15 '15	Jun 15 '15
13	**FEL - 4 - Implementation Phase**	**Jun 16 '15**	**May 15 '17**
14	**Engineering**	**Jun 16 '15**	**Sep 19 '16**
15	Tender Documents & Drawings	Jun 16 '15	Jul 27 '15
16	Final Design	Jul 28 '15	Nov 2 '15
17	Construction Drawings	Oct 6 '15	Sep 19 '16
18	**Water-to-Wire Contract (W2W)**	**Nov 3 '15**	**Feb 22 '16**
19	Bid / Evaluation Period	Nov 3 '15	Feb 22 '16
20	Contract Award	Feb 22 '16	Feb 22 '16
21	**General Contract (inc. Gates, Stoplogs)**	**Dec 1 '15**	**Apr 4 '16**
22	Bid / Evaluation Period	Dec 1 '15	Apr 4 '16
23	Contract Award	Apr 4 '16	Apr 4 '16
24	**Balance of Plant M&E**	**Apr 5 '16**	**Jul 25 '16**
25	Bid / Evaluation Period	Apr 5 '16	Jul 25 '16
26	Contract Award	Jul 25 '16	Jul 25 '16
27	**Design, Manufacture & Delivery**	**Feb 23 '16**	**May 15 '17**
28	Major Embedded Parts	Feb 23 '16	Sep 5 '16
29	Water-to-Wire Equipment	Feb 23 '16	Mar 20 '17
30	BOP Mechanical/Electrical Equipment	Sep 6 '16	Jan 23 '17
31	Gates Stoplogs, Hoisting Structures	Dec 27 '16	May 15 '17
32	Substation & Transmission Equipment	Jul 26 '16	Dec 12 '16
33	**CONSTRUCTION & INSTALLATION**	**Apr 4 '16**	**Mar 13 '18**
34	**Civil Works**	**Apr 4 '16**	**Dec 28 '17**
35	Commence Construction	Apr 4 '16	Apr 4 '16
36	Mobilization & Site Facilities	Apr 5 '16	May 16 '16
37	Access Road	Apr 26 '16	Aug 22 '16
38	Cofferdams & Diversion Facilities	May 24 '16	Aug 1 '16
39	Overflow Spillway	Aug 23 '16	Jul 12 '17
40	Non-Overflow Concrete Dam	Sep 20 '16	Aug 7 '17
41	Power Intake	Nov 1 '16	Aug 22 '17
42	Penstock Construction	May 23 '17	Sep 11 '17
43	Powerhouse & Substation (Civil)	Aug 23 '16	Nov 29 '17
44	Powerhouse Enclosed	Aug 29 '17	Aug 29 '17
45	Install Intake & DT Gates & Stoplogs	Jul 18 '17	Nov 7 '17
46	Install E&M Equipment & Services	Jul 18 '17	Dec 28 '17
47	**W2W Equipment & Swyd & Transmission**	**Mar 7 '17**	**Mar 13 '18**
48	W2W Erection	Aug 29 '17	Jan 16 '18
49	Testing & Commissioning	Jan 2 '18	Mar 13 '18
50	Substation (Electrical)	Apr 4 '17	Jul 24 '17
51	Transmission Line (34.5 kV)	Mar 7 '17	Jul 24 '17
52	**In-Service**	Mar 13 '18	Mar 13 '18



Site MK S2
Date: Nov 18 '12

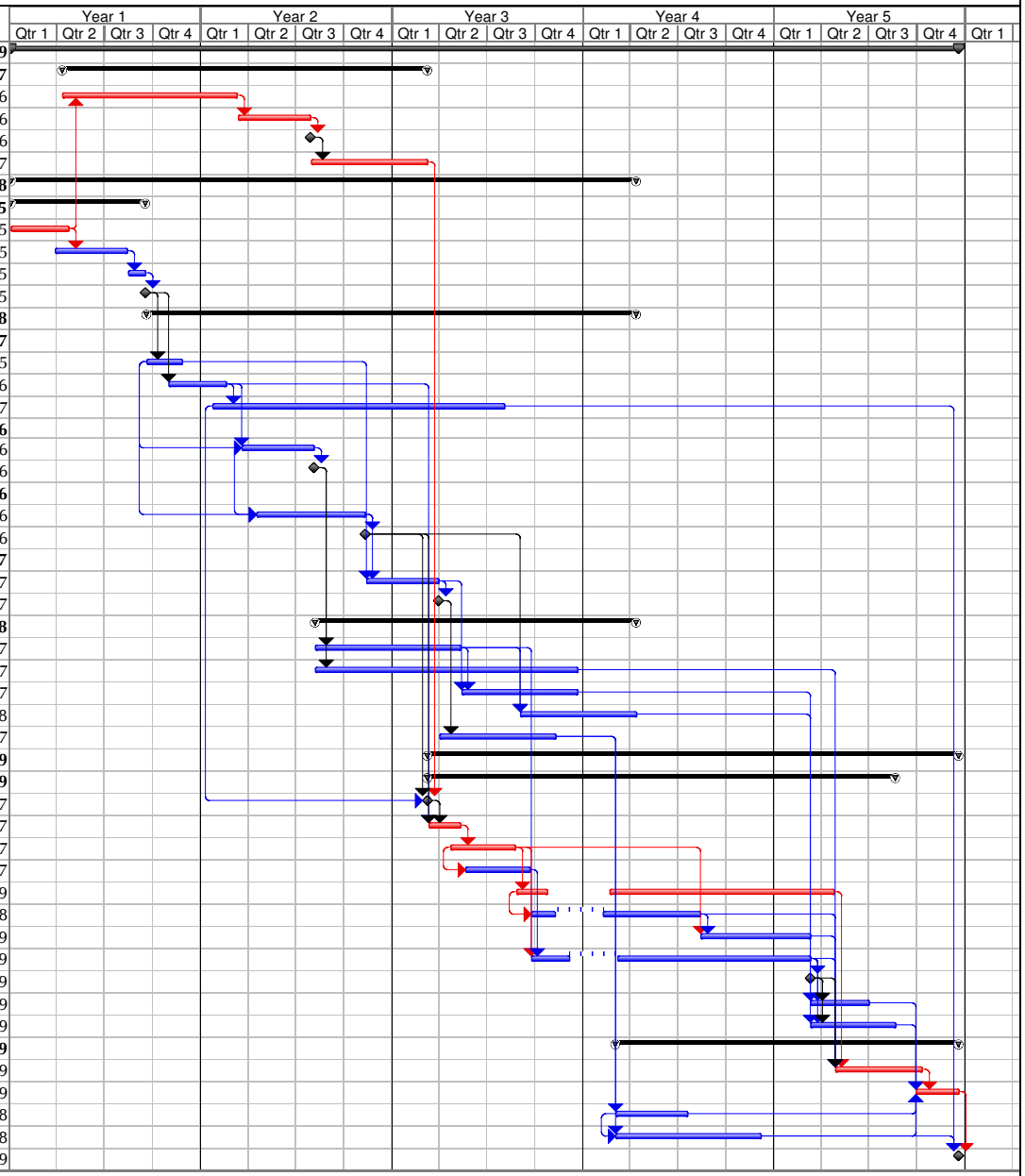
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Critical — Task — Split — Milestone ◆ — Summary

Figure 9-3

Coastal Labrador Hydro - Proposed Project Schedule - Site 8C

ID	Task Name	Start	Finish
1	**SITE 8C**	**Jan 5 '15**	**Dec 20 '19**
2	**ENVIRONMENTAL PROCESS**	**Apr 13 '15**	**Mar 10 '17**
3	Phase 1 - Field Studies, Consultation & Impact Assessment	Apr 13 '15	Mar 11 '16
4	Phase 2 - EA Report Preparation	Mar 14 '16	Jul 29 '16
5	Notice of Completion Published	Jul 29 '16	Jul 29 '16
6	Permits & Approvals (Provincial and Federal)	Aug 1 '16	Mar 10 '17
7	**ENGINEERING, DESIGN AND PROCUREMENT**	**Jan 5 '15**	**Apr 13 '18**
8	**FEL - 3 - Project Definition Phase**	**Jan 5 '15**	**Sep 18 '15**
9	Site Investigations and Surveys	Jan 5 '15	Apr 24 '15
10	Final Engineering	Mar 30 '15	Aug 14 '15
11	Nalcor Review	Aug 17 '15	Sep 18 '15
12	Nalcor Approval to Procced	Sep 18 '15	Sep 18 '15
13	**FEL - 4 - Implementation Phase**	**Sep 21 '15**	**Apr 13 '18**
14	**Engineering**	**Sep 21 '15**	**Aug 4 '17**
15	Tender Documents & Drawings	Sep 21 '15	Nov 27 '15
16	Final Design	Nov 2 '15	Feb 19 '16
17	Construction Drawings	Jan 25 '16	Aug 4 '17
18	**Water-to-Wire Contract (W2W)**	**Mar 21 '16**	**Aug 5 '16**
19	Bid / Evaluation Period	Mar 21 '16	Aug 5 '16
20	Contract Award	Aug 5 '16	Aug 5 '16
21	**General Contract (inc. Gates, Stoplogs)**	**Apr 18 '16**	**Nov 11 '16**
22	Bid / Evaluation Period	Apr 18 '16	Nov 11 '16
23	Contract Award	Nov 11 '16	Nov 11 '16
24	**Balance of Plant M&E**	**Nov 14 '16**	**Mar 31 '17**
25	Bid / Evaluation Period	Nov 14 '16	Mar 31 '17
26	Contract Award	Mar 31 '17	Mar 31 '17
27	**Design, Manufacture & Delivery**	**Aug 8 '16**	**Apr 13 '18**
28	Major Embedded Parts	Aug 8 '16	May 12 '17
29	Water-to-Wire Equipment	Aug 8 '16	Dec 22 '17
30	BOP Mechnical/Electrical Equipment	May 15 '17	Dec 22 '17
31	Gates Stoplogs, Hoisting Structures	Sep 4 '17	Apr 13 '18
32	Substation & Transmission Equipment	Apr 3 '17	Nov 10 '17
33	**CONSTRUCTION & INSTALLATION**	**Mar 10 '17**	**Dec 20 '19**
34	**Civil Works**	**Mar 10 '17**	**Aug 22 '19**
35	Commence Construction	Mar 10 '17	Mar 10 '17
36	Mobilization & Site Facilities	Mar 13 '17	May 12 '17
37	Access Road	Apr 24 '17	Aug 25 '17
38	Cofferdams & Diversion Facilities	May 22 '17	Sep 22 '17
39	Embankment Dam, Diversion & Fish Ladder	Aug 28 '17	Apr 26 '19
40	Spillway	Sep 25 '17	Aug 14 '18
41	Intake & Penstocks	Aug 14 '18	Mar 12 '19
42	Powerhouse & Substation	Sep 25 '17	Mar 12 '19
43	Powerhouse Enclosed	Mar 12 '19	Mar 12 '19
44	Install Intake & DT Gates & Stoplogs	Mar 12 '19	Jul 2 '19
45	Install E&M Equipment & Services	Mar 12 '19	Aug 22 '19
46	**W2W Equipment & Swyd & Transmission**	**Mar 5 '18**	**Dec 20 '19**
47	W2W Erection	Apr 29 '19	Oct 11 '19
48	Testing & Commissioning	Sep 30 '19	Dec 20 '19
49	Substation (Electrical)	Mar 5 '18	Jul 20 '18
50	Transmission Line (34.5 kV)	Mar 5 '18	Dec 7 '18
51	**In-Service**	Dec 20 '19	Dec 20 '19



Project: SLH-Site 8C.mpp
Date: Nov 16 ' 12

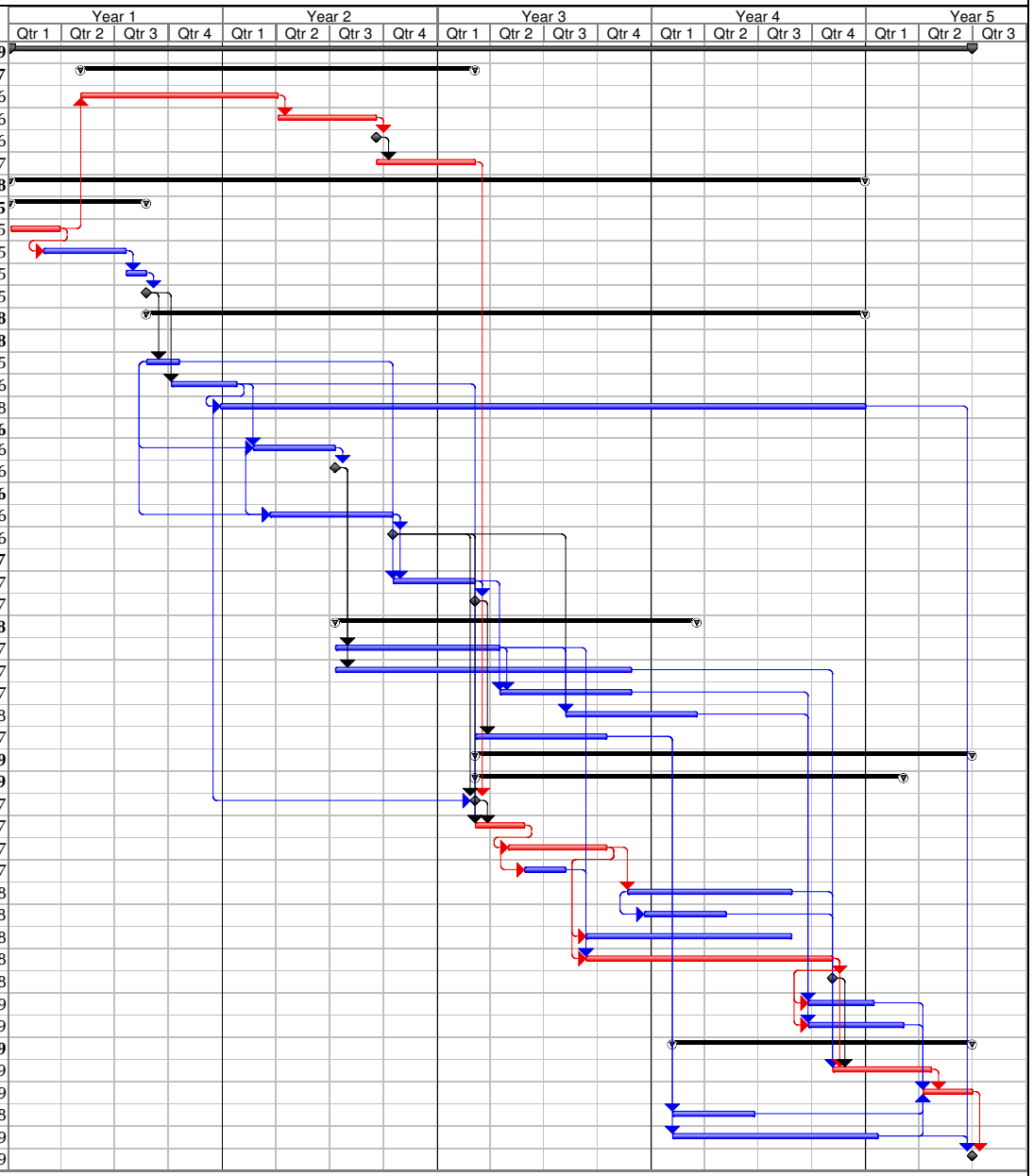
HATCH

Critical — Task — Split — Milestone ◆ — Summary

Figure 9-4

Coastal Labrador Hydro - Proposed Project Schedule - Site ALX

ID	Task Name	Start	Finish
1	**SITE ALX**	**Jan 6 '15**	**Jul 1 '19**
2	**ENVIRONMENTAL PROCESS**	**May 5 '15**	**Mar 6 '17**
3	Phase 1 - Field Studies, Consultation & Impact Assessment	May 5 '15	Apr 4 '16
4	Phase 2 - EA Report Preparation	Apr 5 '16	Sep 19 '16
5	Notice of Completion Published	Sep 19 '16	Sep 19 '16
6	Permits & Approvals (Provincial and Federal)	Sep 20 '16	Mar 6 '17
7	**ENGINEERING, DESIGN AND PROCUREMENT**	**Jan 6 '15**	**Dec 31 '18**
8	**FEL - 3 - Project Definition Phase**	**Jan 6 '15**	**Aug 24 '15**
9	Site Investigations and Surveys	Jan 6 '15	Mar 30 '15
10	Final Engineering	Mar 3 '15	Jul 20 '15
11	Nalcor Review	Jul 21 '15	Aug 24 '15
12	Nalcor Approval to Proceed	Aug 24 '15	Aug 24 '15
13	**FEL - 4 - Implementation Phase**	**Aug 25 '15**	**Dec 31 '18**
14	**Engineering**	**Aug 25 '15**	**Dec 31 '18**
15	Tender Documents & Drawings	Aug 25 '15	Oct 19 '15
16	Final Design	Oct 6 '15	Jan 25 '16
17	Construction Drawings	Dec 29 '15	Dec 31 '18
18	**Water-to-Wire Contract (W2W)**	**Feb 23 '16**	**Jul 11 '16**
19	Bid Period	Feb 23 '16	Jul 11 '16
20	Contract Award	Jul 11 '16	Jul 11 '16
21	**General Contract (inc. Gates, Stoplogs)**	**Mar 22 '16**	**Oct 17 '16**
22	Bid Period	Mar 22 '16	Oct 17 '16
23	Contract Award	Oct 17 '16	Oct 17 '16
24	**Balance of Plant M&E**	**Oct 18 '16**	**Mar 6 '17**
25	Bid Period	Oct 18 '16	Mar 6 '17
26	Contract Award	Mar 6 '17	Mar 6 '17
27	**Design, Manufacture & Delivery**	**Jul 12 '16**	**Mar 19 '18**
28	Major Embedded Parts	Jul 12 '16	Apr 17 '17
29	Water-to-Wire Equipment	Jul 12 '16	Nov 27 '17
30	BOP Mechanical/Electrical Equipment	Apr 18 '17	Nov 27 '17
31	Gates Stoplogs, Hoisting Structures	Aug 8 '17	Mar 19 '18
32	Substation & Transmission Equipment	Mar 7 '17	Oct 16 '17
33	**CONSTRUCTION & INSTALLATION**	**Mar 6 '17**	**Jul 1 '19**
34	**Civil Works**	**Mar 6 '17**	**Mar 6 '19**
35	Commence Construction	Mar 6 '17	Mar 6 '17
36	Mobilization & Site Facilities	Mar 7 '17	May 29 '17
37	Access Road	May 2 '17	Oct 16 '17
38	Cofferdams & Diversion Facilities	May 30 '17	Aug 7 '17
39	Non-Overflow Dam Construction	Nov 21 '17	Aug 28 '18
40	Overflow Spillways	Dec 19 '17	May 8 '18
41	Intake & Penstocks	Sep 12 '17	Aug 27 '18
42	Powerhouse & Substation	Sep 12 '17	Nov 5 '18
43	Powerhouse Enclosed	Nov 5 '18	Nov 5 '18
44	Install Intake & DT Gates & Stoplogs	Sep 25 '18	Jan 14 '19
45	Install E&M Equipment & Services	Sep 25 '18	Mar 6 '19
46	**W2W Equipment & Swyd & Transmission**	**Feb 6 '18**	**Jul 1 '19**
47	W2W Erection	Nov 6 '18	Apr 22 '19
48	Testing & Commissioning	Apr 9 '19	Jul 1 '19
49	Substation (Electrical)	Feb 6 '18	Jun 25 '18
50	Transmission Line (34.5 kV)	Feb 6 '18	Jan 21 '19
51	**In-Service**	Jul 1 '19	Jul 1 '19



Project: SLH-Site ALEX
Date: Nov 16' 12

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Critical — Task — Split — Milestone ◆ — Summary

Appendix H

Environmental

Safety • Quality • Sustainability • Innovation

A Consultation Plan

To Support the

Environmental Assessment

of

The Development of the

Hydraulic Potential of Coastal Labrador

Submitted to:
Hatch Ltd.
280 Torbay Road, St. John's, NL
A1A 3W8

Submitted by:
Sikumiut Environmental Management Ltd.
P.O. Box 39089
175 Hamlyn Rd.
St. John's, NL, A1E 5Y7
Phone: 709-754-0499
Fax: 709-754-1445

www.sikumiut.ca

November 15, 2012

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Appendix 2 – Information Document

Appendix 3 – List of Stakeholders

1.0 Introduction

Sikumiut Environmental Management Ltd. (Sikumiut) was engaged by Hatch Ltd. to develop a consultation program in support of the Environmental Assessment for the Development of the Hydraulic Potential of Coastal Labrador for four sites along the Labrador coast. Contacts will be made with resident stakeholders in communities on the coast of Labrador including Makkovik, Hopedale and a central community in southern Labrador.

The consultation is planned to facilitate the consideration of stakeholders regarding public issues and concerns that are relevant to the overall project and that will need to be specifically addressed in a subsequent environmental assessment report.

The consultations would be initiated with the appropriate agencies/stakeholders by a letter of introduction together with an information document outlining the project. This correspondence will invite questions and comments from stakeholders by electronic media. It can also present the opportunity for direct meetings or public sessions. The correspondence should be followed up with phone calls to confirm that the correspondence was received and to determine if any further questions or discussion is required.

2.0 The Consultation Plan

This will be a stakeholder approach to consultation:

- High level correspondence will be initiated first and foremost with the Nunatsiavut Government and NunatuKavut.
- Stakeholders in community, local government and industry sectors will then be contacted by E-mail and/or postal mail. Introductory correspondence and an information package on the project and the environmental process will be provided. Essentially, this initial contact will explain the project and invite input.
- Subsequently, discussions will be initiated with the individual stakeholders by telephone.

2.1 The Schedule

The consultation correspondence and follow-up discussions will be conducted during approximately a two week period from {date} to {date}.

- The correspondence and information package will be ready for sending to stakeholders by {date}.
- Follow-up phone contacts will be made during the following two weeks, from {date} to {date}.

2.2 Correspondence and List of Stakeholders

Correspondence will be in the form of a letter of introduction and an information package naming the companies involved, providing an overview of the study, and outlining the consultation process and schedules.

A draft letter and information package are attached in Appendices 1 and 2, respectively.

A contact list by Agency/Affiliation and Community is included as Appendix 3

2.3 Meetings

Community meetings will not be planned in the initial correspondence. However, an offer should be made to recipients to express and interest direct meetings or public sessions. In the event that such requests for group meetings or public information sessions are received, plans will be made to identify strategic locations and times for meetings and detailed plans will be executed to accommodate the majority of stakeholders.

2.4 Hatch Ltd. Coordination

Before any material is forwarded to stakeholders, it will be vetted through NL Hydro (Nalcor).

3.0 Report

A written record will be compiled of all the discussions on a community basis and highlight the issues that were raised. The main report will be provided in electronic format suitable for integration into the Project EA. Weekly reports will be submitted either verbally or as e-mail correspondence.

4.0 Protocol Considerations

First and foremost, correspondence will be sent to Nunatsiavut Government and NunatuKavut to advise of the consultations. This can be followed up with telephone contacts as required. Documents used for the meetings will be in English only.

In view of the timeline, E-mail will be used for correspondence as much as possible.

Appendix 1

Letter of Introduction

[Insert Date]

[Insert Name & Address]

Dear {Name}:

Re: Feasibility Study of Hydraulic Potential of Coastal Labrador

Hatch Ltd. is an employee-owned, multidisciplinary professional services firm that delivers a comprehensive array of technical and strategic services, including consulting, information technology, engineering, process development, and project and construction management to the Mining, Metallurgical, Energy, and Infrastructure sectors. Hatch Ltd. is in the process of an Environmental Assessment (EA) in preparation for conducting a feasibility study of selected hydro sites with hydraulic potential to generate electricity at a more competitive price than diesel fuel. As part of this EA, it has engaged Sikumiut Environmental Management Ltd. (Sikumiut) to conduct consultations as required under {name of regulations}.

[Insert brief description of project scope]

The EA is an important requirement of the planning process and necessary in acquiring government approval to carry out the project. As part of the work in preparing the EA report, consultation will be held with stakeholders in the coastal communities adjacent to the study area. The purpose of this consultation is to introduce the proposed plan and to receive local comment and concerns from the coastal areas of Labrador as it may relate to this feasibility study.

Enclosed is an information document on the project and we invite any questions or comments you may have about the project by mail, e-mail or phone. While no public sessions are currently planned we are available to discuss the project with you. Our contact information is listed below.

In addition, Sikumiut staff may contact you by phone in the near future to discuss the project and to receive your comments.

Our contacts for this consultation are:

{Name}
{E-mail}
{Telephone}
{Address}

We look forward to your participation in this consultation.

Yours truly,

_____

[Insert Proponent Information]

Appendix 2

Information Package

INTRODUCTION

Newfoundland and Labrador Hydro (NL Hydro) has carried out previous studies to evaluate the hydraulic and energy potential in coastal Labrador areas which have isolated communities. Some communities depend solely on non-renewable diesel fuel to generate their electricity and energy costs are high due to fuel purchases and transportation. There is no existing mini/small hydro or renewable energy development in coastal Labrador and power demand from existing thermal stations is expected to increase. NL Hydro commissioned a study to do a preliminary assessment of alternative energy potential of the area in 2008.

A follow-up study in 2009 by Hatch reviewed the hydraulic potential of coastal Labrador. Approximately 36 mini/small hydro sites were evaluated at a conceptual level along with their preliminary estimated costs. NL Hydro has commissioned Hatch to carry out a prefeasibility/feasibility study of selected hydro sites with hydraulic potential to generate electricity at a more competitive price than diesel fuel.

Presently, four sites have been short-listed for the next phase of the study. The communities identified for the current study are Hopedale, Makkovik, Charlottetown, Port Hope Simpson and Mary's Harbour.

THE ENVIRONMENTAL ASSESSMENT

The approach for the project has been developed to satisfy requirements of the Canada Environmental Assessment Act.

It is designed to:

- focus on issues of great concern;
- address regulatory requirements;
- considers stakeholder issues and concerns early in the planning process;
- focus project specific environmental assessments by identifying the key environmental issues associated with a particular activity and/or area.

In this particular case, Valued Environmental Components (VECs) will be included but not limited to:

- migratory birds;
- freshwater fish;
- marine anadromous fish (i.e. Atlantic Salmon);

- sensitive areas; and
- commercial fisheries.

PROJECT OVERVIEW

NL Hydro's objective is to define a cost-effective renewable power source with lower operating costs than diesel and reduced effect on the environment. An initial assessment of the site rankings and other key factors (plant capacities, proximity of communities) suggests that hydraulic energy can be provided to the five communities under consideration (Hopedale, Makkovik, Charlottetown, Port Hope Simpson and Mary's Harbour) from the development of small hydro sites.

[Insert Figure 1. Study Area]

ENVIRONMENTAL ASSESSMENT REVIEWS

The operators will periodically review the EA report, as required, to ensure that it remains applicable for the operations. It will continue stakeholders' consultation as required and will work with regulatory authorities to ensure that the EA remains fit for the purpose.

The results of environmental assessment will be used as part of the project planning and decision-making related to the issues that may be identified for consideration during the operations of this specific project.

These are:

- Fish and fish habitat (focusing on commercial species and their habitat)
- Environmental Protection;
- Migratory birds;
- Species at risk; and
- Sensitive and special areas.

Other issues may be included based on consultations with various stakeholders including the public, other resource users and regulatory authorities.

YOUR INPUT

You are invited to provide comments on these and any other factors that you feel may be impacted by these activities. You can provide your comments to Sikumiut Environmental Management Ltd. as follows:

{Name}
{E-mail}
{Telephone}
{Address}

Appendix 3

Stakeholder List

Agency	Head Office	Contact Person (s); Affiliation / Title (s)	Addresses	Tel Fax/Email
Nunatsiavut Government	Hopedale	Susan Nochasak Minister, Education & Economic Development	NG Assembly PO Box 189 Hopedale, Labrador, NL, A0P 1G0	E-mail: susan.nochasak@ nunatsiavut.com
Town Council	Hopedale	Wayne Piercy AngajukKâk	Hopedale Inuit Community Government PO Box 189 Hopedale, Labrador, NL, A0P 1G0	Tel: (709) 933-3864 Fax: (709) 933-3800 Email: wayne.piercy@nunatsiavut.com
Nunatsiavut Government	Hopedale	Ian Winters Conservation officer Dept. Lands and Natural Resources	P.O. Box 189 Hopedale, Labrador, NL, A0P 1G0	Tel: 709-933-3733 E-mail: Ian_winters@nunatsiavut.com
Nunatsiavut Government	Hopedale	Ethel Hunter Community Liaison Officer	Hopedale, Labrador, NL, A0P 1G0	Tel: 709-933-3777 ext. 231 E-mail: ethel_hunter@nunatsiavut.com
Town Council	Makkovik	Herb Jacque AngajukKâk Terry Rice, Town Manager	Makkovik Inuit Community Government P.O. Box 85 16 Andersen Street Makkovik, NL A0P 1J0	Tel: (709) 923-2221 (main) (709) 923-2299 (Town Mgr) (709) 923-2455 (H. Jacque) Fax: (709) 923-2126 Email townclerkmakkovik@nf.aibn.com townmanager@makkovik.ca herbert.jacque@nunatsiavut.com
Nunatsiavut Government	Makkovik	Carol Gear Community Liaison Officer	P.O. Box 128 Makkovik, NL A0P 1J0	Tel: 709-923-2365 ext. 201 Fax: 709-923-2186 Email: carol_gear@nunatsiavut.com
Nunatsiavut Government	Makkovik	Errol Andersen Conservation Officer Dept. Lands and Natural Resources	Makkovik Inuit Community Government P.O. Box 85 16 Andersen Street Makkovik, NL A0P 1J0	Tel: 709-923-2365 ext. 226 E-mail: errol_andersen@nunatsiavut.com

Agency	Head Office	Contact Person (s); Affiliation / Title (s)	Addresses	Tel Fax/Email
Nunatsiavut Government	Makkovik	Linda Pottle Team Leader Dept. Health and Social Development	Makkovik Inuit Community Government P.O. Box 85 16 Andersen Street Makkovik, NL A0P 1J0	E-mail; linda_pottle@ nunatsiavut.com
NunatuKavut	Happy Valley-Goose Bay	Todd Russell President	370 Hamilton River Road P.O. Box 460, Stn. C Happy Valley-Goose Bay, NL A0P 1C0	Email: trussell@nunatukavut.ca
Town Council	Charlottetown	Charmaine Powell - Mayor Stewart Macnab- Town Clerk	P.O. Box 151 Charlottetown, Labrador A0K 5Y0	Tel; (709) 949-0299 Fax: (709) 949-0377 Email: powellcp@hotmail.com E-mail: ctown@nf.aibn.com
Town of Port Hope Simpson	Port Hope Simpson	Margaret Burden, Mayor Betty Sampson, Town Clerk	Port Hope Simpson, Nl, A0k 4E0	Tel: (709)960-0236 Fax: (709)960-0387 E-mail: mburden38@yahoo.ca E-mail: porthopesimpson@nf.aibn.com
Newfoundland and Labrador	Port Hope Simpson	Nina Penney Conservation Officer Dept. Natural Resources	Port Hope Simpson, Nl, A0K 4E0	E-mail: ninapenney@gov.nl.ca
Southern Labrador Economic Development Board	Port Hope Simpson	Roxanne Notley, Economic Development Manager Margaret Rumbolt, Economic Development Officer	Port Hope Simpson, Nl, A0K 4E0	Tel: (709) 960-0470 E-mail: roxanne.notley@nf.aibn.com E-mail: margaret.rumbolt@nf.aibn.com
Town Council	St. Lewis	Annie Rumbolt - Mayor	P.O.Box 106 St Lewis, Nl, A0K 4W0	Tel: (709) 939-2282 Fax: (709) 939-2210
Town Council	St-Lewis	Lorraine Poole ,town clerk	P.O.Box 106 St Lewis, Nl, A0K 4W0	Tel: (709) 939-2282 Fax: (709) 939-2210 E-mail:stlewistownoffice@nf.sympatico.ca
Town Council	Mary's Harbour	Larry Rumbolt, Mayor Glynes Rumbolt, Town Clerk	P.O. Box 134 Mary's Harbour, Nl, A0K 3P0	Tel: (709) 921-6281 Fax: (709) 921-6255 E-mail: larry_rumbolt@yahoo.com E-mail: maryshbr@nf.aibn.com

Agency	Head Office	Contact Person (s); Affiliation / Title (s)	Addresses	Tel Fax/Email
Southern Labrador Economic Development Board	Mary's Harbour	Byron Rumbolt, Natural Resources Director	Mary's Harbour, Nl, A0K 3P0	Tel: (709)921-6875 E-mail: brumbolt@live.ca
Battle Harbour Regional Development Association	Mary's Harbour	Gina Pye, development coordinator	P.O. Box 131, Mary's Harbour, A0K 3P0	Tel: (709) 921-6957 Fax: (709) 921-6993 E-mail:bhrda@nf.aibn.com
Department of Fisheries and Oceans Canada	St. John's	Carole Grant Section Head, Habitat Evaluation Marine Environment and Habitat Management	P.O. Box 5667 St. John's NL A1C 5X1	Tel: (709) 772-2506 E-mail: carole.grant@dfo-mpo.gc.ca
NL Department of Fisheries and Aquaculture	St. John's	Tom Dooley, Director, Resource Policy	P.O. Box 8700 St. John's, NL, A1B 4J6	Tel: 709-729-0335 Fax: 709-729-6082 Email: tdooley@gov.nl.ca
NL Department of Natural Resources	St. John's		P.O. Box 8700 St. John's NL A1B 4J6	Tel: (709) 729-2778 Fax: (709) 729-2508 E-mail: fallen@gov.nl.ca
NL Department of Environment and Conservation	St. John's	Martin Goebel Assistant Deputy Minister	PO Box 8700 St. John's NL A1B 4J6	Tel: 709-**729-2559** Fax: (709) 729-7413 E-mail: mgoebel@gov.nl.ca
Environment Canada	St. John's	Glenn Worthman	6 Bruce Street Mount Pearl NL A1N 4T3	Tel: (709)772-4047 E-mail: glenn.worthman@ec.gc.ca

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Annex

Potential Storage

Newfoundland and Labrador Hydro
Feasibility Study of Hydraulic Potential of Coastal Labrador

Phase 2: Project Definition Phase - Annex – Potential Storage

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1. Introduction, Objectives and Scope of Work

1.1 Introduction

1.1.1 Background

It was concluded in the Phase 2 Coastal Labrador study that, for the southern communities, storage/reserve hydroelectric power is required to fully displace existing diesel power in certain towns, as run-of-river waterpower is non-dispatchable. The direction prescribed by Newfoundland and Labrador Hydro (NLH) prior to the Phase 1 Advanced Screening studies was to have one hydro site/plant for the combined towns of CHT, PHS and MSH.

At a meeting with NLH on December 12, 2012, Hatch noted that based on the findings of the Phase 2 Coastal Labrador study, it is unlikely that full displacement of diesel generation could be achieved with one new small-hydro plant (with a capacity of approximately 5 MW) located in the vicinity of CHT/PHS/MSH, on the St. Lewis River, or on the Alexis River. Hatch recommended looking at two (or three) small hydro plants.

One of the reasons for suggesting two plants was because a site with a large upstream pond on the Gilbert River south of the town of Charlottetown was screened and assessed in Phase 1. Although a one only plant at this site (Site 5) could not supply sufficient energy for the combined towns of CHT, PHS and MSH, it could meet the demands of CHT, and offers storage capacity. Site 5 is located approximately 12 km south of CHT. Additionally, it was suggested that it would be technically feasible to construct and operate a second hydro plant on either the St. Lewis or on the Alexis River that combined with a plant at Site 5, adequate energy could be supplied to satisfy power and energy demands for the four south coast towns, supplementing existing diesel power.

Site 8C (Phase 2 Study) on the St. Lewis River is not a natural site for storage; therefore alternative dam sites were assessed. It was decided that it may be technically feasible to have a high dam downstream of Site 8C that has potential for creation of a conservation reservoir.

Similarly, the existing surrounding terrain at Site ALX on the Alexis River does not lend itself to creation of a storage reservoir at the Phase 2 proposed dam site. Nonetheless, raising of the proposed dam would create a small conservation reservoir.

Based on Hatch's recommendations, it was agreed that further assessment of potential storage on the three rivers (Gilbert, St. Lewis and Alexis), and preparation of scheme layouts was required. Aerial photography was immediately ordered and subsequently obtained on January 21, 2013 through the Department of Environment and Conservation for preparation of additional digital mapping. The additional digital mapping for the sites was prepared and delivered by mid-February 2013. Figure 1-1 in Attachment 1 provides a project location map showing the proposed site locations and the towns.

At a meeting between NLH and Hatch on January 10, 2013, Hatch was requested to complete a rapid high level review without the availability of additional mapping followed by a detailed analysis/confirmation study after digital mapping was received. It was also agreed that the 25 year forecast energy requirement (2037) used for this study would include the small town of St. Lewis (STL).

A preliminary report summarized the findings of Hatch's rapid review and scoping study of the potential hydroelectric sites with conservation storages that may be capable of delivering the credited firm power to the communities, displacing existing diesel generation. The preliminary scoping report was completed and submitted to NLH on January 28, 2013. Work on the detailed study with the new mapping and topography commenced in February 2013 and this Annex summarizes Hatch's findings and conclusions on the feasibility of the potential hydroelectric projects with conservation storages to deliver firm power to the southern Labrador towns that would offer the displacement of diesel generation.

1.2 Objectives and Scope of Work

The primary objective of this study (Annex – Potential Storage) was to evaluate potential hydroelectric sites from those previously screened sites that may satisfy the power and energy requirements of the southern block of communities of Charlottetown (CHT), Port Hope Simpson (PHS), Mary's Harbour (MHS), and St. Lewis (STL). The study used the findings of the preliminary study as a base from which more detailed analysis was carried out to verify the conservation storage volumes available or created by dam construction and the hydroelectric potential of the sites to deliver firm power.

This study focused primarily on the technical viability of the proposed developments and the potential for storage and establishes the firm energy yield for a specific level of hydrologic reliability. Design layouts were prepared from the recently completed topographic mapping and design variables and parameters verified. Detailed cost estimates based on take-off quantities are included for the hydro developments assessed. A preliminary economic analysis to determine the levelized unit energy cost of the most economic scheme is also included in this Annex.

1.3 Approach and Methodology

The first task in the study was to examine previously studied candidate small hydro schemes and perform a rapid evaluation of generation options with storage reservoirs that may fully supplant diesel generation at the respective communities. This entailed a quick examination of dam sites and their potential for an upstream reservoir.

1.3.1 Communities and Potential Storage Sites

It was determined that the community of CHT could be served by Site 5 on the Gilbert River. PHS, MHS and STL (combined) could be served by either one small hydro plant on the St. Lewis River, or one on the Alexis River. The forecasted capacity required at CHT in 2037 is about 1850 kW and the corresponding forecasted capacity for PHS/MHS/STL is about 2800 kW. Therefore, the revised nominal installed capacities at the sites were initially chosen as follows: Site 5 – 2.0 MW, Site 8 or Site ALX - 3.0 MW. It was recognized that these would

need to be adjusted and rated slightly larger to accommodate the fluctuating head on the plants as a result of reservoir drawdown over each year.

A rapid assessment of available and potential storage reservoirs at the sites was initially based on 1:50,000 topographical mapping in addition to existing survey data used in our previous evaluations and feasibility studies of the sites. Reservoir storage volume curves were prepared based on the layers of submerged areas demarcated at each site from the 1:50,000 contour maps. Reservoir storage would be seasonal therefore a minimum base period of a year was adopted. All information on site potential storage volumes was subsequently updated, revised and verified with the new topographic mapping. Revised elevation/capacity reservoir curves were derived. Map datums and river levels taken from the 1:50,000 mapping were revised to the new information accordingly.

Approximate reservoir operation levels were selected and the required live volumes for the storage sites to deliver the design reservoir drafts were first derived from the site flow duration curves. These were subsequently verified by a volumetric water balance using inflows, outflows (including spills) and power flows over a critical year. Once reservoir yield was verified the next steps were to undertake layouts of the schemes, refine the power flows and sizes of water conductors, and, estimate generation at the respective sites.

Reservoir storage volume curves were prepared and are included in Section 4 of this Annex. Reservoir inundation maps were also produced, and are provided in Attachment 1, Figures 1-2, 1-3, 1-4 and 1-5.

1.3.2 Generation Options for Displacing Diesel Power

Combinations of hydro sites which may entirely displace diesel generation were investigated. Several candidate hydro schemes or combination of generation options were examined prior to arriving at two preferred generation options that may totally supplant diesel generation at the communities.

Initial potential schemes identified and considered which may satisfy energy requirements included:

- One ~5 MW plant downstream of the falls on the St. Lewis River with storage (disregards the existing tourist lodge).
- One ~5 MW plant on the St. Lewis River located at the tourist lodge falls with storage (also disregards the existing tourist lodge).
- Two small hydro plants: One ~2 MW plant at Site 5 on the Gilbert River (now called Site 5B to distinguish it from Site 5 in Phase 1) with storage plus one ~3 MW plant on the St. Lewis River with storage.
- Two small hydro plants: One ~2 MW plant at Site 5B with storage in addition to one ~3 MW plant on the Alexis River with storage.
- One ~5 MW plant on the Alexis River with drainage area diversion and storage.

- Three small hydro plants: Charlottetown served by Site 5, Port Hope Simpson and St. Lewis served by Site 8 or Site ALX, and, Mary's Harbour served by Site 4.

Based on the initial analyses the potentially feasible generation options were segregated into the following two scenarios for detailed study and analysis.

Generation Option #1

Consisting of storage Site 5B to serve CHT on an isolated basis with a firm capacity of 1,850 kW and an installed capacity of 2,100 kW; plus a potential storage site, called Site 8D, (5 km downstream of Phase 2 Site 8C) with a high dam to create a conservation reservoir and a firm capacity of 2,800 kW and installed capacity of 3,500 kW to serve PHS/MSH/STL; or Site 5B; plus an alternate storage Site ALX-B approximately 900 m upstream of Phase 2 Site ALX with a high dam to create a conservation reservoir and a firm capacity of 2,800 kW and installed capacity of 3,500 kW, to serve PHS/MSH/STL.

Generation Option #2

Consisting of storage Site 5B with a firm capacity of 2300 kW plus the run-of-river Site 8C (from Phase 2) but with a reduced installed capacity of 3,000 kW (now called 8C-2), and a local isolated grid between CHT, PHS, MSH and STL. The shortfall in run-of-river generation at Site 8C-2 would be supplied from the firm power generated at storage Site 5B.

1.3.3 Reservoir Capacity and Storage Required

The reservoir capacities required to ensure a firm yield to completely displace diesel generation were first estimated by using the existing flow duration curves (FDCs) developed for Phase 1 - Advanced Screening, of eleven hydro sites. The synthesized flow series in these curves covered the years 1979-2010 (33 years). For this evaluation, constant reservoir draft rates are assumed for the preliminary sizing of reservoirs which corresponds to a uniform demand schedule of power. These were subsequently adjusted to include variable reservoir draft rates that are required to accommodate falling reservoir pool levels over a year.

The estimated draft rates were superimposed on the tail-end of the FDCs and the areas between the variable draft line and the FDC line were calculated in volume units to give the approximate storage requirements to achieve the required dependable flows at the respective sites. Initial draft rates were calculated by approximately estimating the net hydraulic heads of the respective plants as reservoir volumes are depleted.

Water supply yield for the conservation reservoirs was calculated on the basis of the driest year in the 33-year flow record (i.e. a 1 in 33 or 3% chance of occurrence). The calculation of reservoir yield is based on a volumetric water balance with monthly time steps that takes into account inflows, rainfall and evaporation falling on the reservoirs. Reservoir inflows aggregated to mean monthly flows were obtained from the synthesized streamflow records for the respective sites (site flows are in mean daily flows).

Rainfall and evaporation were based on historic values for Labrador sites as real-time data was not available. Rainfall was included as a component of evaporation (net evaporation) and converted to flow units over the monthly time step. At this stage of study no other non-power development flows or withdrawals such as ecological flows or reservoir leakage amounts were taken into account in the water balance calculations. The water balance is achieved by solving the continuity equation for change in storage in each month during the critical year. The continuity equation expressed in flow units is as follows:

$\Delta S = I - O - L$

Where: ΔS = change in reservoir storage

I = reservoir inflow

O = reservoir outflow

L = losses (evaporation, any diversions, etc)

Reservoir outflow included hydroplant discharge plus outflow not available for generation (e.g. spill, leakage, fish ladder operation, ecological flow, etc). Expanding the above equation to include all categories of losses and outflow components, the continuity equation becomes

$\Delta S = I - (Q_p + Q_l + Q_s) - (E + W)$

Where: ΔS = change in storage during routing interval (one month)

Q_p = power discharge

Q_l = leakage and non-consumptive water requirements

Q_s = spill

I = inflow

E = net evaporation losses (evaporation – rainfall)

W = withdrawals for other uses (set to zero for this stage of study)

Leakage and non-consumptive water requirements were set to zero for this study.

For a monthly time step, ΔS can be defined as:

$\Delta S = (S_1 - S_2)/C_s$

Where: S_1 is the start of month storage volume:

S_2 is the end of month storage volume; and

C_s is a discharge to storage conversion factor based on the number of days in the month.

For the purpose of this study, base yield is defined as the minimum yield over a specified number of consecutive time intervals (months) that can be abstracted from the reservoir system fed by an inflow sequence while attempting to satisfy a target draft associated with a power demand pattern. The monthly water balance commenced with the reservoir being full and ended when it was empty and assumed a set of reservoir operating levels comprising a normal pool level (NPL) or full supply level and a maximum drawdown level (MDDL). An iterative process is applied to the water balance with the NPL value adjusted to yield a draft that delivers firm power over the year. Since firm power is constant the draft rate varies with the fluctuating hydraulic head on the turbines as reservoir level reduces.

2. Study Information, Data and Mapping

2.1 Reports and Data

Several documents, data, reports, and topographic mapping were used to assess the sites with potential storage to supply firm power for southern Labrador communities. These included, but may not have been limited to, the following:

- Coastal Labrador Phase 1: Advanced Screening, Final Report (August 2012).
- Site Flow Duration Curves (FDCs) developed for potential hydro sites studied in Phase 1 and used to estimate average annual energy from the sites and other power and energy variables. The FDCs were derived from simulated daily flows over the period 1979 to 2010.
- Phase 2: Project Definition Study of four shortlisted hydro sites (November 2012).
- Topographical Mapping at a scale of 1:50,000 with 10 m contour intervals, National Topographic System (NTS), Natural Resources Canada, 1999.
- Topographical mapping produced by AeroGeo with 2 m contour intervals.
- Load Forecast for Coastal Labrador communities. This was provided to Hatch by NLH for the Phase 1 and 2 studies and consisted of the long-term isolated system load forecasts for these communities covering the period 2013 to 2063 (50 years).
- Monthly load data for the four southern Labrador communities provided by NLH on February 24, 2013.
- Hourly load demand data for the Charlottetown community for a representative year provided by NLH on February 24, 2013.
- Canadian Climate Normals 1951-1980, Atmospheric Environment Services, Environment Canada, 1984.

2.2 Aerial Photographs and New Mapping

Aerial photographs were obtained through the Newfoundland and Labrador Provincial Aerial Photo Library. The highest quality photos available for each potential hydro site were obtained. The photo quality is summarized in Table 2-1 below.

Table 2-1: Aerial Photo Quality

Site Name	Aerial Photo Scale	Colour Quality
5	1:12,500	Colour
8	1:12,500	Colour
ALX	1:35,000	Black and White

During Phase 1 – Advanced Screening, digital mapping was developed for Site ALX using 1:12,500 scale colour photos. The coverage area was increased from 1.6 km^2 to 18.2 km^2 to capture the potential storage area upstream of the site. Approximately 2.5 km upstream of Site ALX, the mapping coverage area branches off to capture the Alexis River and a large south-north flowing tributary, and extends approximately 7.5 km upstream along both branches of the river. Consequently, additional photos from the 1:12,500 scale photo rolls used during Phase 1 did not completely overlap the required mapping area. The best available aerial photos that completely overlapped were 1:35,000 scale black and white photos and these were used.

Aero Geometrics Limited (AeroGeo) was contracted to generate digital mapping from the selected aerial photos. Using the 1:12,500 and 1:35,000 scale photos, AeroGeo was able to produce maps with 2 m interval contours lines for each of the sites. Typical estimated accuracies for aerial photogrammetric mapping based on photo scale and camera focal length are as follows:

Table 2-2: Typical Aerial Photogrammetric Accuracies

Photo Scale	Camera Focal Length	Contour Interval	Accuracy
1:10,000	152 mm	1 m	±0.25 m
	305 mm	2 m	±0.50 m
1:20,000	152 mm	2 m	±0.5 m
	305 mm	4 m	±1.0 m
1:50,000	152 mm	5 m	±1.25 m
	305 mm	10 m	±2.5 m

It is expected that there is some variance from the typical accuracies when using intermediate photo scales. It should be noted that in the absence of an accompanying ground survey to establish control points, contours generated through aerial photogrammetry cannot be exactly tied into the geodetic datum. Instead a “best guess” vertical datum is used to vertically position the contours as close to geodetic as possible; this was the case for Site 5B. For Sites 8 and ALX, AeroGeo was able to vertically position the new digital mapping using an area that overlapped the Phase 2 LiDAR contours. The accuracy of the contours is relative to the assumed datum and should not be referred to as the absolute accuracy (i.e. relative to geodetic datum).

AeroGeo also produced orthomosaics of the aerial photos. These are seemingly homogenous images composed of the individual aerial photos after they have been georeferenced (geographically positioned). Orthomosaics can be readily viewed in GIS programs alongside digital mapping to provide a comprehensive visual of the land coverage.

2.3 Hydrological Data

During Phase 2 a regional flow duration curve (FDC) methodology was selected as the best approach to synthesize the long term hydrology at the potential hydro sites. The results of the Phase 2 FDC analysis was carried forward as the hydrological input in this report. It should be noted that the physiographic parameters used to develop the FDC’s were

quantified during the initial stages of Phase 2. Iterative adjustments to the location of Site 8 have resulted in changes to the contributing drainage area. Typically each change in the location of Site 8 has been within 1 km of the preliminary location identified early in Phase 2. The exception is Site 8D which is approximately 5 km downstream of Site 8C. The location of site 8D translated into a 1.5% increase in the initial drainage area measured in Phase 2. It was decided that a 1.5% increase is small enough to have no meaningful impact on the resulting flows; therefore no adjustments were carried out on the mean daily flows developed in Phase 2.

A defining characteristic of the Labrador hydrology is the extreme variation in runoff between the seasons. The 1997 report *The Hydrology of Labrador* by the Water Resources Management Division (WRMD) determined that naturally flowing rivers in Labrador enter a recession phase when air temperatures drop below zero and a permanent snow cover is established. Hydrographs are typically in recession from December until April, however base flow recession can start as early as November and finish as late as May. The highest daily discharges are experienced in spring and are due mostly to snowmelt runoff. The spring flood accounts for a large portion of the total annual discharge. As an example, the mean date of maximum daily discharge based on 33 years of data for the Alexis River hydrometric gauge is May 17. Figure 2-1 below shows the average annual hydrograph for the Alexis River and the historical hydrographs for the 33 years of data.

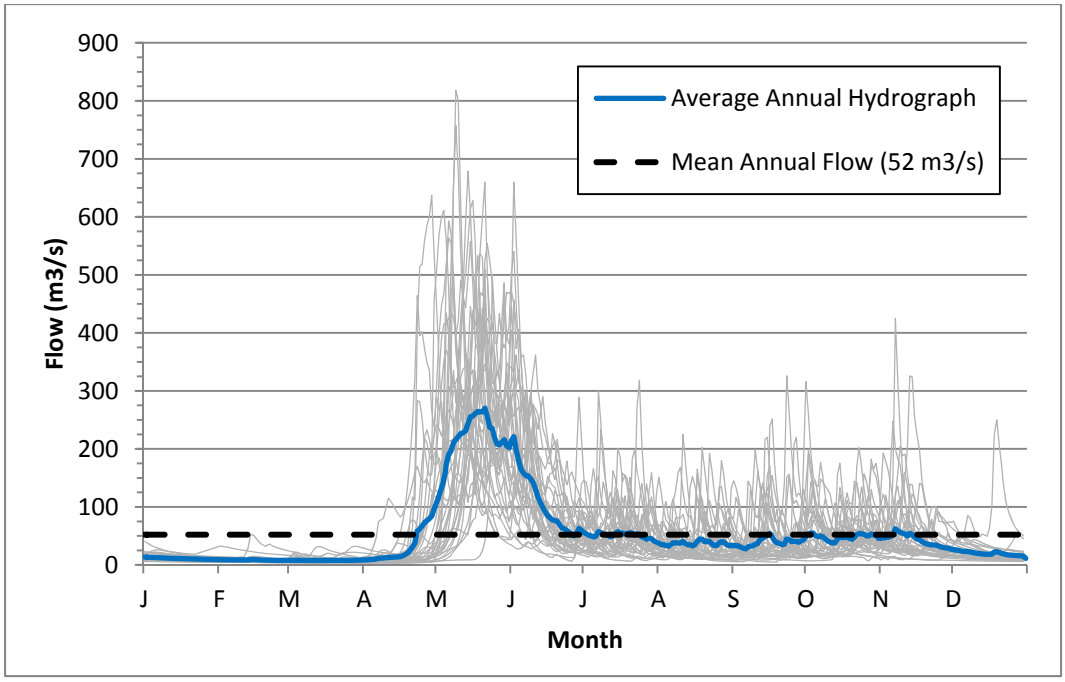


Figure 2-1: Alexis River Annual Hydrographs and Mean Annual Flow

A secondary peak is observed in early November and then the discharge steadily declines from late November to December and on through until the spring flood. The lowest daily discharges are experienced prior to the spring flood when temperatures are below freezing, precipitation is in the form of snowfall, and snow cover is near maximum. The mean date of minimum daily discharge for the Alexis River gauge is March 28.

This hydrograph distribution severely inhibits the ability of a run-of-river hydro generation facility to provide firm energy year-round. The natural solution would be to create a conservation storage that can impound some of the spring flood. The downstream hydrograph with a storage pond would flatten relative to the hydrograph in Figure 2-1. The maximum discharge in spring would be reduced and there would be a higher steady discharge in winter. The storage of peak flows in the conservation reservoir would provide the power draft during low inflow periods so that generation can meet demand year-round.

The 33-year hydrological sequence for the potential storage Site 5B was also examined for cyclicity by plotting a mass residual curve of synthesized mean daily flows (a cumulative mass plot of daily flows minus the long term mean daily flow at the site). Figure 2-2 shows the residual mass curve of the Gilbert River at Site 5B.

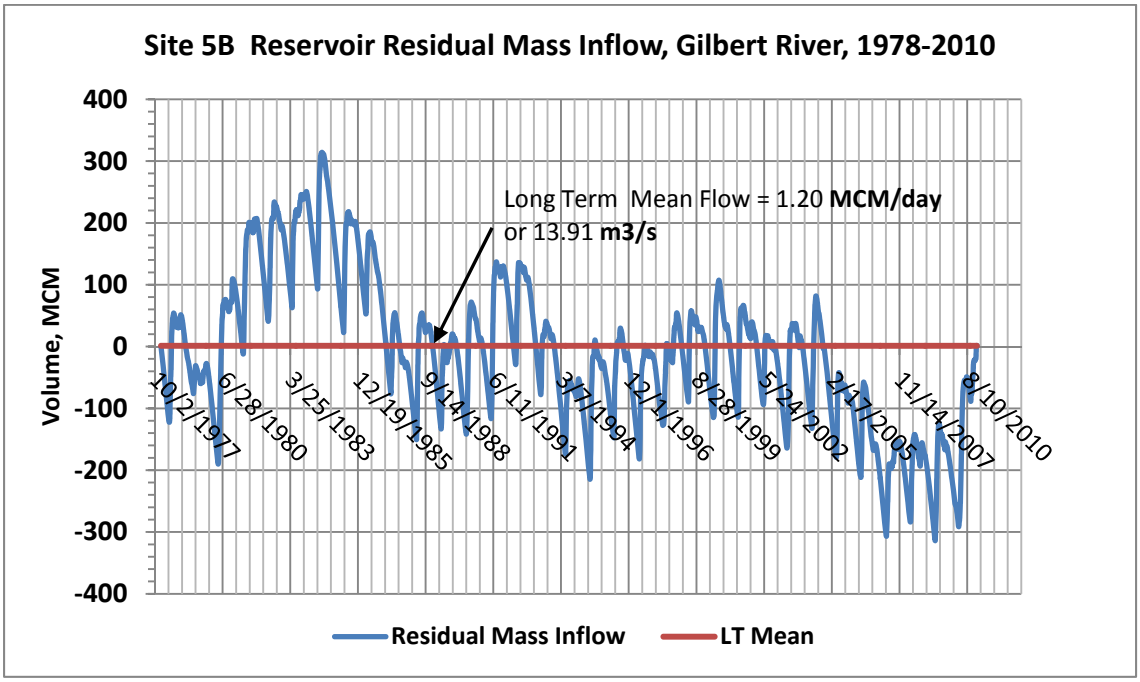


Figure 2-2: Residual Mass Curve, Site 5B

The conclusion from the residual mass curve plot is that there are more dry years than average or wet years of river flows in the 33-year record.

3. Load Forecasts and Demand

3.1 Load Forecast

The isolated system load forecasts for the southern communities were provided by NLH in Phase 2 of the study and covered the period 2012 to 2063. A planning horizon of 25 years was adopted and forecast peak capacity requirements at 2037 were abstracted from the data. These values were used to estimate the firm power requirements that would be delivered to the respective communities served by each site. The annual peak loads for each community are summarized below in Table 3-1.

Table 3-1: Annual Peak Loads by Community

Community	Peak Projected Load (2037)
Charlottetown	1848 kW
Port Hope Simpson	1198 kW
St. Lewis	300 kW
Mary's Harbour	1307 kW

3.2 Historical Load Demand Data

NLH also provided updated load pattern data for each of the four southern communities on February 24, 2013. The information consisted of total energy supply, peak monthly loads and average loads on a monthly basis, for a four year period from January, 2009 to December, 2012.

The load data was primarily used to determine the existing load pattern of each of the four communities. The monthly average of the four year period was used to represent the annual load distribution. It is assumed that for the purposes of this study, the demand load pattern will remain similar to what exists at present.

Table 3-2 summarizes the average annual demand for each community for 2009-2012.

Table 3-2: Average Monthly Demand by Community (2009-2012)

Month	MHS (kW)	CHT (kW)	PHS (kW)	STL (kW)
Jan	782	728	731	366
Feb	762	756	707	360
Mar	714	727	693	340
Apr	696	653	619	365
May	926	900	609	428
Jun	925	1287	602	426
Jul	866	1440	531	379
Aug	588	1368	545	287
Sep	665	1241	553	287
Oct	638	1163	580	317
Nov	731	769	651	331
Dec	832	734	725	357

3.3 Demand Load Curves

3.3.1 Annual Demand Load Curve

Since the demand load from the four communities varies from month to month, an annual load curve was used to represent the load in 2037. The load pattern is different for each community. For example, Charlottetown is characterized by a summer peaking pattern and Port Hope Simpson exhibits a winter demand peak.

As discussed in Section 3.2, the shape of a community's load curve was calculated based on the average monthly peak load from four years of data (2009-2012) and was assumed to be representative of a typical year. Each of the four load curves were normalized and prorated to the respective projected peak loads of 2037 for each community. The sum of the prorated load curves represents the total demand for the four communities in 2037 as displayed in Figure 3-1.

The aggregated load curve displays a summer peaking load pattern. The spike in load during the summer months is mainly driven by the operation of the fish processing plant in Charlottetown. The summer peaking load pattern is favourable for hydro power generation since the highest demand is concurrent with high river flows occurring during the spring and summer months.

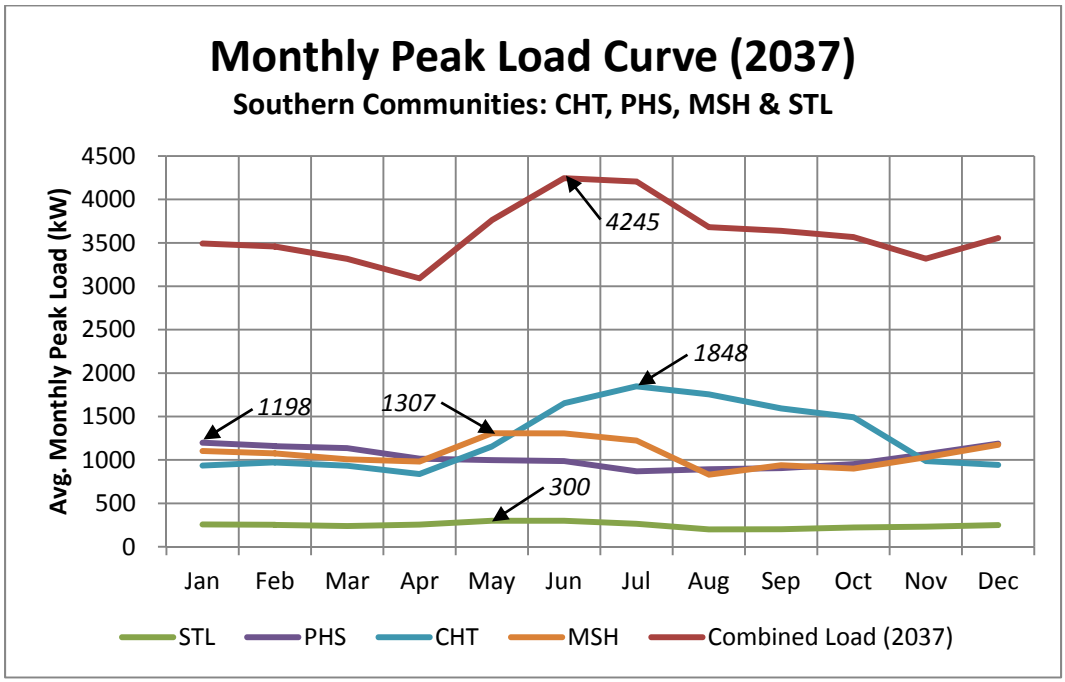


Figure 3-1: Projected Demand Curve for Communities of CHT, PHS, STL and MSH

Monthly energy was calculated as the product of the number of hours in each month and the corresponding projected peak load during that month. That is, it was assumed that the monthly peak load occurs for 24 hours each day. Annual energy was calculated as the sum of the monthly energy.

3.3.2 Monthly Load Curves

Raw load data was provided by NLH and consisted of intra-day load measurements for the Charlottetown community for the year 2009 taken at regular intervals. Typically, the load measurements were taken every few minutes at each generator. The load distribution is indicative of daily load demand trends and provides a pattern for each community's daily load requirements. Envelope curves were fitted over the historical daily data for the respective months to represent daily load curves for respective months and to match scheme generation and coincident community load pattern.

Intuitively, the peak daily load occurs during the afternoon and is lowest during the night. Figure 3-2 illustrates Charlottetown's envelope daily load pattern for the month of January, 2009. The envelope line on the graph encompasses the single day patterns of the month.

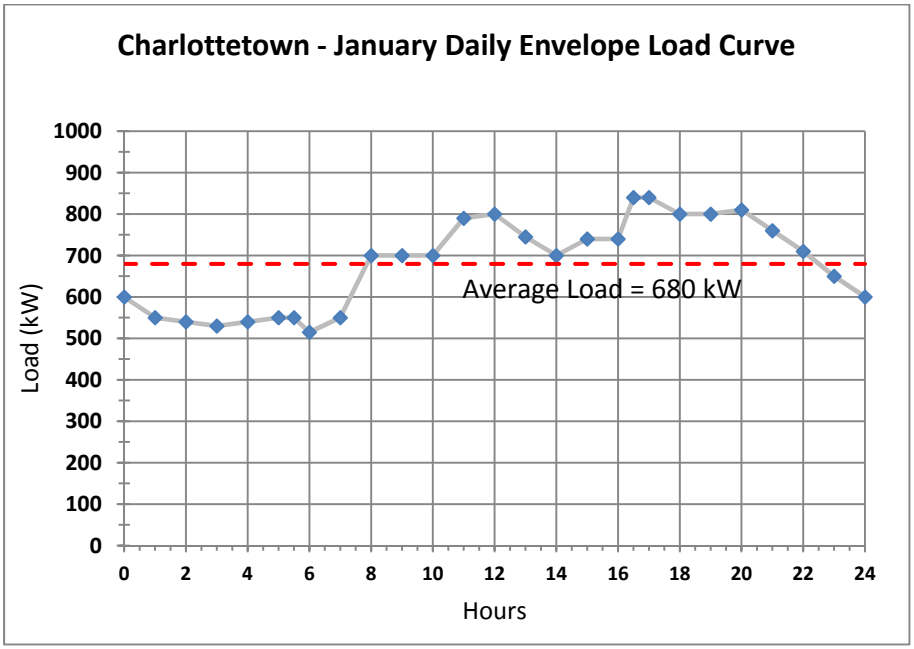


Figure 3-2: Envelope Daily Load Pattern at Charlottetown for January

The area under the daily load curve is the energy requirement delivered by the generating system. Figure 3.3 shows the same data portrayed as a load duration curve i.e., the percentage of time load exceeds a given value.

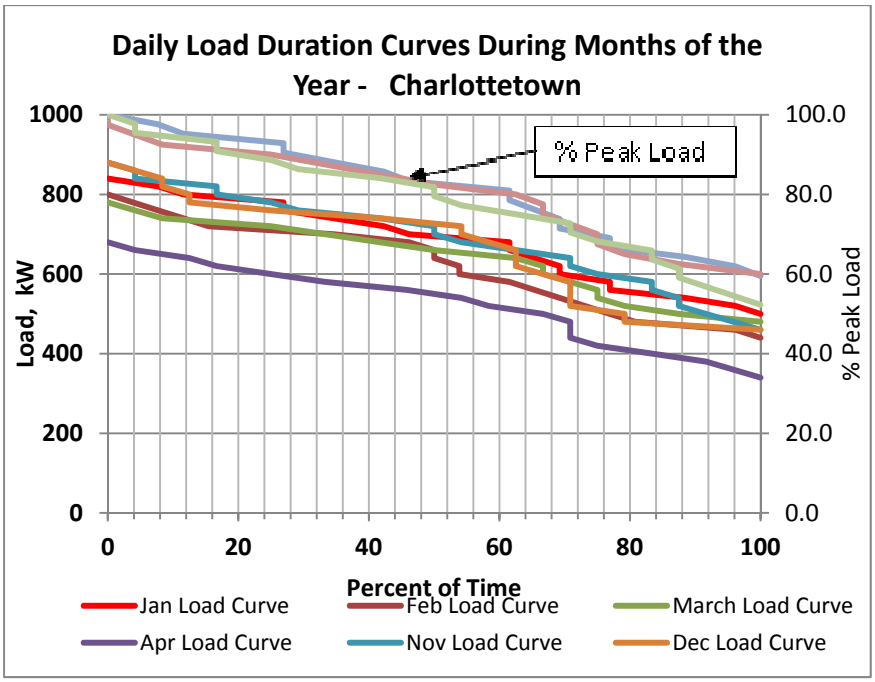


Figure 3-3: Load Duration Curves - Charlottetown

The daily load factors varied between 76.2% in December and 82.9% in March.

4. Description of Potential Storage Schemes – Generation Options

Descriptions of the potential hydro storage schemes evaluated under Generation Options #1 and #2 (as identified in Section 1.3.2) are presented in the following sections. A summary of the key technical details of these hydro schemes are given in Table 4-1.

4.1 Storage Site 5B

Site 5B is the re-designated storage hydro site from Site 5 and is located approximately 12 km due south of Charlottetown on the Gilbert River. It's forecasted load requirement in year 2037 is 1850 kW and is assumed to provide base load generation because of the isolated load centre. The proposed Site 5B dam site is approximately 300 m downstream of the Site 5 dam site.

Site 5 was on the shortlist of eleven run-of-river sites assessed during Phase 1 and the proposed plant installed capacity was 1860 kW with a net head of 20.85 m and a design flow of 10.2 m^3/s. Based on run-of-river generation for the site, the average annual energy was 10.17 GWh with a capacity factor (CF) of 63 percent. The full supply level was fixed at elevation 35.0 m with a top of dam elevation of 38.0 m and tailwater level (TWL) of 10.0 m. The total length of water conductors was 1,060 m and the layout incorporated a surge pond on account of anticipated surge pressures during load rejection.

The power and energy assessment from the run-of-river scheme indicated that it would be unable to deliver firm power and required supplementary flows during the low-flow period to meet power demand. Mean daily flow at the site is below 6.6 m^3/s for about 50 percent of the year and low-flow during the winter months approaches 1.5 m^3/s around the 90 percent exceedence level on the flow duration curve. Peak seasonal load would occur during winter and winter generation is therefore important for Charlottetown.

There is an existing head pond (named Gilbert Lake) of approximately 17 km^2 (pond area), located above the proposed dam location, with a pond elevation of 35 m, which drains into a smaller pond at elevation 30 m, which is adjacent to the proposed dam site. If the proposed dam is raised above the upper pond surface elevation then a substantial amount of storage would become available for generation by draft from the created conservation reservoir.

Table 4-1: Site and Plant Characteristics for Storage and Run-of-River Hydroelectric Developments

Description	5B-1 Option #1 a/	5B-2 Option #2 b/	8D Option #1	8C-2 c/ Option #2	ALX-B Option #1
Basin Characteristics					
River Basin Name	Gilbert R	Gilbert R	St. Lewis R	St. Lewis R	Alexis R
Communities served	CHT	CHT (plus PHS/MSH/STL)	PHS/MSH/STL	PHS/MSH/STL	PHS/MSH/STL
Basin Area, km^2	609	609	2397	2397	2312
Basin Hydrology					
Mean annual flow, m^3/s	13.5	13.5	61	61	52
Design flood (1:100 yrs), m^3/s	245	245	932	932	1198
Main Dam and Reservoir					
Type of dam	Embankment dam	Embankment dam	Embankment dam	Embankment dam	Embankment dam
Crest length, m	394	394	862	210	403
Crest elevation, m	40	40	42.5	38.5	81
Maximum dam height, m	22	22	43.5	23.5	39
Normal pool level (NPL), m	37	37.5	38.75	33.5	76.5
Maximum flood level, m	39	39.5	40.97	37.56	79.65
Maximum drawdown level (MDDL), m	32	32	26	-	64
Drawdown depth, m	5	5.5	12.75	0	12.5
Live storage, $x10^6$ m^3	104	116	33	Negligible	41
Flood Surcharge, $x10^6$ m^3	58	59	12	-	18
Spillway					
Type	Concrete overflow	Concrete overflow	Concrete overflow	Concrete overflow	Concrete overflow
Spillway width, m	35	35	90	60	85
Crest level, m	37	37.5	38.75	33.5	76.5
Intake					
Intake sill elevation, m	27.2	27.2	17.1	26.5	57
Opening width x height, m	6.6 x 3.0	6.6 x 3.0	3.0 x 2.6	4.0 x 4.0	4.0 x 4.0
Intake deck elevation, m	40	40	42.5	38.5	81
Water Conveyance System					
Length, m	1050	1050	100	60	1025
Diameter, m	2	2	1.8	2	2.4
No. of penstocks	1 (c/w bifurcation)	1 (c/w bifurcation)	2	2	1 (c/w bifurcation)
Powerhouse					
Type	Surface	Surface	Surface	Surface	Surface
Turbine type	d/ DR V. Kaplan	DR V. Kaplan	H. Francis	DR V. Kaplan	V. Francis
Number of units	2	2	2	2	2
Total installed capacity, kW	2,100	2,500	3,500	3,000	3,500
Gross head at rated flow, m	34.3	34.3	33.5	18	37.3
Net head at rated flow, m	32.4	31.4	32.5	17.5	35.11
Plant Rated flow, m^3/s	7.42	9.11	12.33	19.64	11.42
Tailwater level at rated flow, m	1.0	1.0	1.0	15.5	35.0
Plant efficiency, %	89	89	89	89	89
Community Peak Load (2037), kW	1,850	1,850	2,800	2,800	2,800
Firm power load, kW	1,850	2,300 e/	2,800	Variable	2,800

Notes:

a/ Site 5B-1 to serve CHT only; Site 8D or Site ALX-B to serve PHS/MSH/STL
b/ Site 5B-2 & Site 8C-2 to serve CHT/PHS/MSH/STL
c/ Run-of-river hydro scheme
d/ Double-regulated vertical Kaplan
e/ Surplus power over CHT demand goes into isolated grid serving CHT/PHS/MSH/STL

4.1.1 *Description of Project Features*

The general layout and sections of main elements of Site 5B storage scheme are denoted on the drawings in Attachment 2. The headworks will comprise a 394 m long embankment dam with a maximum height of 22 m. The top of dam elevation will be 40 m. The free-overflow spillway length required is 35 m. The power intake will be located on the right bank of the river and would consist of a 2.0 m diameter conduit with its invert at 27.2 m. The water conductor will extend over a distance of 1050 m terminating into a trifurcation at a surface powerhouse. Two branches will lead to the two turbine/generator units in the powerhouse while the third branch will be connected to a by-pass synchronous surge suppressor valve. Discharges from the powerhouse will flow into a rock-cut channel leading back to the river.

Technical details of the features of Site 5B are summarized in Table 4-1.

In the case of Option # 1 the scheme was sized to deliver a firm capacity of 1,850 kW dedicated to supplying Charlottetown only. The corresponding NPL of the reservoir was fixed at 37.0 m and a live storage volume of 104 million cubic meters (MCM). The powerhouse of the original Site 5 run-of-river hydro site has been re-located about 600 m downstream resulting in an increase of 10.5 m in potential hydraulic head for generation. The total length of water conveyance will be 1,050 m and based on the pipe length/ head ratio the scheme requires a surge suppression arrangement to handle load rejection and acceptance during operation. A surge suppressor synchronous valve (synchronized with the turbine governing) is proposed instead of a conventional surge tank. A separate valve chamber is located in the power house layout. Initially, two double-regulated vertical Kaplan turbines rated at 2100 kW are proposed in the powerhouse to deliver a firm power of 1,850 kW.

Under Generation Option #2 the NPL of the reservoir was set at elevation 37.5 m, and the firm capacity of the storage scheme was increased to 2,300 kW with a commensurate increase in plant installed capacity to 2,500 kW.

4.1.2 *Reservoir Storage Data*

The reservoir capacity and flooded area diagram for Site 5B is shown in Figure 4-1. Reservoir storage data for the two generation options are provided in Table 4-2.

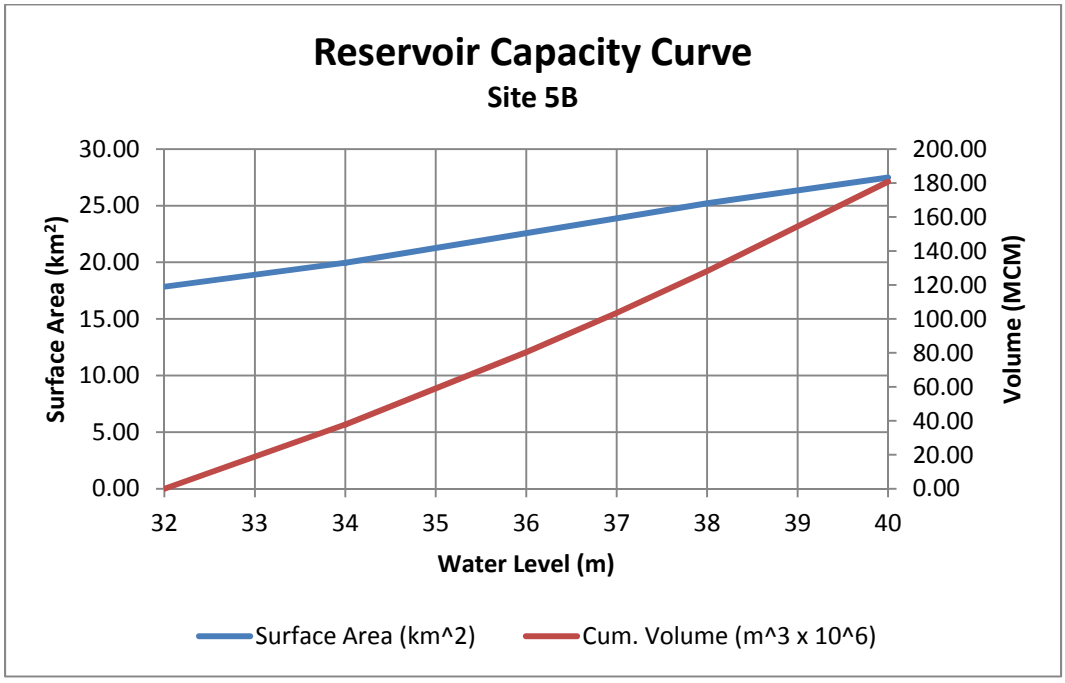


Figure 4-1: Site 5B Reservoir Capacity Curve

Table 4-2: Reservoir Storage Data for Site 5B

Reservoir Parameter	Option #1	Option #2
NPL (m) =	37.0	37.5
MDDL (m) =	32.0	32.0
Max. Flood Level (m) =	39.3	39.8
Live Storage (MCM) =	104	116
1/100 yr Flood Surcharge (MCM) =	58.4	59.5
Area at NPL (km^2) =	24	24.6

4.1.3 Hydraulic Data

Details of Site 5B hydraulic parameters are summarized in Table 4-1. The plant rated flow to generate 1,850 kW for Option #1 of power is 7.42 m^3/s. For power generation Option #2 at 2,300 kW firm power, the plant rated flow is 9.11 m^3/s.

4.1.4 Reservoir Yield Results

A water balance model was established for Site 5B to determine the reservoir yield and its draw-down trajectory during the driest period. The critical dry period of 1986/87 was used for all sites as it exhibits the lowest total annual flow of the 33 years of available flow data. Based on the results of the water balance with a normal pool level (NPL) of 37.5 m and live storage of 116 MCM, firm power of 2,300 kW could be generated for the entire year without the reservoir falling below the selected MDDL of 32.0 m. In the case of a NPL of 37.0 m and a live storage of 104 MCM the draft rates from the reservoir allow generation of only 1850 kW of firm power.

The reservoir trajectory over the critical dry year 1986/87 is shown in Figure 4-2 as well as the inflows and power flows. Storage is seasonal with the reservoir filled during the spring floods in April and May and is drawn down as the power flow exceeds inflow in the July/August period. The low inflow during the winter months from December to March is supplemented by draft from available storage until April when spring floods replenish the reservoir.

The base case simulations for both generation options indicate that the selected reservoir operating pool levels result in acceptable reservoir yields at the 3% level. Drafts can be relied upon 97% of the time. Firm power of 2,300 kW was generated in all months for the NPL of 37.5 m. A similar result was obtained for a firm power of 1,850 kW with a NPL of 37.0 m. No non-power withdrawals from the reservoir were included in the simulations at this time. When these are quantified during the next phase of engineering, a new set of simulations with changed operating pool levels will be necessary and may require a change in dam height. Operation of Site 5B as a storage reservoir for hydro generation of firm power is therefore technically viable despite the low flows available during the winter months.

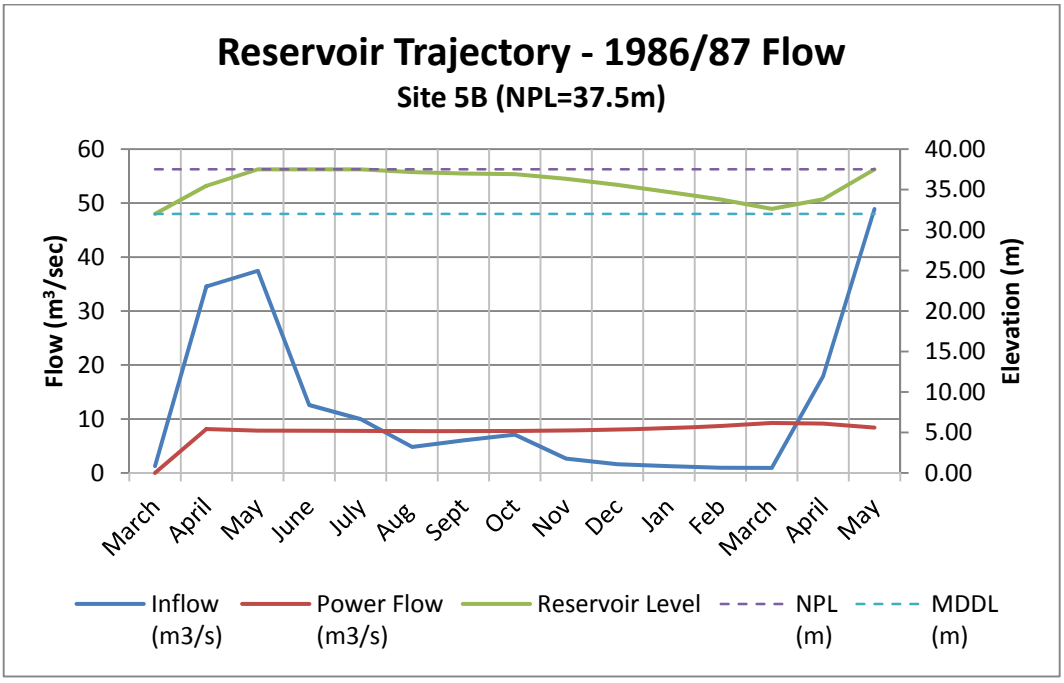


Figure 4-2: Site 5B Reservoir Trajectory in Critical Dry Year and Flow Hydrographs

4.2 Potential Storage Site 8D

Site 8D is evaluated as a potential storage hydro project on the St. Lewis River to serve the communities of PHS/MSH/STL that have a forecasted load demand of 2,800 kW under Generation Option #1. In order to create a sufficiently large storage reservoir in the river valley, it is proposed to have a high dam (greater than 40 m) relocated as far downstream on the St. Lewis River as possible, now designated Site 8D. Although Site 8D is approximately 5 km downstream of Site 8C, its drainage area only increases marginally. The FDC calculated for Site 8C was therefore assumed to be applicable for Site 8D. A dam across the river valley at the proposed location will be about 860 m in length.

4.2.1 Description of Project Features

The general layout and sections of main elements of Site 8D storage scheme are shown in Attachment 2. The headworks would comprise a 862 m long embankment dam with a maximum height of 43.5 m. The top of dam crest elevation will be 42.5 m. The free-overflow spillway length required is 90 m to pass the 1 in 100-year flood of 932 m^3/s. Technical details of the scheme are summarized in Table 4-1.

A close-coupled powerhouse with short water conveyance is envisaged for the generation facility and estimated rated net head is 32.5 m. The revised design flow for an installed capacity of about 3,500 kW is estimated to be 12.3 m^3/s. Since the forecasted load requirement in 2037 for PHS/MSH/STL is about 2800 kW, the firm capacity to be delivered from Site 8D would also be 2,800 kW. The hydro plant will consist of two double regulated Kaplan turbine units. The units will have the above rated head in order to operate at the selected reservoir pool levels.

The spillway crest elevation will be at elevation 38.75 m and for the 1 in 100-year flood, the high flood level in the reservoir would be 41.70 m. The 90 m wide spillway will be located on the right bank. The surface powerhouse will be located at the downstream face of the dam but will require excavation of a 230 m long tailrace channel to the main river channel. A fish ladder is proposed on the left bank of the river.

4.2.2 Reservoir Storage Data

The elevation/volume and flooded area curves for the reservoir created by a dam at site 8D is shown in Figure 4-3. The selected normal pool level for the reservoir is 38.75 m and assuming a minimum draw down level of 26.0 m, the reservoir draw down depth is 12.75 m; mean reservoir level would be at 32.38 m. The gross and net rated heads were fixed at 33.50 m and 32.50 m, respectively. The TWL at the dam site is estimated to be about 1.0 m giving a gross head of 31.38 m at mean reservoir level.

Based on the selected operating reservoir levels for Site 8D and assuming a variable draft from 8.97 m^3/s to 14.5 m^3/s, the total annual live storage required would be 15.3 MCM, including an amount for evaporation losses. The available storage in the created reservoir between elevations 38.75 m and 26 m is 33 MCM indicating a surplus storage of 17.7 MCM. Withdrawals from the reservoir will occur over approximately 70 days annually in an average climatic year.

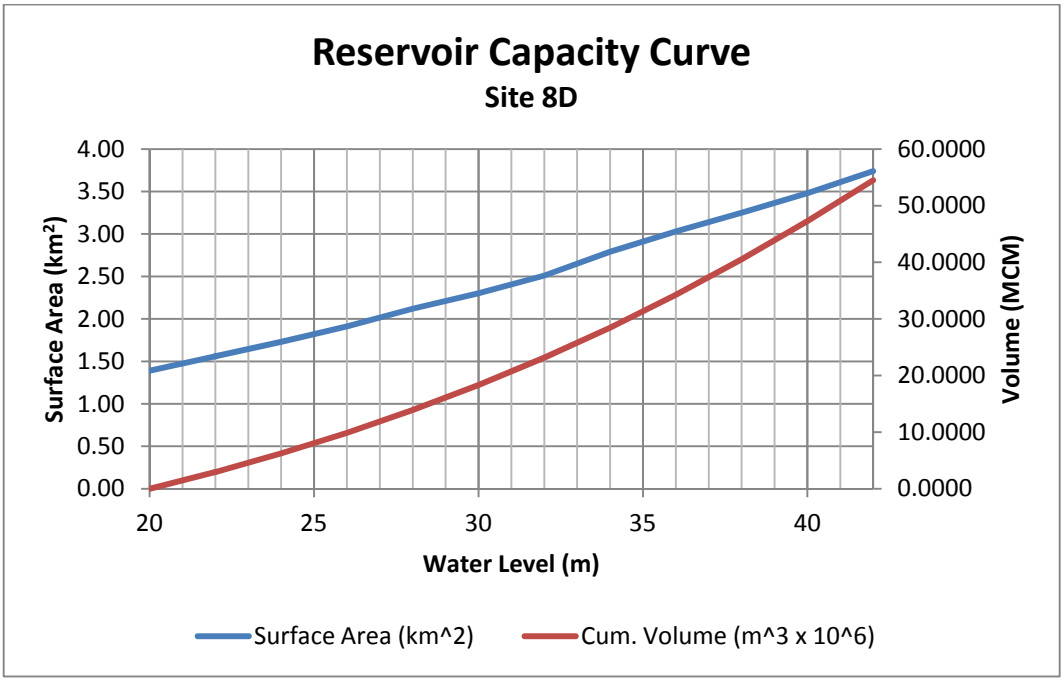


Figure 4-3: Site 8D Reservoir Capacity Curve

Reservoir storage parameters for Site 8D are shown below in Table 4-3.

Table 4-3: Reservoir Storage Data for Site 8D

Site 8D Reservoir Parameters	
NPL (m) =	38.75
MDDL (m) =	26
Max. Flood Level (m) =	41.7
Live Storage (MCM) =	33
1/100 yr Flood Surcharge (MCM) =	12
Area at NPL(km^2) =	3.3

4.2.3 *Hydraulic Data*

Details of Site 8D hydraulic parameters are summarized in Table 4-1. The plant rated flow to generate 2,800 kW of power is 12.33 m^3/s.

4.2.4 *Reservoir Yield Results*

A water balance model was used to simulate reservoir operations during the driest period of the flow sequence for the site The study period of 1986/87 was used for all sites as it exhibits the lowest total annual inflow of the 33 years of available flow data. Based on a selected normal pool level (NPL) of 38.75 m a small load deficit of 122 kW occurred in March of the critical year. The actual reservoir simulation verified that the initial storage surplus estimated was not really a surplus. If the reservoir NPL is raised to 39.0 m to increase the live storage, firm power of 2,800 kW can be generated over the entire period.

The reservoir inflows, power flows and trajectory are shown in Figure 4-4 and highlights the necessity for storage due to the seasonal variation of inflow. The reservoir is filled during the spring floods in April and is drawn down as the power flow exceeds inflow in the winter. The low inflow during the winter months from December to March is supplemented by the available storage.

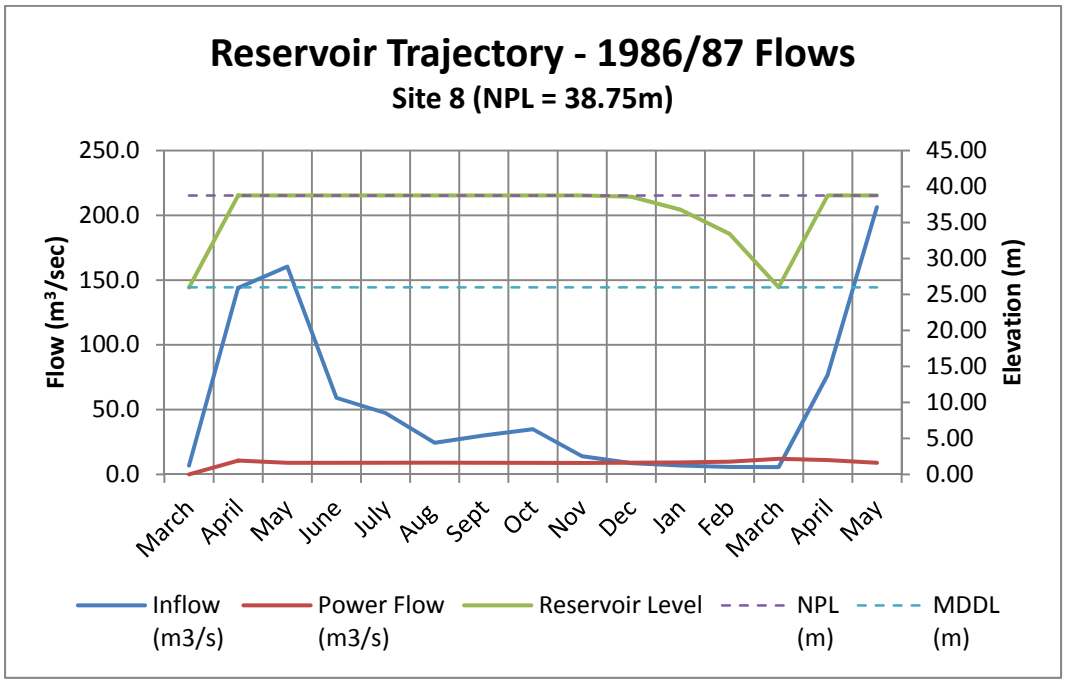


Figure 4-4: Site 8D Water Balance Variables and Reservoir Trajectory

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4.3 Potential Storage Site ALX-B

Site ALX is situated on the Alexis River at a 9 m high falls. The site is an attractive run of river scheme due to the existing natural head and significant summer flows; however, there is no available storage. Consequently, the large volume of river flow during spring runoff is primarily spilled and cannot be used for generation.

Site ALX (in the Phase 2 main report) has an installed capacity of 4400 kW to service the three southern communities of CHT/PHS/MSH, with a net head of 8.75 m. The capacity factor of Site ALX is 47% and on average, the scheme satisfies approximately 56% of the projected demand energy.

On account of the large seasonal variance of the Alexis River flows, a site with significant storage capacity is desirable. In its current location, Site ALX does not lend itself to storage without the construction of an unreasonably long dam. An alternate site, termed Site ALX-B, is located approximately 900 m upstream of Site ALX and is situated in a location more conducive to a storage reservoir.

Site ALX-B is located in a river valley approximately 50 m wide, with banks approximately 40m high. The relatively narrow width of the valley limits the cost of the diversion dam. Moreover, a bend in the river and a plateau on the left bank of the valley provides a natural location for the overflow spillway.

Upstream of Site ALX-B, the topography of the land levels out and the river splits in two. This natural feature of the upstream terrain is desirable for a large storage reservoir as it provides significant surface area for flooding. Although no natural storage exists, the headpond created by a large dam would satisfy the storage requirement of 41 MCM.

Site ALX-B would service the communities of PHS/MSH/STL with a total peak demand load of approximately 2800 kW, under Generation Option #1.

4.3.1 Description of Project Features

The general layout and sections of main elements of Site ALX-B storage scheme are detailed in Attachment 2. The headworks would comprise a 403 m long embankment dam with a maximum height of 39.0 m. The top of dam elevation will be 81.0 m. The free-overflow spillway length required is 85.0 m to pass the 1 in 100-year flood of 1198 m^3/s. Technical details of the scheme are summarized in Table 4-1.

The Site ALX-B powerhouse is located near the pool at the base of the falls approximately 1 km downstream of the headworks. This arrangement requires a long water conveyance from the intake to the powerhouse. The water conveyance system consists of one 2.4 m penstock which bifurcates at the powerhouse for the two units. The total length of the penstock from the intake to the powerhouse is approximately 1025 m in length. A surge chamber is located upstream of the powerhouse and branches off of the penstock. The surge chamber is required for surge suppression during load rejection purposes.

The gross head of Site ALX-B is 37.33 m with an estimated net head of 35.11 m. The powerhouse consists of two 1750 kW double regulated vertical Kaplan turbines for a total installed capacity of 3500 kW. Based on the operating levels of the headpond, the arrangement will provide 2800 kW of firm power for the three southern Labrador communities. The plant rated flow of the scheme is 11.42 m^3/sec.

The spillway crest elevation will be at elevation 76.5 m and for the 1 in 100-year flood the high flood level in the reservoir would be 80.2 m. The 85 m wide spillway will be located on the left bank. The spillway will be located in an existing bend in the river and will facilitate discharge as it directs flow along the natural alignment of the river.

The surface powerhouse will be located at the pool below the falls. The powerhouse is located adjacent to the pool, hence, only a minor amount of tailrace excavation is required. A fish ladder is proposed on the right bank of the river.

4.3.2 Reservoir Storage Data

The elevation/volume and flooded area curves for the reservoir created by a dam at site ALX-B is shown in Figure 4-5. The selected normal pool level for the reservoir is 76.5 m and assuming a minimum draw down level of 64.0 m, the reservoir draw down depth is 12.5 m; mean reservoir level would be at 70.25 m. The gross and net rated heads were fixed at 37.33 m and 35.11 m, respectively. The TWL at the dam site is estimated to be about 35.0 m giving a gross head of 35.25 m at mean reservoir level.

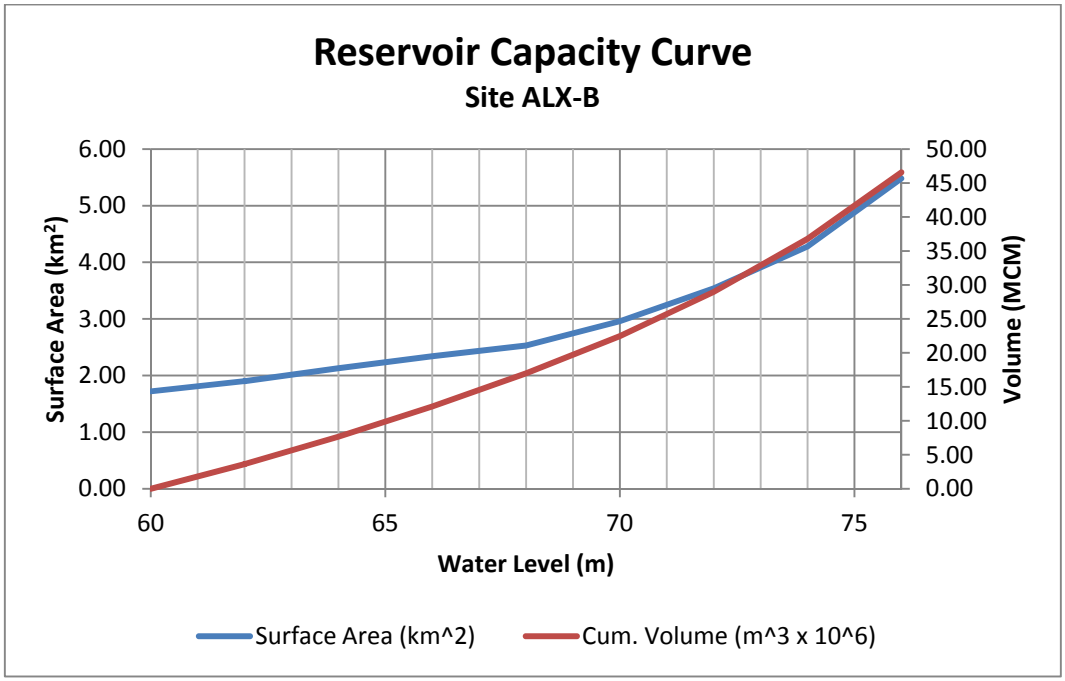


Figure 4-5: Site ALX-B Reservoir Capacity Curve

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Reservoir storage parameters for Site ALX-B are shown in Table 4-4.

Table 4-4: Reservoir Storage Data for Site ALX-B

Site 8D Reservoir Parameters	
NPL (m) =	76.5
MDDL (m) =	64.0
Max. Flood Level (m) =	80.2
Live Storage (MCM) =	41
1/100 yr Flood Surcharge (MCM) =	18
Area at NPL(km^2) =	6

4.3.3 Hydraulic Data

Details of Site ALX-B hydraulic parameters are summarized in Table 4-1. The plant rated flow is 11.42 m^3/s.

4.3.4 Reservoir Yield Results

A water balance model was established for Site ALX-B to determine the reservoir trajectory during the driest period. It was determined that with a normal pool level (NPL) of 76.5 m firm power of 2800 kW is achieved for the entire period. That is, the reservoir is not completely exhausted and 2800 kW of power is produced every day for each month.

The reservoir trajectory is shown in Figure 4-6 and highlights the necessity for storage due to the seasonal variation of inflow. The reservoir is filled during the spring floods in April and is drawn down as the power flow exceeds inflow in the winter. The low inflow during the winter months from December to March is supplemented by the available storage.

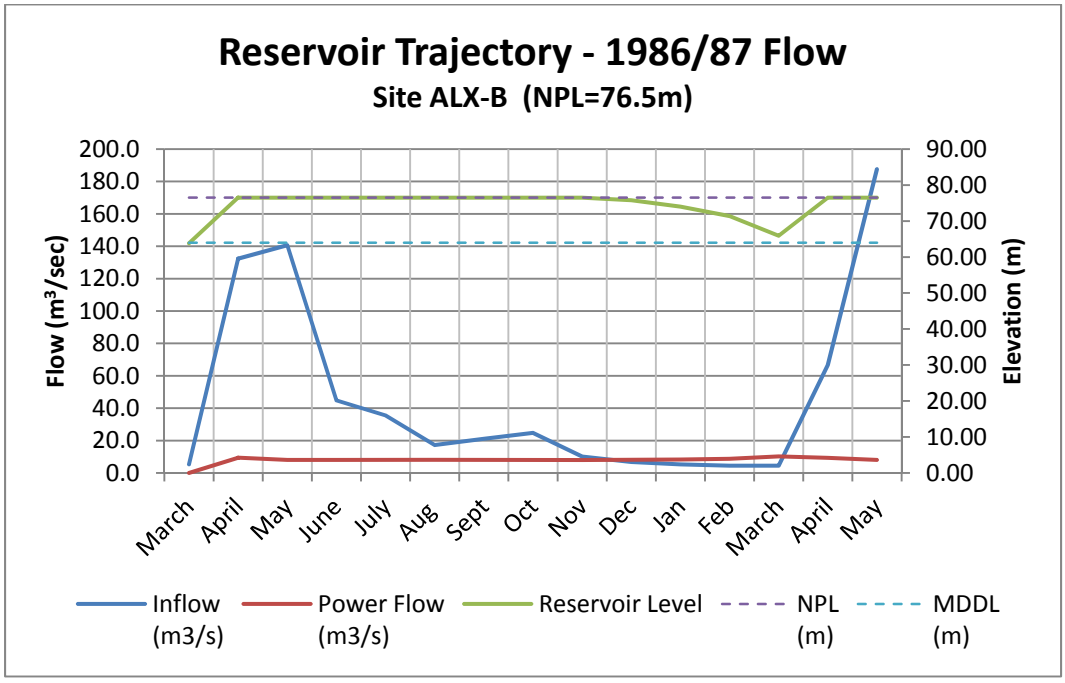


Figure 4-6: Site ALX-B Reservoir Trajectory

4.4 Run-of-River Site 8C-2

Site 8C-2 is the re-designated (lower installed capacity than Site 8C) run-of-river hydro site from original Site 8C, located approximately 11 km due south of Port Hope Simpson on the St. Lewis River. The installed capacity of original Site 8C was 4400 kW and would service the three southern Labrador communities of CHT/PHS/MSH.

Site 8C was on the shortlist of 4 sites during Phase 2 and the proposed plant installed capacity was 4400 kW with a net head of 17 m and a design flow of 29.7 m^3/s. Based on a run-of-river generation for the site, the average annual energy was 28.54 GWh with a capacity factor (CF) of 74 percent. The full supply level was fixed at elevation 33.5 m with a top of dam elevation of 38.5 m and tailwater level (TWL) of 15.5 m. The total length of water conductors was 60 m.

The power and energy assessment from the run-of-river scheme indicated that it would be unable to deliver firm power and required supplementary flows during the low-flow period to meet power demand.

Site 8C is located in the St. Lewis River valley at a location with steep, high banks. The natural terrain is not favourable for a large storage reservoir due to the shape of the river valley. That is, a very high dam is necessary to generate a sizeable volume of storage, and, the reservoir created by such a high dam would flood the upstream falls (original Site 9) and existing tourist/fishing lodge.

Due to the variability of the St. Lewis River flows throughout the year, energy shortfalls exist and primarily occur during winter months. Site 8C-2 is intended to be operated alongside Site 5B (2300 kW) to satisfy the demand of the four southern Labrador communities of CHT/PHS/MSH/STL. The aggregate demand curve of the four communities displays a summer peaking trend. Hence base loading would be provided by Site 5B (2300 kW) for the entire year and would be supplemented by Site 8C-2 for summer peaking.

Since Site 8C-2 is intended to supplement Site 5B (2300 kW), the power deficit dictates the installed capacity of Site 8C-2. It was determined that Site 8C-2 should have an installed capacity of 3000 kW to provide firm power (combined with Site 5B) for the four southern Labrador communities.

4.4.1 Description of Project Features

The general layout and sections of main elements of Site 8C-2 storage scheme is denoted in Attachment 2. The headworks will comprise a 210 m long embankment dam with a maximum height of 23.5 m. The top of dam elevation will be 38.5 m. The free-overflow spillway length required is 60 m. The power intake will be located on the left bank of the river and consist of two, 2.0 m diameter penstocks with their inverts at 26.5 m. The two penstocks will lead to the turbine/generator units in the powerhouse. The powerhouse is adjacent to the river and discharges will flow through a small rock cut channel and back into the river.

Technical details of the scheme elements are summarized in Table 4-1.

Under Generation Option #2 the scheme was sized at a total installed capacity of 3000 kW, in order to deliver sufficient firm capacity to provide power to the four southern Labrador communities in a grid with Site 5B. The corresponding FSL of the reservoir was fixed at 33.5 m with no appreciable volume of storage. As the penstocks are relatively short, no surge suppression system is required. Two double-regulated vertical Kaplan turbines rated at 1500 kW are proposed in the powerhouse.

4.4.2 Hydraulic Data

Details of Site 8C-2 hydraulic parameters are summarized in Table 4-1. The plant rated flow to generate 3000 kW of power is 19.64 m^3/s at FSL.

4.5 Mechanical/Electrical Equipment

The installed capacity, firm capacity, rated net head and rated flow data for potential storage/run-of-river hydro projects for the four Coastal Labrador towns are as summarized in Table 4-5 below.

Table 4-5: Main Features of Generation Options #1 and #2

Description	Site #	Coastal Labrador Town	Type of Facility	Installed Capacity (kW)	Firm Capacity (kW)	No. of Units	Rated Net Head (m)	Plant Rated Flow (m^3/s)
Generation Option 1 2 sites serving Isolated Grid to each community (5B+8D or 5B+ALX-B)	5B-1	CHT	Storage	2250	1850	2	32.4	7.42
	8D	PHS/MSH/STL	Storage	3500	2800	2	32.5	12.33
	ALX-B	PHS/MSH/STL	Storage	3500	2800	2	35.1	11.42
Generation Option 2	5B-2	CHT	Storage	2500	2300	2	31.4	9.11
2 sites serving Isolated Grid serving all communities (5B+8C-2)	8C-2	PHS/MSH/STL	Run-of-river	3000	Varies	2	17.5	19.64

4.5.1 Turbines and Generators

4.5.1.1 Turbines

The desirable feature for the selection of the type of turbine for the five sites is to provide a turbine setting above tail water level (TWL) to enable location of all powerhouse equipment above TWL and eliminate the risk of flooding in powerhouse.

The rated net head at three sites under Generation Option 1 (5B, 8D, ALX-B) and one site under Generation Option 2 (5B) range from approximately 31 to 35 m and unit generator output ranges from 1125 to 1750 kW. A Francis or a conventional Kaplan type turbine (with cylindrical distributor and scroll casing) are suitable for this range of output and head range. Axial flow type turbines with their characteristic conical distributor such as Saxo, or Horizontal S type, Horizontal upstream elbow are used for heads up to 30 m only, hence these types of turbines have not been considered. For Site 8C-2, conventional Kaplan or axial flow type turbines will be suitable.

Ossberger (horizontal cross flow) type turbines are also suitable for all the sites; however, the turbine efficiency is 4 to 5% lower for an Ossberger than for Kaplan and Francis turbines. Nevertheless, the merits of relatively flat efficiency and lower turbine-generator cost (based

on the budgetary proposals for Ossberger turbines received for Phase 1 and 2 studies) may present a good potential for consideration during the design phase.

The installed capacities at all five sites under Option 1 and 2 are with 2 units each. A two unit configuration ensures a minimum availability of 50% installed capacity, whereas a three unit configuration with 150% installed capacity will ensure 100% availability of the firm capacity to meet the requirement of complete displacement of diesel generation.

For the storage schemes with regulated flows, the head and flow variation are expected to be much less compared to a run-of-river scheme. The head and flow variation for the storage Sites (5B, 8D, ALX-B) could be within ± 10% of rated conditions whereas for the run-of-river Site (8C-2) the minimum turbine flow can be 20 to 25% of the rated flow. Accordingly for the storage schemes a Francis or a fixed blade propeller will be applicable, whereas for the run-of-river scheme a full Kaplan will be required.

The choice between a Francis and Kaplan propeller type of turbine will be based on the overall cost (best value) of the turbine-generator unit. For the storage sites, for the given range of heads and unit outputs, the anticipated synchronous speeds for a Francis turbine will be lower than a Kaplan turbine, whereas for a given runner size a Kaplan will cost more than Francis. Further, vertical turbines generally cost more than horizontal turbines. The type and configuration of the turbine for the selected sites with the most economical solution can be decided in consultation with W2W suppliers during the next engineering phase.

The configuration of the turbine-generating unit can be vertical or horizontal. A vertical arrangement provides a smaller powerhouse footprint whereas a horizontal arrangement provides ready access to all the equipment for inspection and maintenance. A small horizontal Francis turbine is commonly designed with its runner mounted on the generator shaft extension resulting in a compact arrangement.

Considering the above, the general arrangement drawings of the powerhouse for the five sites with vertical or horizontal/Francis or Kaplan turbines are representative of the type and arrangement of turbines that are suitable for the sites.

4.5.1.2 Turbine Inlet Valves

All the sites under Generation Options 1 and 2 feature penstocks to convey water to the turbines. Site 8C-2 and 8D have dedicated penstocks whereas the remaining three sites (5B - Option 1, ALX-B, 5B - Option 2) feature a common penstock and a bifurcation at the powerhouse to 2 unit penstocks. The sites with common penstock will necessarily have a turbine inlet valve at the inlet to each turbine for isolating the turbine when not in operation and also provide back-up emergency closure to the wicket gates. The valves will be connected to the steel spiral with a dismantling joint on downstream and a suitable make up piece on the upstream for welding to the penstock. The valves will be designed to close under maximum head and runaway flow with weight closure and a hydraulic operator.

4.5.1.3 *Turbine Controls*

A full featured digital governor is required to provide frequency control with power feed-back control and regulate the turbine. For island mode operation, the powerhouse will require black start capability to open the turbine inlet valves and crack open the wicket gates in order to start the turbines and synchronize the units. The black start capability may include DC motors with battery power or separate emergency diesel generator set.

4.5.1.4 *Governing Stability*

5B - Option 1 and 5B - Option 2 have very long penstocks with length of penstock/rated head (L/H) > 30. A synchronous turbine bypass valve/pressure relief valve is proposed to relieve the penstock pressures on load rejection and assist in providing stable governing. The check for governing stability in conjunction with associated turbine-generator rotating mass, water conveyance system and governor closing time etc, for the selected site/s will be the subject of detailed study at a later stage. The L/H ratio for the remaining sites is between 3 and 3.6, and are not likely to pose issues with stability.

4.5.1.5 *Generators*

The present preliminary design anticipates synchronous type generators, with a shaft mounted brushless excitation system. The power source for the pilot exciter could be derived from a shaft mounted permanent magnet generator or from the station auxiliary supply depending on operational needs.

The automatic voltage regulator, pilot exciter and exciter will need to be responsive to the load swings of this island system and provide sufficient field forcing to prevent voltage droop during these events.

The present configuration assumes a brushless excitation system but future system design may impose usage of a fast response static excitation system to improve isolated grid stability.

Selection of the generator and the turbine will need to address the inertia of the rotating assemblies and the response of the governor systems to optimize operation in the islanding mode where large sudden load steps or load rejection may result in frequency excursions. The governor will have to be selected to have stable isochronous operation for this islanded system. This will require a system study to define details.

Synchronous generation was selected because of its ability to provide the reactive power required to operate this islanded grid distribution system. A possible alternative to this traditional approach for small hydro power plant design may be a combination of permanent magnet generators and electronic AC-DC-AC converters. This alternative can be investigated with prospective vendors in the next phase of this project with close attention paid to the reactive power requirements of the network.

4.5.2 Powerhouse Electrical and Mechanical Auxiliaries

4.5.2.1 Mechanical

The powerhouse mechanical auxiliaries will include hydraulic power units for turbine and inlet valves, cooling water supply system for shaft seal, and, if required for bearing cooling, compressed air system for generator brake and service air, head cover drainage pumps, drainage system with oil water separator, dewatering system, heating and ventilation system, fire protection system, piping systems for oil, water and air including piezometer piping.

4.5.2.2 Electrical

The powerhouse electrical systems will include PLC based turbine controls and monitoring equipment, generator condition monitoring equipment, MV switchgear, unit and plant control, protection, metering and SCADA systems, station service transformers, LV power, control, protection, DC supply system with batteries and charger, switchyard equipment.

4.5.2.3 Powerhouse Crane

Considering the remote location of the sites, an electrically operated bridge type overhead travelling crane is recommended for unloading of powerhouse equipment in the service bay, installing the turbines, generators and all associated equipment and for routine maintenance thereafter.

4.5.3 Powerhouse Electromechanical Equipment

The inclined trash racks located at the entrance to the intake will prevent any floating debris and ice from entering the conveyance channel and ultimately into the turbine. The minimum trashrack bar spacing will be governed by the turbine requirements.

With turbine inlet valves provided for the sites with common penstock, a bulkhead gate/stoplogs will be required to drain the penstock and or inspection servicing of the inlet valve. For the sites with dedicated penstocks, the option to provide a turbine inlet valve or a vertical wheeled emergency closure gate at intake may be decided based on cost. In either case a bulkhead/stop log will be required at the intake for the inspection/servicing of valve/intake gate. The intake gate can be operated by an elevated/deck mounted wire rope hoist/hydraulic cylinder/screw stem hoist. The upstream service gate can be a set of stop logs or a sectional/single leaf bulkhead.

A sectional/single leaf bulkhead gate is proposed on the draft tube for dewatering the turbine and to provide access to the turbine runner for inspection and maintenance.

Considering the remote location of the sites, use of a mono rail hoists for the installation and operation of the intake service gates and draft tube gates may be considered.

4.6 Local Grid and Transmission Lines

The preferred hydro power development for feeding the communities of Charlottetown, Port Hope Simpson, Mary's Harbour and St. Lewis includes one storage facility at Site 5B and one run-of-river plant at site 8C-2, both to be developed to form an isolated grid with an interconnecting transmission line approximately 110 km in total length.

The present assumption is that the existing diesel plants at Charlottetown, Port Hope Simpson, Mary's Harbour and St. Lewis will be decommissioned or partly decommissioned with potentially a minimal capacity still left in service at one town or at each town to serve as local emergency backup supply and will not be used to supply power to other towns via the proposed interconnecting lines.

The interconnecting line has been illustrated on the single line drawing in Attachment 2. The 34.5 kV level is not a standard distribution voltage in the province of province of Newfoundland and Labrador, however in this particular installation it was identified that the interconnecting will be 110+ km long and for that reason a standard distribution line voltage of 25 kV may not be suitable.

The 34.5 kV level is provisionally selected as the highest design voltage for which the equipment is still widely available in North America. The final selection of voltage can be evaluated technically and commercially during the detailed design phase of this project.

At the hydro power plant (HPP) locations, the transformer, 34.5kV primary breaker, line isolating motorized disconnect and surge arrestors will be mounted in a fenced substation exterior to the hydro power plant.

At each town substation, and since the existing community distribution is dependent on single phase-to-neutral loads, there will be a requirement that new hydro sources establish a ground point near the exiting town site. This will require a grounded wye, isolating transformer at the town-site or a step-up transformer at the hydro plants and a step-down transformer at the town-site.

Due to the length of lines and distributed loads as shown on the SLD, there may be a requirement for additional voltage support at the various communities or at one central place (Port Hope Simpson is suggested) in the form of capacitor banks. System modeling in the detailed phase of engineering will confirm this requirement.

Provisional interconnecting line lengths are shown on the SLD. The distribution line has been assumed as an overhead line with 477 KCMIL conductors. A single circuit overhead distribution line is anticipated sharing the poles with a fiber optic cable communications link to interconnect the hydro power plants and town substations for the purpose SCADA and any tele-protection requirements. As an alternative, a two circuit line can be considered to improve reliability in which case circuit conductor size can be smaller than for the single circuit scenario.

As this distribution system will feed multiple customers, it requires some configurability for minimizing the impacts of maintenance and restoration in emergency situations. A series of sectionalizing switches have been located along the line allowing individual towns to be isolated and hydro power to be restored (or maintained) to the remaining communities. The number and positioning of these switches as shown is diagrammatic and will need to be confirmed upon final line route selection.

Line circuit breakers are included at the town sites to handle the charging current required for the approximate 120 km of distribution line that under normal conditions would be energized from one of the hydro plant. A motorized line disconnect switch suitable for line protection/guarantee purposes is also provided at each facility.

A fiber optic cable (installed on the power line structures) or a radio communications link is assumed to interconnect the hydro power plant and the diesel generator plant (if maintained) for the purposes of SCADA and any tele-protection requirements. It is anticipated that the hydro power plant will be operated remotely and the SCADA system will be monitored both at the existing diesel plant (or elsewhere in the community) and remotely at a Newfoundland Labrador Hydro control facility. Communication architecture and technical requirements will have to be finalized during future project phase.

Due to the distributed communities and hydro plants 5B and 8C-2 being some 35 km apart, a more sophisticated tele-protection system may be required. The details will be explored during detailed engineering.

It is anticipated that the hydro power plant will be operated remotely and the SCADA system will be monitored both at the existing diesel plants (and elsewhere in the respective communities) and remotely at a Newfoundland Labrador Hydro control facility. A multi-point communication architecture and system technical requirements will have to be finalized during future project phase.

The proposed design anticipates that the nominal operating voltage of the generators will be 4.16 kV; however, this can be tailored to a lower voltage during the detailed project design phase, based on equipment availability and economics. This voltage was selected to match the present community diesel generation system.

Each power plant will include 5 kV switchgear of the selected voltage class with necessary instrument transformers for metering and protection. All of the 5 kV hydro power plant switching equipment will be located in the power house.

The generator protection and control equipment will include modern solid state devices with required degree of redundancy with special emphasis on the islanded mode of operation.

The hydro power plant station services will normally be provided from the grid via a 4160/600V station service transformer and a motor control center to serve plant mechanical systems including the intake gate operation. The hydro power plant station services when a particular plant is not running will normally be back-fed from the other plant.

A 600/240/120V transformer will provide power house distribution. A 125VDC battery bank, changer and 120V UPS will to feed essential protection and control elements of the electrical system and communications system related to SCADA and voice systems.

Black start capability of the hydro power plant is considered essential based on the assumption that power from the existing communities' diesel generation (if maintained) will only serve as local emergency backup and will not be available to back-feed and start hydro

plants. Providing black start functionality will require sufficient capacity of the plant emergency diesel generator in order to provide power for turbine auxiliary systems necessary to start the units.

Options for synchronizing two running generation plants to each other will be reviewed and evaluated during detailed engineering. Paralleling and synchronizing of the hydro generators to the back-fed power from existing diesel plants is not anticipated.

With the remote nature of the hydro plant and the susceptibility to harsh winter weather conditions, along with necessity to enable plant black start, a local emergency diesel generator is provided to start essential turbine services, safeguard the plant auxiliary systems in the event of a protracted line outage, providing heat, lights and maintaining essential services.

5. Generation and Demand Capacity

The storage schemes under the two generation options were analyzed with the water balance model and historical flow data to quantify reservoir yields in terms of power that can be delivered. The 1986/1987 period was selected as the critical water year as it experienced the lowest amount of total annual inflows at each site. On an annual basis it has a 3% chance of recurrence for a flow record length of 33 years.

Power generation was calculated using power flows computed in the reservoir simulation and the mean monthly reservoir levels during each time step period. Net heads were calculated from the power flow using the relationship between power flow and the respective hydraulic loss coefficient ($\sum h_L = K \times Q_p$). K is the hydraulic loss coefficient for the configuration of the scheme water conductors. Power was computed being delivered at a constant value for every hour of the month.

Load data from NL Hydro for the isolated load centres of CHT, PHS, MSH and STL was analyzed and used as a basis for developing the annual load curves in Figure 3-1, Section 3.3. The 2037 forecasted peak loads were applied to the load patterns to derive the curves in Figure 3-1. The aggregated peak loads using the 2037 load values for PHS/MSH/STL amounted to 2605 kW. Required firm power from the storage hydro sites intended to serve these communities was therefore fixed at 2800 kW. However, since the communities of PHS/MSH/STL will have a mini-interconnected system in generation Option #2 then the extension of peak 2037 loads should take into account load diversity found in the NL Hydro data (i.e., the months in which peak load demand load occurs). The peak load for PHS/MSH/STL is lower at 2605 kW when this diversity occurs. In the case of where the mini-grid will cover CHT/PHS/MSH/STL the corresponding peak load with load diversity was 4245 kW, as shown in Figure 3-1.

This peak load curve for the four communities was used in comparing the monthly demand loads with generation under generation Option #2.

5.1 Generation Option #1

Generation Option #1 consists of two isolated grids supplying power to two sources of demand. That is, it was assumed that there will be no transmission interconnection between sites or communities. In Option #1, Site 5B (5B-1) will supply power to CHT which has a peak demand load of 1848 kW. The communities of PHS/MHS/STL, with a peak load of 2605 kW, will be serviced by Site 8D or ALX-B depending on the attributes of either storage site.

Two different demand load curves for the communities were applied in this comparison. Details of the applied load curves are provided in Section 3.3.1. It was assumed that the load patterns derived from historical data will be approximately applicable to power demand use in 2037.

5.1.1 *Site 5B*

For Option #1, Site 5B-1 provides 1850 kW of firm power based on the projected peak load for Charlottetown in 2037. Figure 5-1 indicates the storage scheme at Site 5B-1 satisfies demand for each month of the critical study period. It should be noted that the reservoir simulations targeted its yield to deliver the forecasted load during each month of the year. The simulations did not attempt to deliver flows that followed those required by the forecast load pattern.

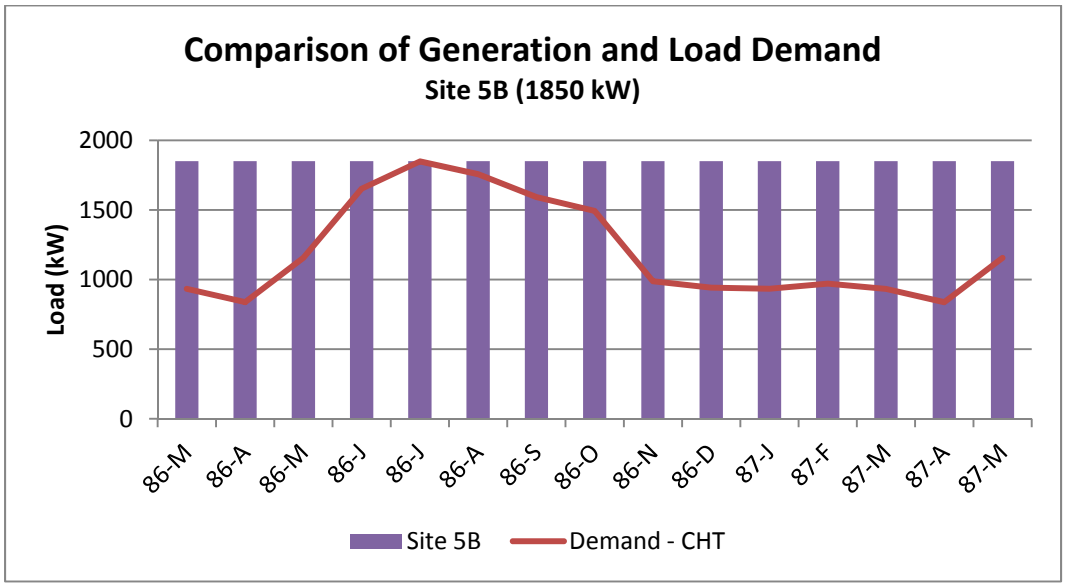


Figure 5-1: CHT Demand and Site 5B Generation in (1986/1987) Dry Year

5.1.2 *Site 8D*

For Generation Option #1 Site 8D provides 2800kW of firm power based on the projected load of PHS/MHS/STL in 2037. As displayed in Figure 5-2 the load demand is satisfied each month during the dry year of the study period.

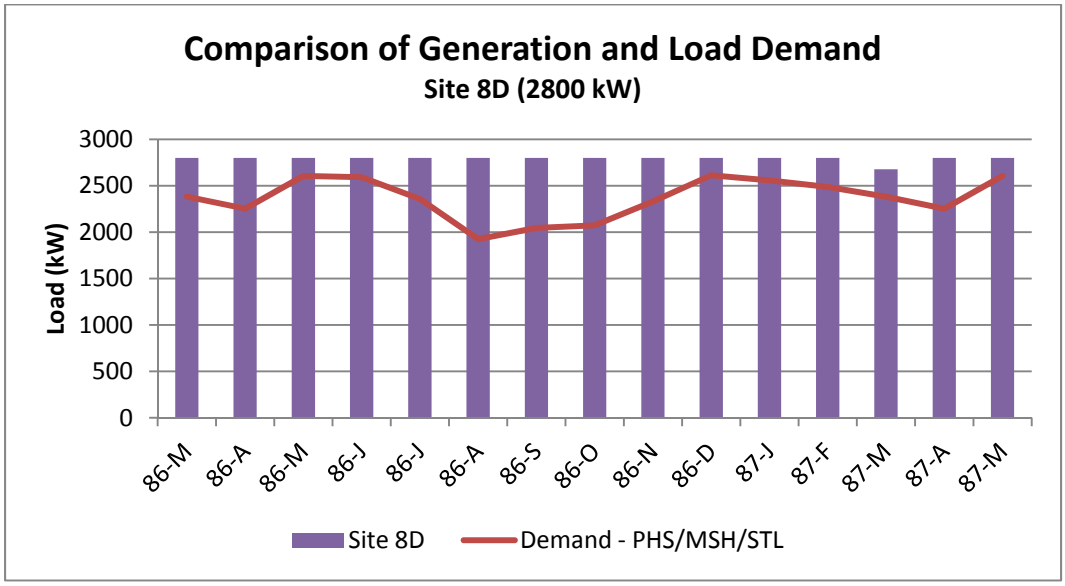


Figure 5-2: PHS/MSH/STL Demand and Site 8D Generation in (1986/1987) Dry Year

5.1.3 Site ALX-B

Site ALX-B is considered as an alternative hydro power site to storage Site 8D to satisfy the demand load of PHS/MHS/STL. As displayed in Figure 5-3 the load demand of the three communities can also be satisfied each month by the proposed ALX-B scheme during the dry study period.

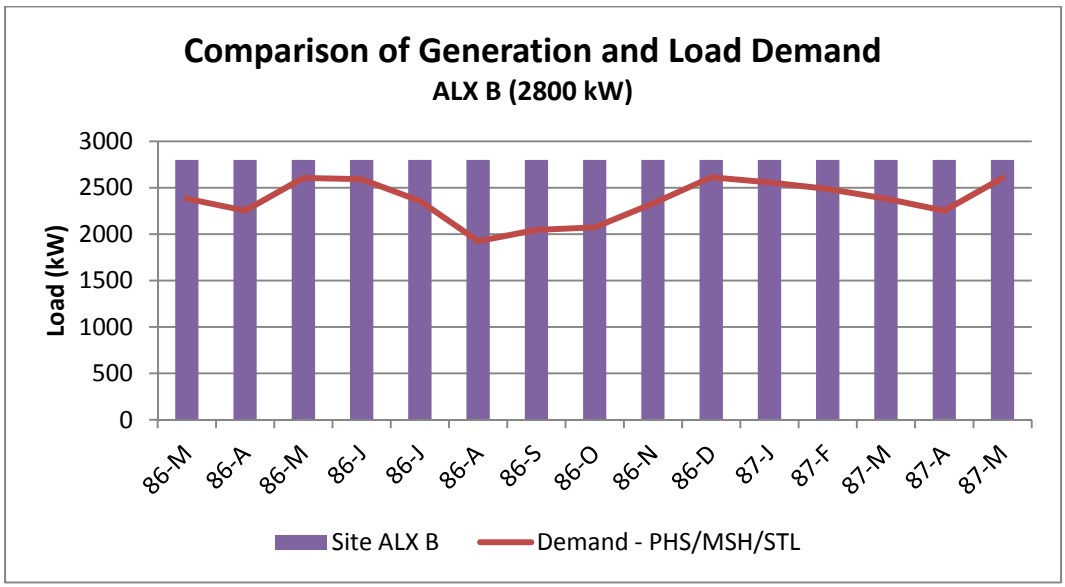


Figure 5-3: PHS/MSH/STL Demand and Site ALX-B Generation in (1986/1987) Dry Year

5.2 Generation Option #2

Generation Option #2 consists of two sites supplying power to the communities of CHT/PHS/MSH/STL with an interconnected transmission mini-grid between the proposed generation stations and communities. Because the aggregated demand curve of the four communities demonstrates a summer peaking load pattern, then a storage hydro site in conjunction with a run-of-river hydro site would be a suitable combination particularly because of the lower cost of the run-of-river hydro development. The storage site of Site 5B (5B-2) would provide a base load of 2300 kW for each month of the year. Summer peak loads can be satisfied from run-of-river scheme generation on the St. Lewis River during periods of high flow.

5.2.1 Site 5B-2 and Site 8C-2

In the case of run-of-river generation from Site 8C-2 there is a large variability in power generation from month to month and this is to be expected since there is no regulation of inflows. The headpond of 8C-2 has an almost negligible live storage. High flows during the spring and summer result in peak load generation which coincided with peak power demand of the annual load curve. Generation is reduced in the winter during periods of low flow.

The combination of Site 5B-2 and Site 8C-2 during the dry period experiences a small deficit in supply power during the winter months of December to March. During the dry year of 1986/87 the largest deficit occurred in February and is 362 kW. This is considered a deficit if the load curve for February is a straight horizontal line. The historical load pattern shows that on a daily basis load varies almost linearly from a peak demand of 3457 kW to 2074 kW. If actual generation from the proposed two generating stations is 3095 kW (3457–362) then this supplies a firm load over every day of February which occurs at 74% of the peak load on the load curve. Since the load factor (LF) of the demand load is approximately 80%, the average energy required for the month of February is 1858.5 MWh while the actual energy supplied is 2079 MWh. This exceeds the demand energy and only requires that the peak energy use be shifted to the non-peak periods. In this way, there would be no deficit in the demand.

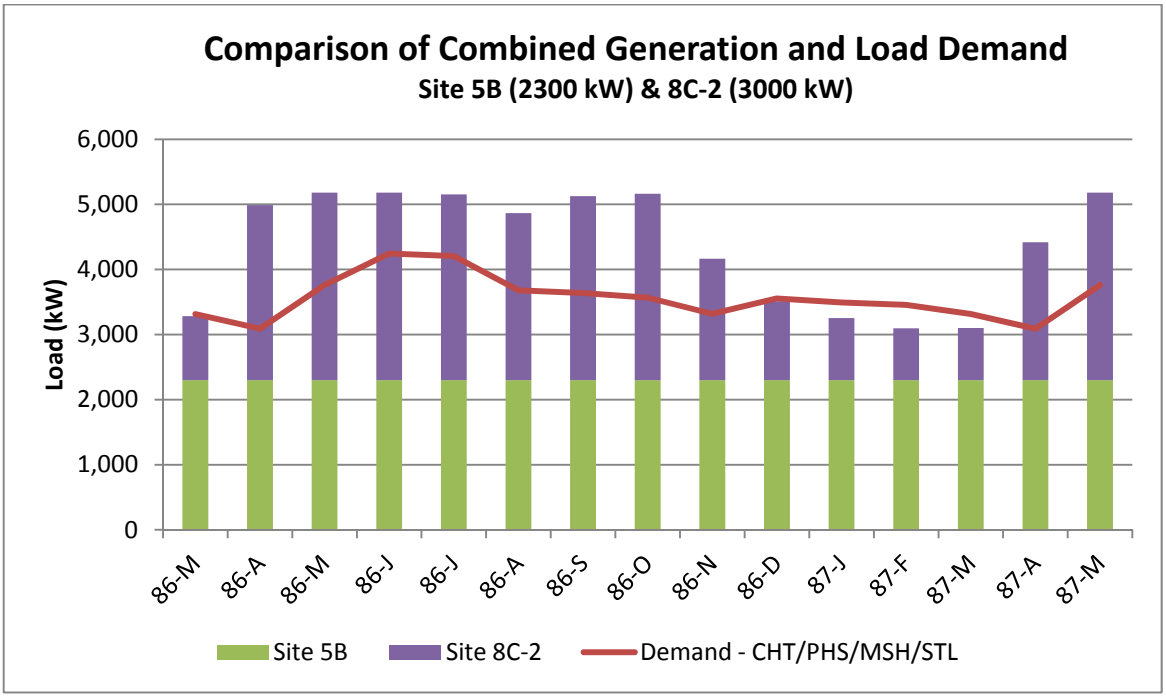


Figure 5-4: CHT/PHS/MSH/STL Demand and Site 5B and Site 8C-2 Generation in (1986/1987) Dry Year

6. Cost Estimates and Schedule

6.1 Cost Estimates - General

As part of the study of potential storage projects for southern communities, cost estimates were prepared for: the preferred storage option of Site 5B-2 (storage hydro development with an installed capacity of 2.5 MW); run-of-river Site 8C-2 with installed capacity of 3.0 MW; Site 8D; and, Site ALX-B.

These estimates were prepared to form the basis for budget authorization, appropriation, and/or funding, based on preliminary drawings, studies, limited site investigation, mapping and equipment optimization.

The cost estimates are classified as Association for the Advancement of Cost Engineering (AACE) Class 3 level estimates.

The target accuracy range of these estimates is -5% to -20% on the low side, and +10% to +30% on the high side.

The level of contingency overall is 15 to 20%.

6.2 Basis of Estimates

The cost estimates were compiled based on the following parameters:

- Estimated costs for water-to-wire (W2W) generating equipment (turbines, governor, HPU units, generator with excitation) are based on the budgetary quotes obtained in September and October 2012, and in January 2013.
- Auxiliary electrical equipment and systems costs included in manufacturers' quotations (control, protection, metering, MV switchgear, and Station AC and DC services).
- Assessing Hatch's database for ancillary/balance of plant (BOP) mechanical equipment pricing for recent similar projects
- Installation and commissioning cost for major mechanical/electrical equipment as well as for BOP equipment was based on Hatch database benchmarks from similar hydroelectric projects.
- Assessing the site labour productivity adjustment factor to allow for local Northern impacts that will drive the field labour resource requirement on the site. The adjustment factor used to account for impact at this estimate stage is for climatic impacts, site access, site and working conditions.
- All costs are in October 2012 Canadian Dollars.

6.3 Estimate Methodology/Approach

The estimates for the storage schemes were prepared using detailed estimating methods ("first principle") based on preliminary engineering drawings as described in Section 8 of the Phase 2 Final Report. All costs were developed for the direct cost portion of the estimate with the indirect costs being a percentage of the estimated direct cost portion of the estimates based on Hatch benchmark data. The following aspects were considered:

- For each type of civil works, or for each unit price item, the construction labour crew, the construction equipment fleet and the construction materials were selected to achieve suitable productivity and to complete the task within the construction schedule. Unit prices include Contractors' overhead and profit.
- Localised productivity adjustment.
- The supply cost for major and minor permanent equipment.
- The delivery cost to the site.
- Allowances for construction camps/subsistence.
- Appropriate contingencies.
- Hydro-mechanical equipment (the mass of gates, stop-logs, guides and hoisting equipment is estimated in kilograms, using Hatch benchmarks of specific weight of each of the these elements).

6.4 Elements Included in the Cost Estimates

It was assumed the projects will be structured under an Engineering, Procurement and Construction Management (EPCM) project delivery method format and would be constructed using local contractors and local labour to the fullest extent possible.

The project cost estimates have been structured using the following estimate categories, as described in Section 8 of the main report.

- A - Civil Works (Access Roads & Reservoir Clearing, Cofferdams & Dewatering, Embankment Dam, Diversion & Fish Ladder, Spillway, Intake and Power Conveyance, and Powerhouse)
- B - Mechanical and Electrical Works (Gates & Hoists, Powerhouse M&E, Substation & Transmission Lines)
- C - Construction Facilities, Indirect Costs and Northern Factor (30% of A+B)
- Contingencies:
  - Civil Works 20%
  - Mechanical & Electrical Works 10%

- Environmental, engineering, administration and construction management by the Owner's Engineering firm.

6.4.1 *Contingencies*

Contingencies are included in the estimates to provide for costs which cannot be specifically identified at the time of estimate preparation, but which can be foreseen with varying degrees of probability throughout the life of the project.

The contingencies carried are an assessment of risk exposure that the contractors face due to weather restraints, labour and materials availability and productivity and for the degree of estimate accuracy.

6.4.2 *Construction Facilities, Indirect Costs and Northern Factor*

Applied in the estimates is 30% of the total civil & electrical/mechanical direct cost to cover the following contractors' expenses:

- site supervision, survey and quality control expenses
- site and home office expenses and travel
- mobilization and demobilization
- temporary construction camp (supply, installation & operating expenses) or subsistence costs
- site facilities expenses (power, water and sanitary; site trailers; local transport; small tools; security and safety; storage; hoisting and handling of permanent equipment and materials; weather protection and site environmental protection)
- lay-down areas and temporary construction roads
- contractor's bonding and insurance
- the Northern Factor - constructability and scheduling constraints assumed with project execution in a harsh northern climate.

6.4.3 *Environmental, Engineering, Administration and Construction Management by the Owner's Engineer*

These costs have been included at 7.5 percentage of the total estimated construction cost.

6.5 Exclusions

Estimated costs are exclusive of: escalation beyond October 2012 price levels, HST, land acquisition, isolated grid and interconnection costs, financing/IDC, and Owner's costs.

6.6 Summary of Estimated Costs

Two summary tables are provided: Table 6-1: Potential Storage Sites ALX-B and 8D; Table 6-2: Site 5B-2 + 8C-2. The detailed cost estimates are provided as Figures 6-1, 6-2, 6-3 and 6-4 in Attachment 3.

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Table 6-1: Summary of Estimated Costs - Alternative Potential Storage Projects for PHS, MSH and STL

No	Item Description	Site ALX-B	Site 8D
	Installed Capacity (kW)	3,500	3,500
	Net Head (m)	35.1	32.5
A - Civil Works			
1	Access Roads & Reservoir Clearing	$5,490,000	$3,815,000
2	Cofferdams & Dewatering	$935,000	$396,500
3	Dam & River Diversion	$18,474,500	$54,388,000
4	Spillway (Overflow)	$11,904,400	$20,350,000
5	Intake and Power Conveyance	$7,564,200	$3,011,200
6	Powerhouse & Substation	$1,382,600	$2,017,000
	Sub-Total - Civil Works	**$45,750,700**	**$83,977,700**
B - Mechanical and Electrical Works			
1	Gates & Hoists	$807,900	$673,000
2	Powerhouse M & E	$5,111,000	$5,054,000
3	Substation & Transmission Lines	$8,840,000	$2,875,000
	Sub-Total - Mechanical & Electrical Works	**$14,758,900**	**$8,602,000**
	Subtotal A - Civil Works	$45,750,700	$83,977,700
	Subtotal B - Mechanical & Electrical Works	$14,758,900	$8,602,000
	Subtotal C - Construction Facilities, Indirect Cost & Northern Factor	$18,152,900	$27,773,900
Subtotal Without Contingencies		**$78,662,500**	**$120,353,600**
Contingencies		**$10,626,000**	**$17,655,740**
Total Est	**Concrete Works**	**$89,288,500**	**$138,009,340**
Environmental, Engineering, Administration and Site Inspection		**$6,696,600**	**$10,350,700**
Total Estimated Project Cost		**$95,985,100**	**$148,360,040**
	Total Costs in $/kW	***$27,400***	***$42,400***

Exclusions:
- escalation beyond October 2012
- taxes
- land
- isolated grid and interconnection costs
- financing
- Owner's costs

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Table 6-2: Summary of Estimated Costs - Preferred Storage Project (5B + 8C-2)

No	Item Description	Site 5B	Site 8C-2	TOTAL
	Installed Capacity (kW)	2,500	3,000	5,500
	Net Head (m)	31.4	17.5	
A - Civil Works				
1	Access Roads & Reservoir Clearing	$5,940,000	$2,250,000	$8,190,000
2	Cofferdams & Dewatering	$396,500	$930,000	$1,326,500
3	Dam & River Diversion	$6,653,000	$8,527,500	$15,180,500
4	Spillway (Overflow)	$1,704,000	$3,655,000	$5,359,000
5	Intake and Power Conveyance	$4,741,000	$1,072,500	$5,813,500
6	Powerhouse & Substation	$1,334,000	$2,445,000	$3,779,000
	Sub-Total - Civil Works	**$20,768,500**	**$18,880,000**	**$39,648,500**
B - Mechanical and Electrical Works				
1	Gates & Hoists	$672,000	$900,300	$1,572,300
2	Powerhouse M & E	$4,808,600	$4,782,400	$9,591,000
3	Substation & Transmission Lines	$2,600,000	$2,950,000	$5,550,000
	Sub-Total - Mechanical & Electrical Works	**$8,080,600**	**$8,632,700**	**$16,713,300**
	Subtotal A - Civil Works	$20,768,500	$18,880,000	$39,648,500
	Subtotal B - Mechanical & Electrical Works	$8,080,600	$8,632,700	$16,713,300
	Subtotal C - Construction Facilities, Indirect Cost & Northern Factor	$8,654,700	$8,253,800	$16,908,500
Subtotal Without Contingencies		**$37,503,800**	**$35,766,500**	**$73,270,300**
Contingencies		**$4,961,800**	**$4,639,300**	**$9,601,100**
Total Est	**Concrete Works**	**$42,465,600**	**$40,405,800**	**$82,871,400**
Environmental, Engineering, Administration and Site Inspection		**$3,184,900**	**$3,030,400**	**$6,215,300**
Total Estimated Project Cost		**$45,650,500**	**$43,436,200**	**$89,086,700**
	Total Costs in $/kW	***$18,300***	***$14,500***	***$16,200***

Exclusions:

- escalation beyond October 2012
- taxes
- land
- isolated grid and interconnection costs
- financing
- Owner's costs

It was concluded from the estimated costs for Site ALX-B and Site 8D that neither potential storage site is economically attractive. However, estimated costs for Site 5B (5B-1 and 5B-2) and Site 8C-2 are very competitive.

6.7 Cash Flows

Annual and cumulative cash flows for Site ALX-B, Site 8D, and Site 5B-2 plus Site 8C-2 were prepared and used for the preliminary economic analysis.

6.8 Operation and Maintenance Costs (O&M) Costs

In addition to the project construction cost, the costs required to cover future operating and maintenance were also considered. These costs can vary greatly from one station to another.

6.8.1 Benchmarking

Based on industry data, the annual operation and maintenance costs for any given unit or plant may vary significantly depending on factors such as the original design and construction of the facilities, the number of units, the age, size and type of the equipment, the historical use and maintenance levels since commissioning, allowances for access and staffing of remote facilities, and the operating constraints and patterns appropriate to each site. Variations in individual plant costs-per-MW of 75% or more are seen in the industry data. Various cost estimation approaches have been published based on statistical data gathered from hydro facilities across North America. Three approaches have been used to better assess the Operation and Maintenance (O&M) costs, as described below.

6.8.1.1 Method 1

Schetter, J. R. "Using Benchmarking to Assess, Improve Hydro Plant Performance", Hydro Review, October 2002.

Schetter developed equations based on the annual energy production and the plant capacity factor for data normalization using relatively recent data that includes current methods for performing maintenance of hydro facilities and accounts for plant size, providing average expenditure levels for small and medium sized facilities as indicated below.

- Benchmark Reference for Small Plants <10 MW

2003 US $ $11.04 per MWh @ 51.4% capacity factor

- Benchmark Reference for Medium Plants >10 MW

2003 US $ $2.86 per MWh @ 48.7% capacity factor

Operation costs include:

- Supervision and Engineering
- Costs for water used for power
- Hydraulic expenses

- Electric expenses
- Rents

Production Maintenance costs include:

- Supervision and Engineering
- Structures
- Reservoirs, Dams and Waterways
- Electric Plant
- Miscellaneous Hydraulic Expenses

6.8.1.2 *Method 2*

Idaho National Engineering and Environmental Laboratory (INEEL), "Estimation of Economic Parameters of U.S. Hydropower Resources", June 2003.

INEEL has also recently developed various cost estimation equations based on a database of some 2,155 U.S. hydropower sites. Both fixed and variable O&M costs were found to correlate well with plant capacity. The cost estimating equations for fixed and variable operation and maintenance are as follows.

Cost (2002 US$) = A x [Capacity (MW)]^B

Estimating Tool	Coefficient (A)	Coefficient (B)
Fixed Operation and Maintenance	2.4×10^4	0.75
Variable Operation and Maintenance	2.4×10^4	0.80

Fixed costs include:

- Operation supervision and engineering
- Maintenance supervision and engineering
- Maintenance of structures
- Maintenance of reservoirs, dams, and waterways
- Maintenance of electric plant
- Maintenance of miscellaneous hydraulic plant.

Variable costs include:

- Water for power
- Hydraulic expenses
- Electric expenses
- Miscellaneous hydraulic power expenses

- Rents.

6.8.1.3 *Method 3 The Gordon Formula*

The following formula was developed based on recent O&M data:

Cost (2005$) = 60,000 x [Capacity (MW)]^0.65 + 45 x [Capacity(MW)] x N x C

Where:

Capacity (MW) = Total Installed Capacity

N = Number of units

C = man-hour cost for operating staff (estimated at $75/hr)

6.8.2 *Summary of Estimated O&M Costs*

For Site 5B-2 and 8C-2, based on the available information and anticipated average energy production, the following costs were established.

System	Generating Station	Installed Capacity (MW)	Benchmarked Annual Values (2012) $							Annual Average including Water & Tax
			Schetter	INEEL			Gordon Formula	Hatch Estimate	Average	
				Fixed	Variable	Total				
Coastal Labrador Hydro, Southern Communities	Site 8C-2 (run-of-river)	3.0	$203,000	$74,000	$78,000	$152,000	$186,000	$181,000	$181,000	**$240,000**
	Site 5B-2 (storage)	2.5	$169,000	$65,000	$68,000	$133,000	$168,000	$180,000	$163,000	**$220,000**
	Totals	**5.5**	**$372,000**	**$139,000**	**$146,000**	**$285,000**	**$354,000**	**$361,000**	**$344,000**	**$460,000**

6.9 Project Schedule - Site 5B-2 and 8C-2

6.9.1 *Schedule Structure*

A project implementation schedule was developed using Microsoft Project Planner for the preferred storage project – Site 5B-2 plus 8C-2. The schedule is provided in Attachment 3, Figure 6-5.

The activities in the schedule are grouped into (3) main categories and subcategories based on the stages of project development:

- ENVIRONMENTAL PROCESS
- ENGINEERING, DESIGN AND PROCUREMENT
  - Completion of FEL-3- Project Definition Phase
  - FEL-4-Implementation Phase
- CONSTRUCTION AND INSTALLATION

- Civil Works
- W2W Equipment, Switchyard & Transmission.

6.9.2 *Contract and Construction Sequences*

- The time frame for the Environmental Process is estimated at approximately 2½ years including Permits and Approvals (Provincial and Federal), after site preliminary investigations and preliminary engineering.
- Completion of FEL-3 will be concurrent with the Environmental Process.
- Implementation Phase FEL-4 will start after completion of FEL-3 – Site Investigations and Detailed Engineering, and project sanctioning.
- A critical path date is the contract award for the W2W Equipment and is indicated in 2nd Quarter of Year 3. Contract award for General Civil Works Contract is indicated in the 4th Quarter of Year 3, and, award of BOP M&E contract in Quarter 1 of Year 4.
- Start of construction is assumed to start as soon as the general civil works contract is awarded, with the following activities:
  - Mobilization of contractor equipment and labour, construction of access roads and cofferdam construction will take place in parallel for Site 5B-2 and Site 8C-2.
  - After completion of the above mentioned activities and river diversions are in use, the dam construction, spillway and powerhouse construction will proceed for both sites.
  - Start of reservoir impounding after completion of clearing and completion of dam.
  - W2W Equipment installation including commissioning will start after powerhouse crane Installation and building enclosure.

6.9.3 *Key Dates and Milestones*

Key dates and milestones are:

- NLH Approval to Proceed on FEL-4 Phase — Qtr. 2 (Year 2)
- Notice of Completion Published — Qtr. 4 (Year 2)
- Contract Award (W2W) — Qtr. 2 (Year 3)
- Contract Award (General Contract) — Qtr. 3 (Year 3)
- Commence Construction (5B-2) — Qtr. 1 (Year 4)
- River Diversion in Use (5B-2) — Qtr. 3 (Year 4)
- Start Reservoir Impounding (5B-2) — Qtr. 3 (Year 5)
- Powerhouse Enclosed (5B-2) — Qtr. 3 (Year 5)
- In-Service (5B-2) — Qtr.2 (Year 6)

- Commence Construction (8C-2) Qtr. 1 (Year 4)
- River Diversion in Use (8C-2) Qtr. 3. (Year 4)
- Start Reservoir Impounding (8C-2) Qtr. 4. (Year 5)
- Powerhouse Enclosed (8C-2) Qtr. 4 (Year 5)
- In-Service (8C-2) Qtr. 3 (Year 6)

6.9.4 Critical Path

The following activities are expected to be critical for the project implementation of Site 5B-2 plus Site 8C-2.

- Site Investigations and Detailed Engineering/Final Design
- NLH Review and Approval to Proceed
- Tender Documents & Drawings
- Bid Period (W2W Equipment) & Contract Award
- Bid Period (General Contract) & Contract Award
- Mobilization & Site Facilities (Site 5B-2)
- Mobilization & Site Facilities (Site 8C-2)
- Powerhouse & Substation Civil Works (both sites)
- PH Crane Installation (both sites)
- Manufacture and Delivery of W2W Equipment (both sites)
- W2W Equipment Erection (both sites)
- W2W Testing & Commissioning (both sites).

7. Economic Analysis

An economic analysis of the generation scenarios under Option #1 and Option #2 was undertaken by calculating the levelized cost of energy for both the demand and supply cases. In the case of an isolated transmission grid as proposed for the four southern communities, useful energy is limited to what the communities will consume. Any excess power and energy generated by the sites would not be utilized and there would be no other known locations to transmit this energy. Nevertheless, load forecasts are not always precise and actual demand in 2037 may exceed the forecast thus providing additional consumers.

The main inputs and assumptions in the economic analysis are the discount rate and the amortization period. The discount rate adopted was 7% based on NLH's estimate of the current opportunity cost of capital for energy investments. The selected amortization period/repayment period for the investments is 50 years, as the economic life of hydroelectric generation facilities can be well over this period. Interest on borrowing for the cost of construction (Interest During Construction [IDC]) over the construction period is assumed to be capitalized over this period until the hydro plants commence operations. IDC was calculated by capitalizing the cash flow in the respective years at 7%. Levelized costs were calculated by applying a capital recovery factor (50 years; 7%) to the total cost (construction cost plus IDC).

Operation and maintenance costs were included as a recurrent cost occurring over the plants' operational period and was added to the levelized capital cost to give a uniform annual cost stream. The levelized cost of energy for both demand and supply scenarios were calculated from the derived annual uniform cost amounts and energy for each generation option. The results of the levelized cost of energy from the plants are summarized in Table 7-1.

Table 7-1: Summary of Results – Storage Hydro Projects
Development Costs and Levelized Cost of Energy for Generation Scenarios

Site Number	Communities Served	Generation Scenario	Type of Hydro Development	Forecast Community Peak Load (2037)	Installed Capacity	Plant Firm Capacity @ 97%	Annual Firm Energy Supplied at 97%	Average Annual Demanded Energy	Capacity Factor	Cost d/	Cost/kW	O & M Cost	Cost + IDC	Levelized Ann. Cost (50 yr, 7%)	2012 Cost of Demand Energy c/	2012 Cost of Supplied Energy c/
				(kW)	(kW)	(%)	(MWh)	(MWh)	(%)	($ Millions)	($/kW	($ Millions/year)	($ Millions)	($ Millions)	($/kWh)	($/kWh)
5B-1 a/	Charlottetown	Option # 1	Storage	1848	2,100	1,850	16,206	11,045	60.0	43.7	20,800	0.33	48.10	3.82	0.345	0.235
8D	PHS/MSH/STL	Option # 1	Storage	2605	3,500	2,800	24,528	20,597	67.2	148.4	42,400	0.33	162.31	12.09	0.587	0.493
ALX-B	PHS/MSH/STL	Option # 1	Storage	2605	3,500	2,800	24,528	20,597	67.2	96.0	27,400	0.33	107.81	8.14	0.395	0.332
5B-1 + 8D	CHT & PHS/MSH/STL	Option # 1	Storage	4245	5,600	4,650	40,734	31,642	64.5	192.1 e/	34,300	0.46	201.67	15.07	0.476	0.370
5B-1 + ALX-B	CHT & PHS/MSH/STL	Option # 1	Storage	4245	5,600	4,650	40,734	31,642	64.5	139.7 e/	24,900	0.46	146.92	11.11	0.351	0.273
8C-2	PHS/MSH/STL	Option # 2	RoR	na	3,000	Variable	na	na	na	43.4	14,500	na	na	na	na	na
5B-2 b/	CHT & Part PHS/MSH/STL	Option # 2	Storage	1848	2,500	2,300	20,148	20,148	92.0	45.7	18,300	0.33	50.19	3.97	0.197	0.197
5B-2 + 8C-2	CHT & PHS/MSH/STL	Option # 2	Storage+RoR	4245	5,500	3,095	38,173	31,641	65.7	89.0 e/	16,200	0.46	98.49	7.60	0.240	0.199

Notes:
a/ Site 5B-1 delivers 1850 kW of firm energy to Charlottetown
b/ Site 5B-2 would deliver 2300 kW of firm power with the excess energy over the demand at CHT exported to PHS/MSH/STL
c/ Economic analysis period is 50 years; discount rate = 7%
d/ In 2012 Cdn Dollars; Owner's cost, financing/IDC, taxes and southern Labrador interconnection costs are excluded
e/ Estimated direct cost for interconnection between CHT/PHS/MSH/STL is $14 million

8. Conclusions and Next Steps

8.1 Conclusions

On the basis of the new mapping and the analysis completed, it has been concluded that three hydroelectric storage developments at Site 5B, Site 8D and Site ALX-B are technically viable and are able to produce firm power for the communities of Charlottetown, Port Hope Simpson, Mary's Harbour and the town of St. Lewis.

Two base generation options for providing firm power to the communities were examined that assessed the ability of the sites to deliver firm power based on a projected load demand and considered the cost factor of producing this power. Reservoir yields were verified thereby providing an estimate of the reliability of firm power. Layouts of the proposed storage sites were completed, available reservoir capacities were estimated from the new mapping and cost estimates for construction of the schemes were prepared. Based on the work undertaken, the conclusions arrived at on the potential for hydro storage sites to displace diesel generation at the four communities are as follows:

1. **Generation Option #1**

   a. Under Generation Option #1 it is technically viable to have a hydro storage site (Site 5B-1) on the Gilbert River that would supply firm power of 1,850 kW to the Charlottetown community. Site 5B-1 would be able to totally displace diesel generation in Charlottetown.

   b. Site 5B-1 is the only natural storage site of the three potential storage sites analyzed. Its reservoir size would be approximately 104 MCM live storage with a surface area of 24 km^2 if only Charlottetown is being supplied with power.

   c. Neither Site 8D nor Site ALX-B are natural storage sites but conservation reservoirs can be created by constructing high dams.

   d. Preliminary designs of storage schemes indicated that firm power of 2,800 kW can be delivered from either Site 8D or Site ALX-B for the communities of Port Hope Simpson, Mary's Harbour and St. Lewis. Therefore, when combined with Site 5B the total firm power demand of 4,650 kW can be generated and supplied to all four communities.

   e. The total cost of constructing Site 5B-1 (1,850 kW) and Site 8D (2,800 kW) is estimated at $192.1 million. The levelized cost of energy on the demand side is $0.476/kWh and reduces to $0.370/kWh on the supply side. This generation scenario is not economically attractive.

   f. The combined generation from Site 5B-1 and Site ALX-B can also supply 4,650 kW of firm power as an alternative to the combination of Site 5B-1 and Site 8D. The cost would be approximately $139.7 million and the estimated levelized cost of demand energy is lower at $0.341/kWh. On the supply side, the levelized cost of energy is

$0.265/kWh. This generation scenario may be economically viable and should be further assessed.

2. Generation Option #2

a. Under Generation Option #2 the generation of firm power from Site 5B-2 is combined with the run-of-river hydro site 8C-2. The reservoir size at Site 5B-2 can be increased to 116 MCM and 2,300 kW of firm power can be delivered from this site to an inter-connected mini-transmission grid linking all four communities. Generation from Site 8C-2 is variable but when these were estimated for the critical dry period, the combined power and energy from Site 5B-2 and Site 8C-2 can satisfy the forecasted load demand, from all four communities.

b. The most economical generation option is to have storage at Site 5B-2 to deliver 2,300 kW of firm power along with variable power from Site 8C-2. The total cost would be approximately $89 million and the levelized cost of demand energy is the lowest of all scenarios analyzed at $0.240/kWh and $0.199/kWh on the supply energy side.

c. If run-of-river Site 8C-2 on the St. Lewis River cannot be developed, then the next most favorable generation scenario for firm power is Site 5B-1 at an installed capacity (IC) of 2,100 kW (firm capacity of 1,850 kW) and ALX-B with a firm capacity of 2,800 kW and an installed capacity of 3,500 kW. The potential generation scenario of Site 5B-2 and ALX (Phase 2 run-of-river) was also assessed; however, the firm power from this combination does not meet the forecasted demand for the four towns.

8.2 Next Steps

a. The hydrological database used in this study comprised synthesized flow series and these need to be further evaluated and verified during the next study stage. Since Site 5B has reasonable attributes for a hydro storage site, a stream flow recording station (intended for Site MK S-2) should be established on the Gilbert River in the vicinity of the proposed powerhouse. Ice studies should be included as a part of any future hydrological measurements.

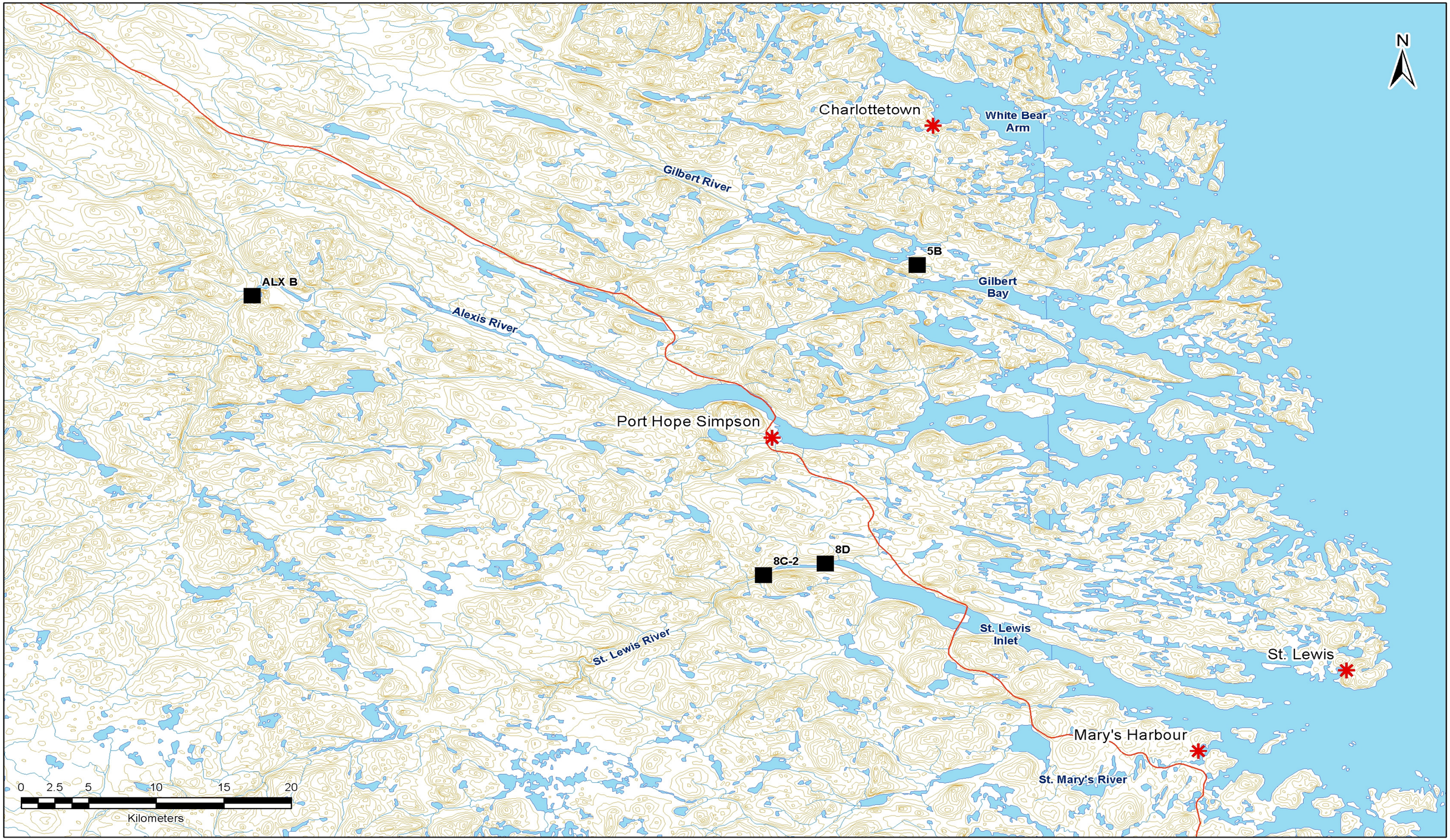
b. The evaluation of storage sites for delivering firm power was completed without additional environmental assessment beyond what was undertaken for previously studied run-of-river sites. Ecological flows or by-pass flows were not quantified or included in the water balances. These must be an integral part of any additional environmental assessments. Planning these activities will be part of the next stage when a decision on scheme development is made.

c. Dam safety studies must be included in the design stage of any storage site because their infrastructure designs impact on the hazard classification of the dams and the resulting inflow design flood.

Attachment 1

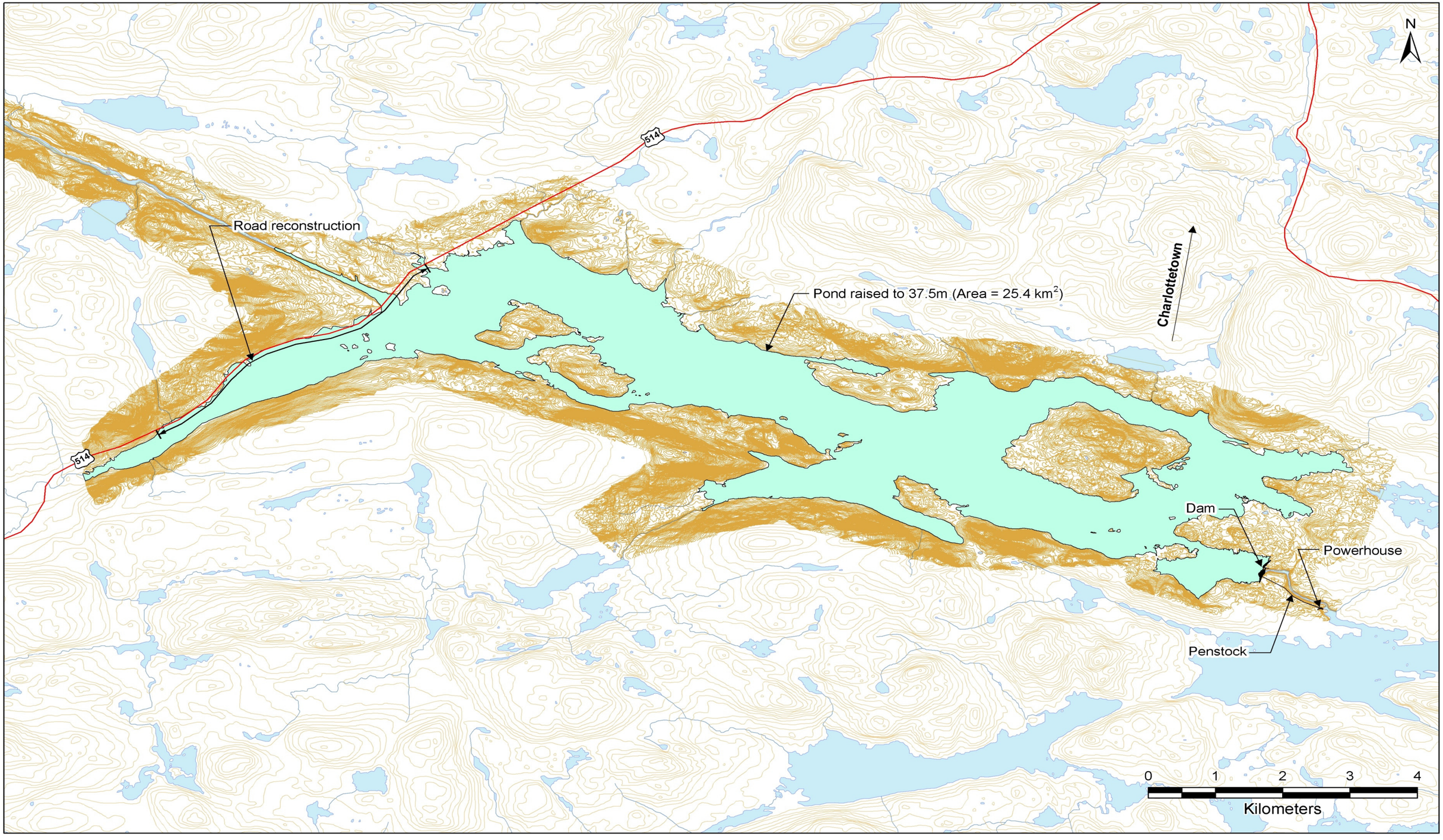
Site/Reservoir Maps

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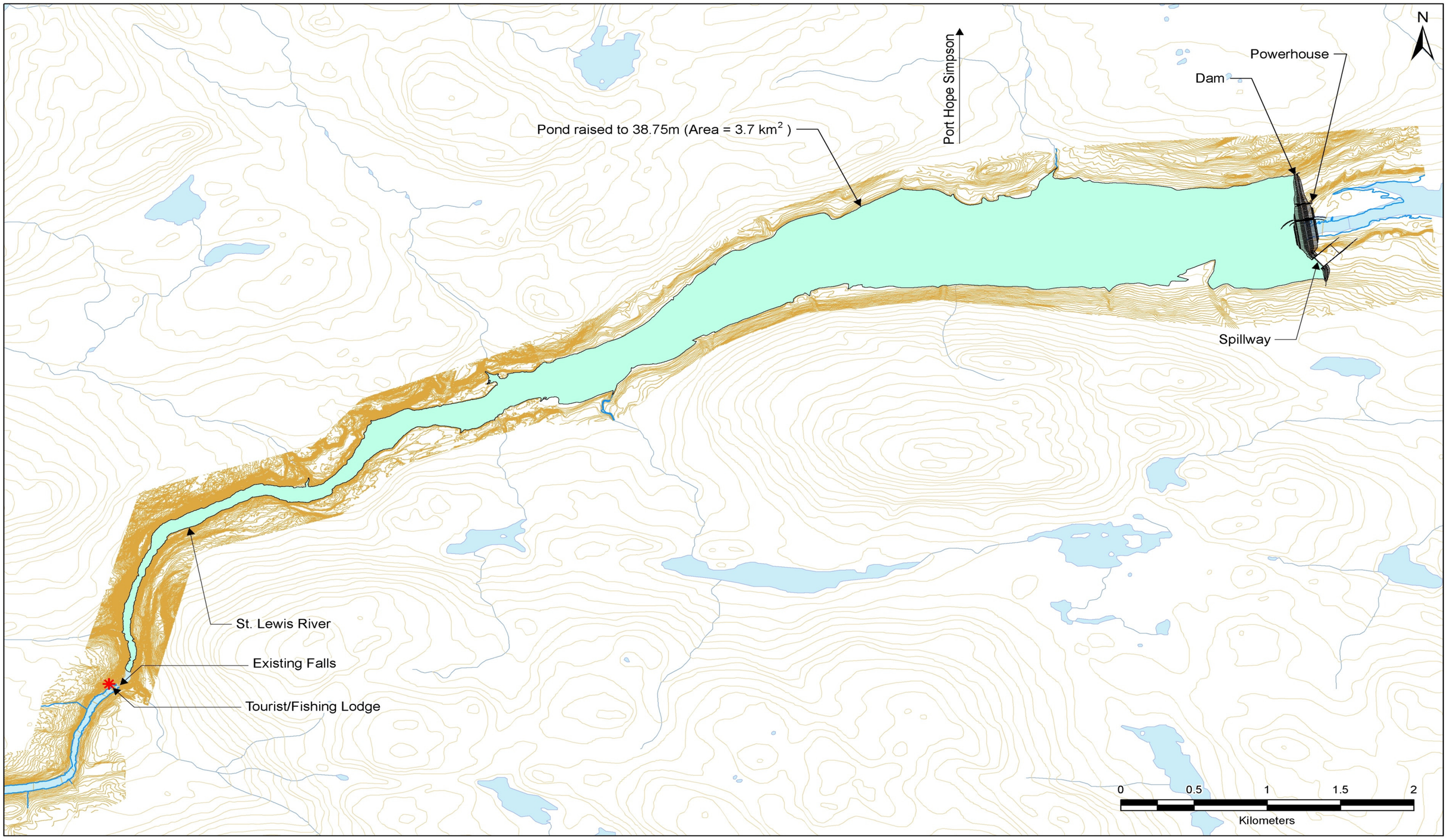
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Figure 1-1
Project Location Map
Coastal Labrador Hydro - Potential Storage
Newfoundland Labrador Hydro



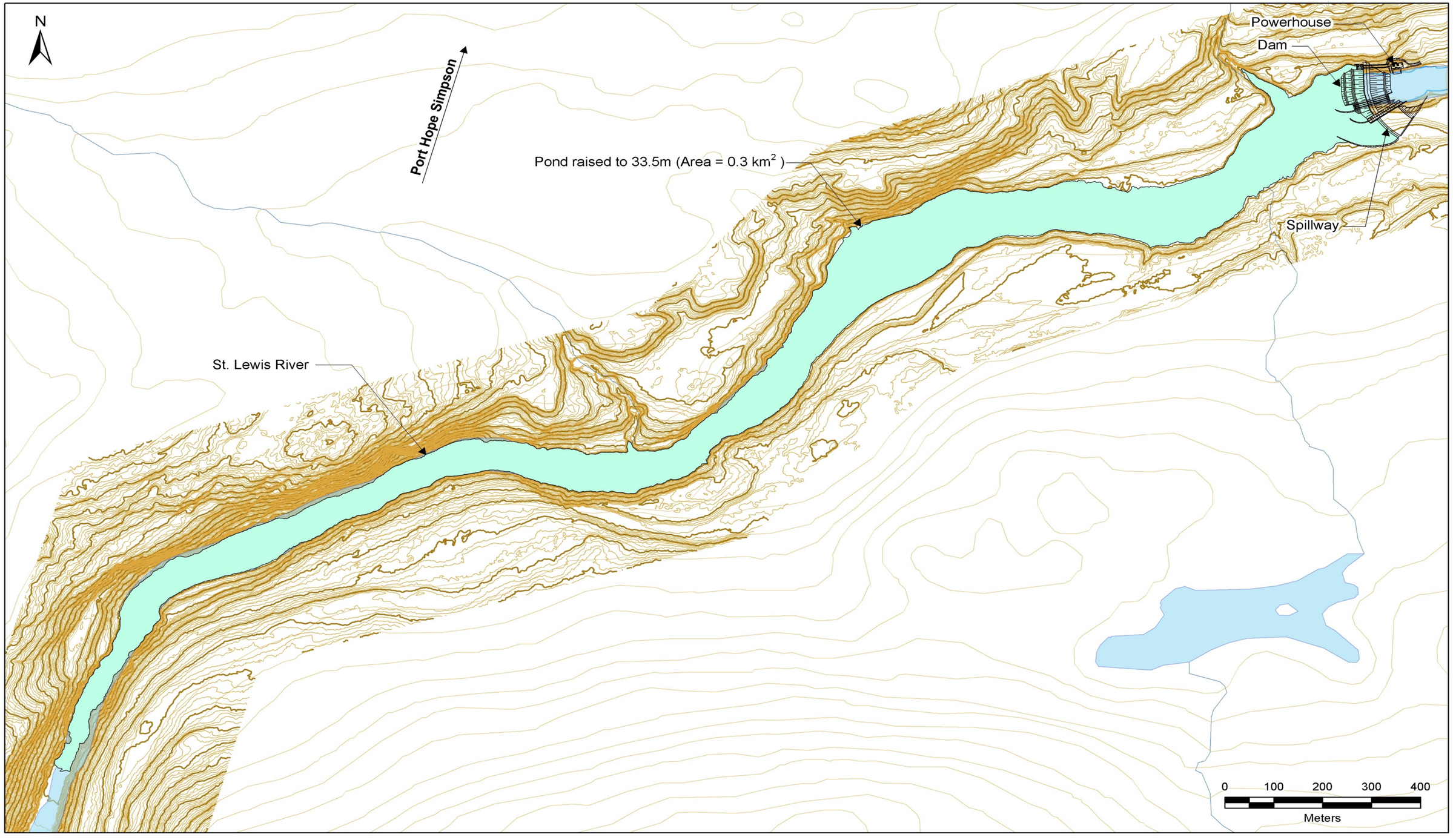
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Figure 1-2
Site 5B Headpond Inundation
Coastal Labrador Hydro - Potential Storage
Newfoundland Labrador Hydro



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Figure 1-3
Site 8D Headpond Inundation
Coastal Labrador Hydro - Potential Storage
Newfoundland Labrador Hydro



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Figure 1-4
Site 8C-2 Headpond Inundation
Coastal Labrador Hydro - Potential Storage
Newfoundland Labrador Hydro

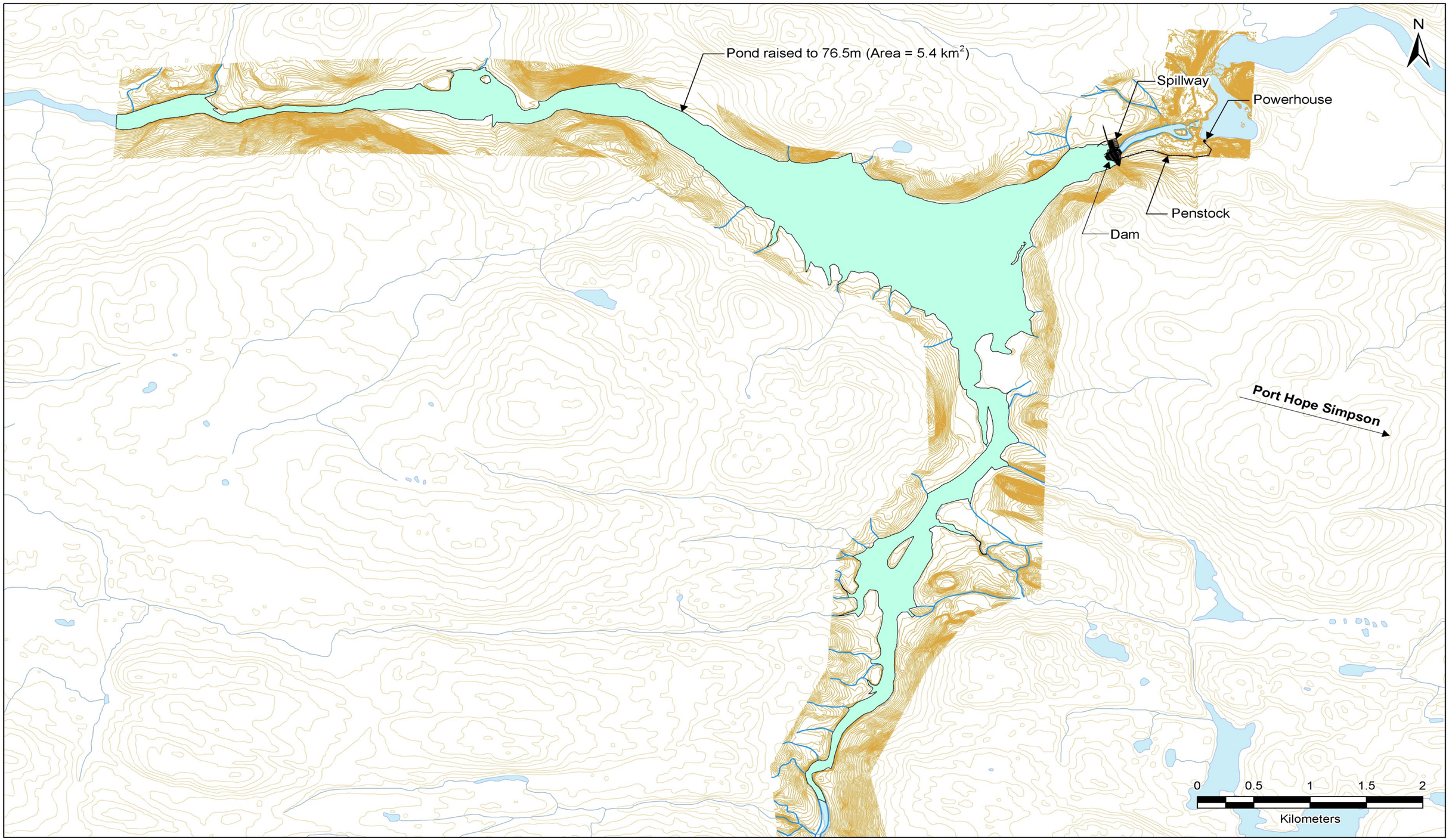


Figure 1-5
Site ALX B Headpond Inundation
Coastal Labrador Hydro - Potential Storage
Newfoundland Labrador Hydro

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Attachment 2

Drawings

Safety • Quality • Sustainability • Innovation



PLAN – GENERAL ARRANGEMENT SITE 5B

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SCALE: 1:2500

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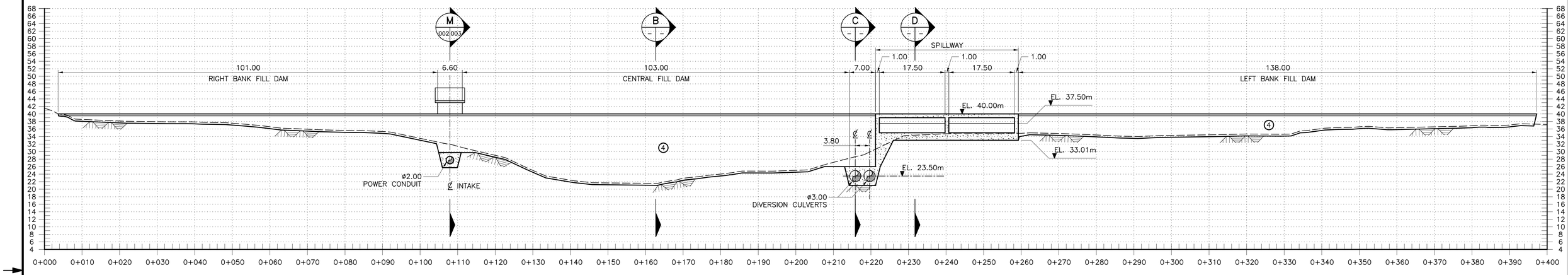
NL HYDRO
ST, JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: POTENTIAL STORAGE

SITE 5B –
GENERAL ARRANGEMENT PLAN

DESIGN PREPARED	G. FRANK
DESIGN CHECKED	M. McFARLANE
DRAWING PREPARED	S. RUSSELL
DRAWING CHECKED	J. WAYE
PROJECT MANAGER	M. McFARLANE
SCALE	1:2500 (D-SHEET)
HATCH Ltd. PROJECT NO.	H340870
DRAWING NO.	H340870-SITE 5B-001
REVISION	A

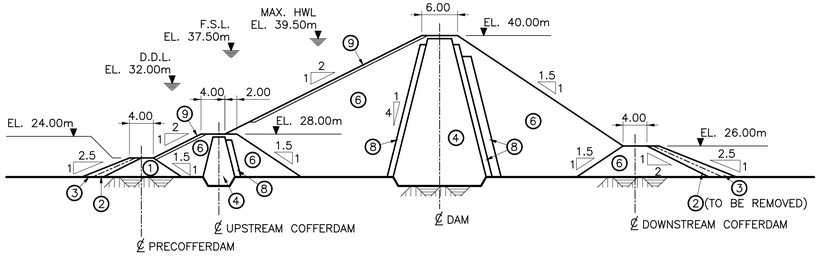
SHEET 1 OF 4



A 002 001 DAM LONGITUDINAL PROFILE

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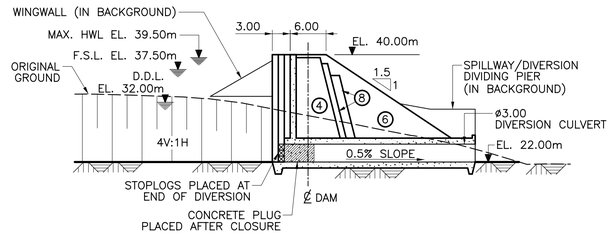
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B – – SECTION – IMPERVIOUS CORE ALTERNATIVE

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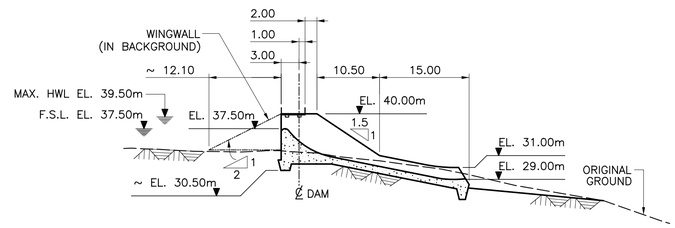
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C – – SECTION – DIVERSION CULVERTS

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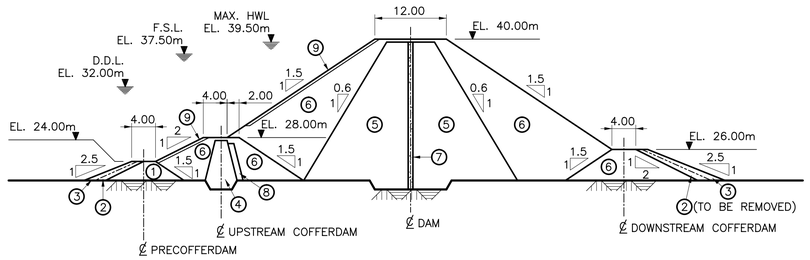
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D – – SECTION – SPILLWAY

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SCALE: 1:500



B – – SECTION – SLURRY WALL ALTERNATIVE

0m 10 20 30 40 50

SCALE: 1:500

1. DUMPED ROCKFILL
2. DUMPED IMPERVIOUS FILL
3. DUMPED RIPRAP
4. COMPACTED IMPERVIOUS FILL
5. COMPACTED TRANSITION FILL
6. COMPACTED ROCKFILL
7. CEMENT/BENTONITE (SLURRY) WALL
8. FILTERS/TRANSITION FILL
9. PLACED RIPRAP

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ST, JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: POTENTIAL STORAGE

DESIGN
PREPARED G. FRANK
CHECKED M. McFARLANE

DRAWING
PREPARED S. RUSSELL
CHECKED J. WAYE

PROJECT MANAGER
M. McFARLANE

SCALE
1:500 (D-SHEET)

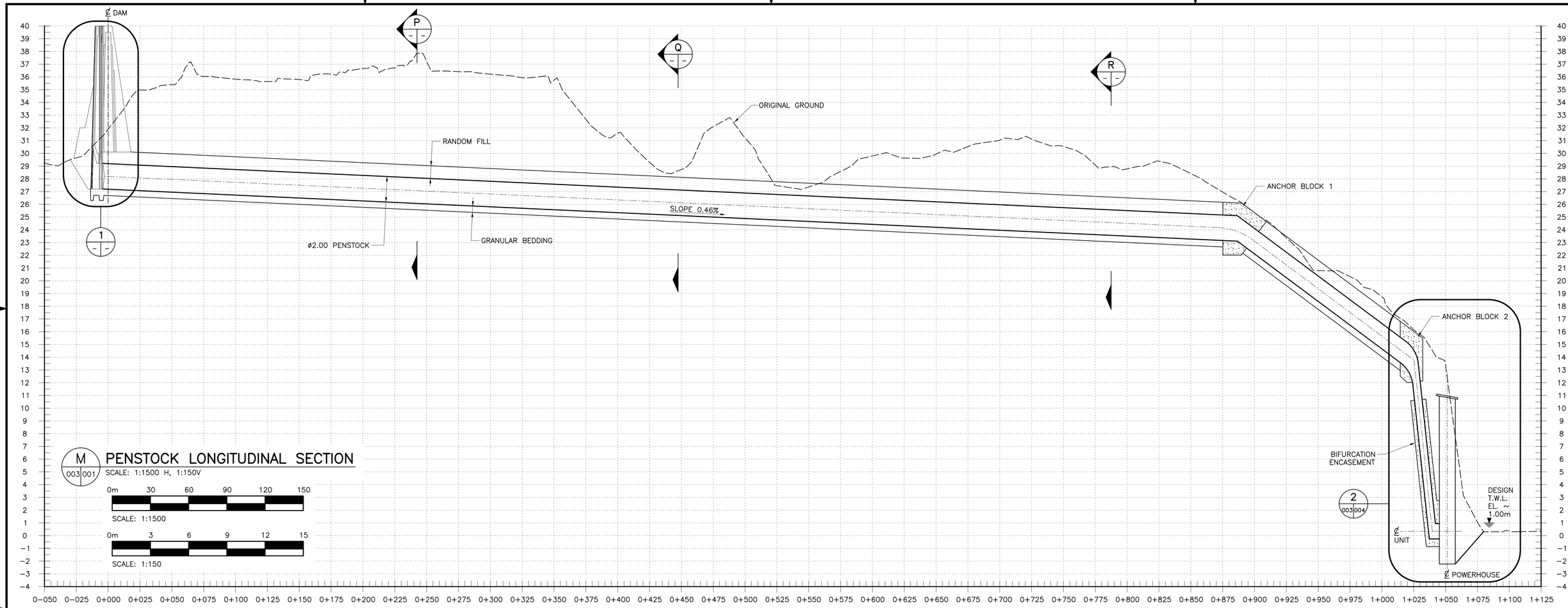
HATCH Ltd. PROJECT NO.
H340870

SITE 5B – HEADWORKS PROFILE AND SECTIONS

DRAWING NO.
H340870-SITE 5B-002

REVISION
A

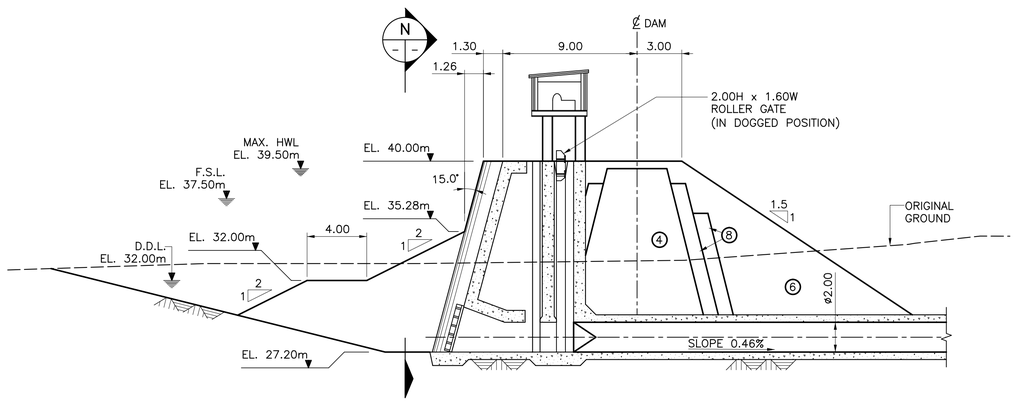
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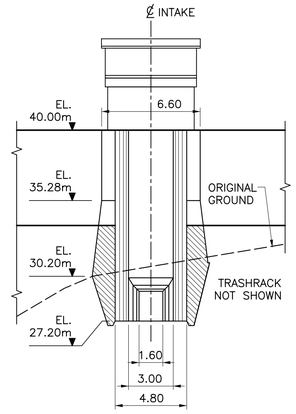
M 003|001 PENSTOCK LONGITUDINAL SECTION
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SCALE: 1:1500

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SCALE: 1:150

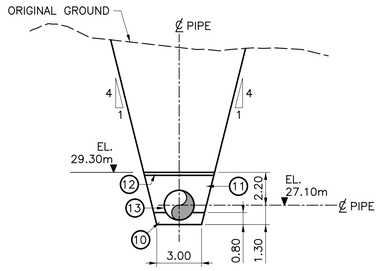


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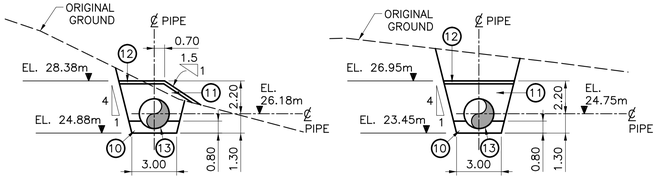


N − − INTAKE − FRONT ELEVATION
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SCALE: 1:200

4 COMPACTED IMPERVIOUS FILL
6 COMPACTED ROCKFILL
8 FILTERS/TRANSITION FILL
10 FINE GRANULAR BEDDING (WELL COMPACTED)
11 GRAVEL BACKFILL (THERMAL INSULATION)
12 RIPRAP
13 ø2.00 PENSTOCK



P 003|001 SECTION
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SCALE: 1:200



Q 003|001 SECTION

R 003|001 SECTION

0m 4 8 12 16 20
SCALE: 1:200

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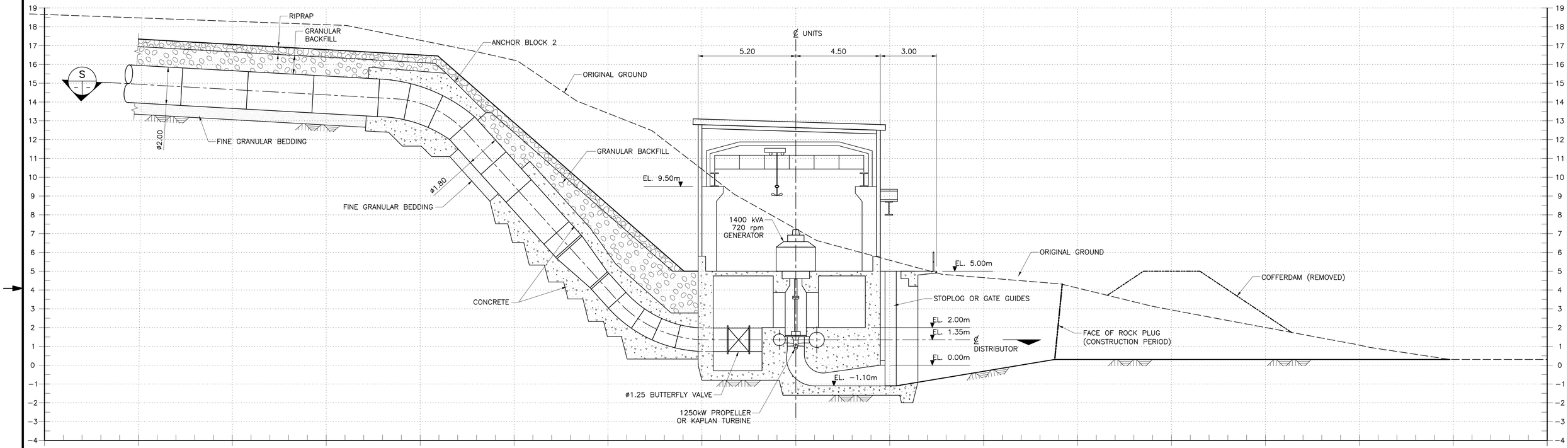
NL HYDRO
ST. JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: POTENTIAL STORAGE

SITE 5B −
PROFILE AND SECTIONS

DESIGN
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CHECKED M. McFARLANE
DRAWING
PREPARED S. RUSSELL
CHECKED J. WAYE
PROJECT MANAGER
M. McFARLANE
SCALE
AS SHOWN (D−SHEET)
HATCH Ltd. PROJECT NO.
H340870

DRAWING NO.
H340870−SITE 5B−003
REVISION
A
SHEET 3 OF 4

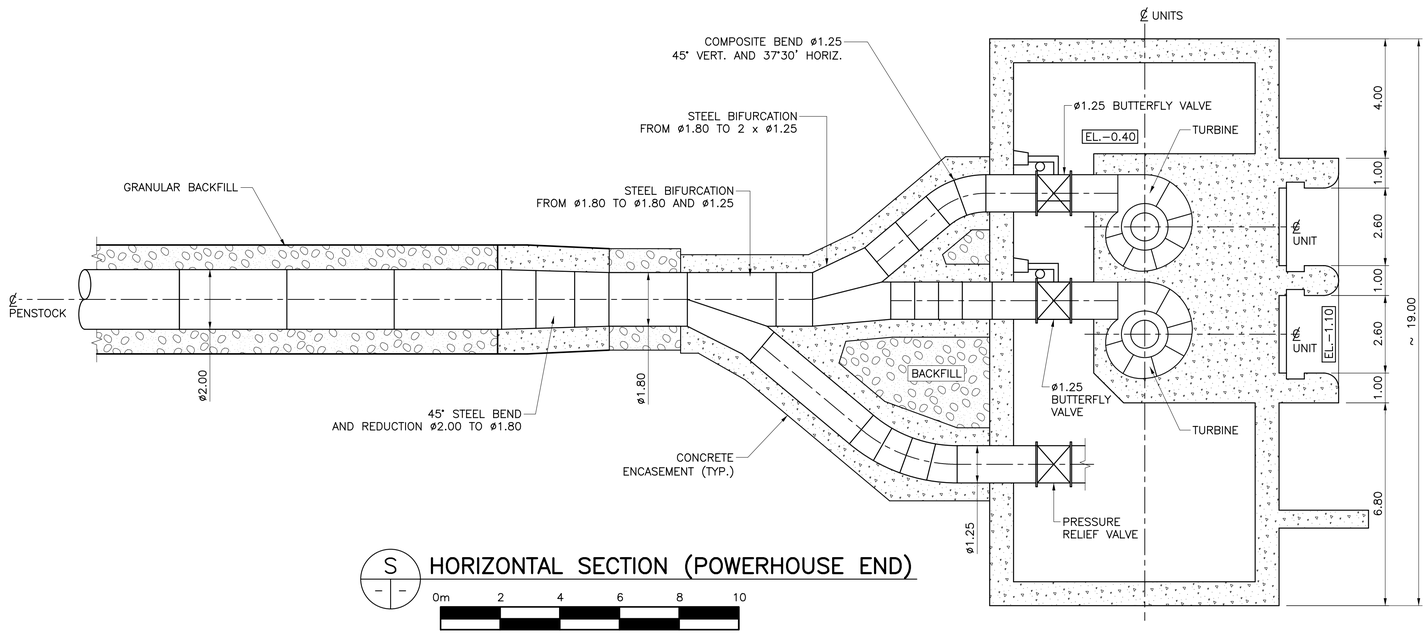


2 LONGITUDINAL SECTION (POWERHOUSE END)

004|003

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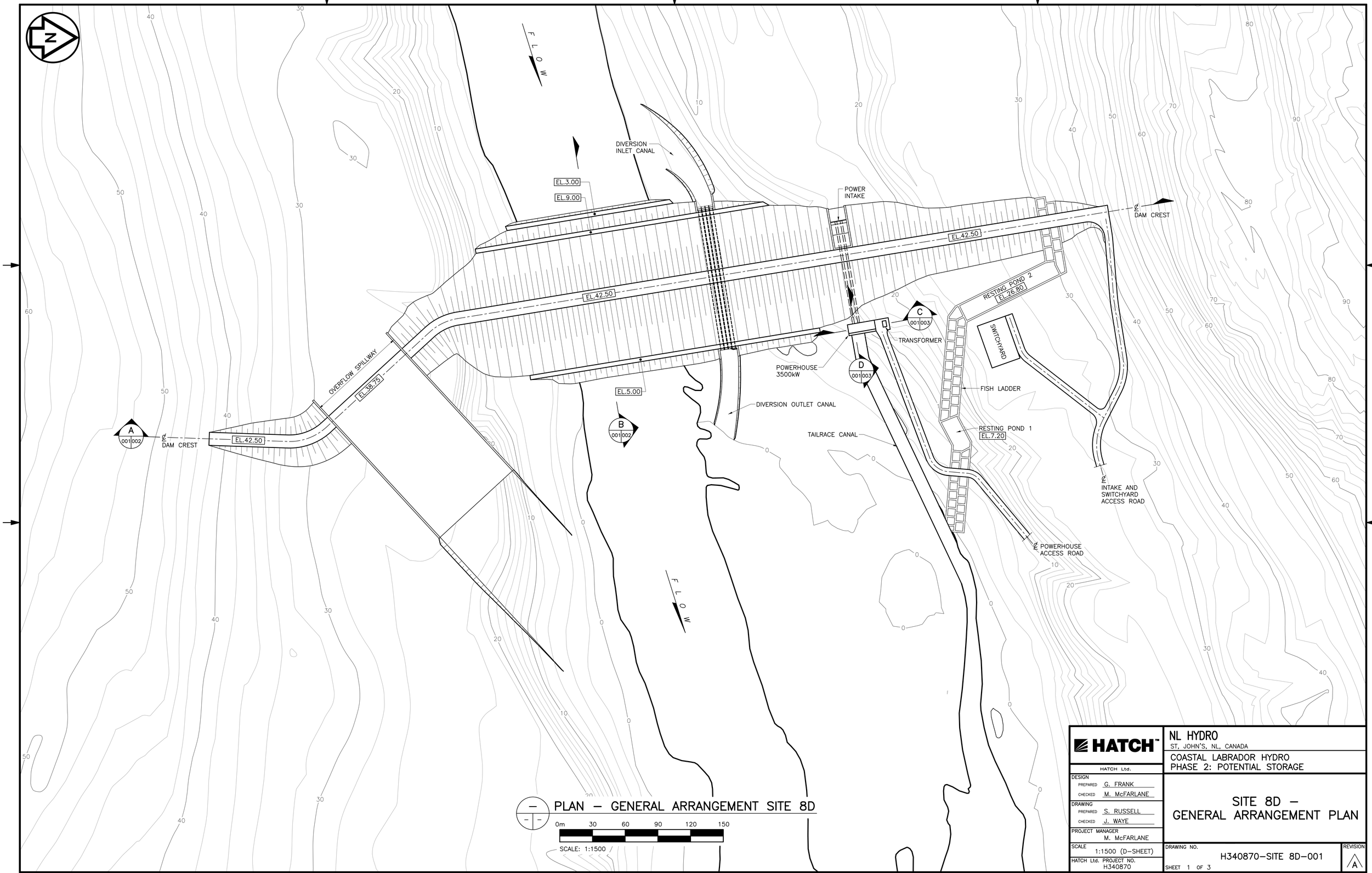


S HORIZONTAL SECTION (POWERHOUSE END)

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SCALE: 1:100

HATCH Ltd.	NL HYDRO ST. JOHN'S, NL, CANADA COASTAL LABRADOR HYDRO PHASE 2: POTENTIAL STORAGE
DESIGN PREPARED G. FRANK CHECKED M. McFARLANE DRAWING PREPARED S. RUSSELL CHECKED J. WAYE PROJECT MANAGER M. McFARLANE SCALE 1:100 (D-SHEET) HATCH Ltd. PROJECT NO. H340870	SITE 5B – POWERHOUSE PROFILE AND SECTION DRAWING NO. H340870-SITE 5B-004 REVISION A SHEET 4 OF 4



PLAN – GENERAL ARRANGEMENT SITE 8D

0m 30 60 90 120 150

SCALE: 1:1500

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DESIGN PREPARED	G. FRANK
DESIGN CHECKED	M. McFARLANE
DRAWING PREPARED	S. RUSSELL
DRAWING CHECKED	J. WAYE
PROJECT MANAGER	M. McFARLANE
SCALE	1:1500 (D–SHEET)
HATCH Ltd. PROJECT NO.	H340870

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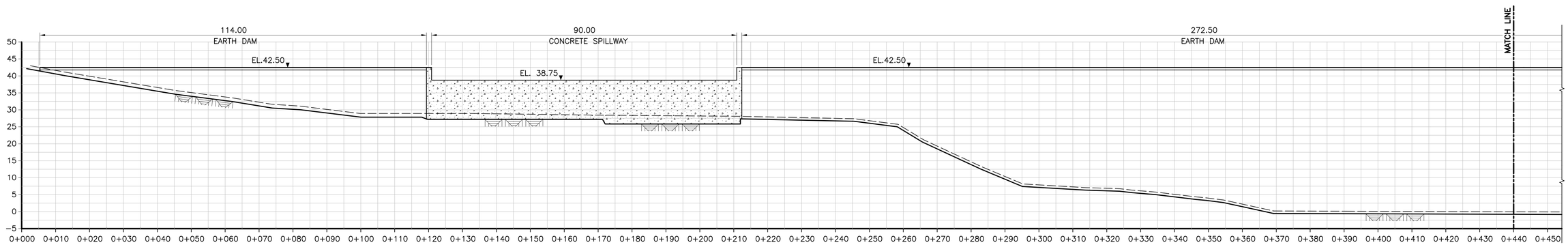
COASTAL LABRADOR HYDRO
PHASE 2: POTENTIAL STORAGE

SITE 8D – GENERAL ARRANGEMENT PLAN

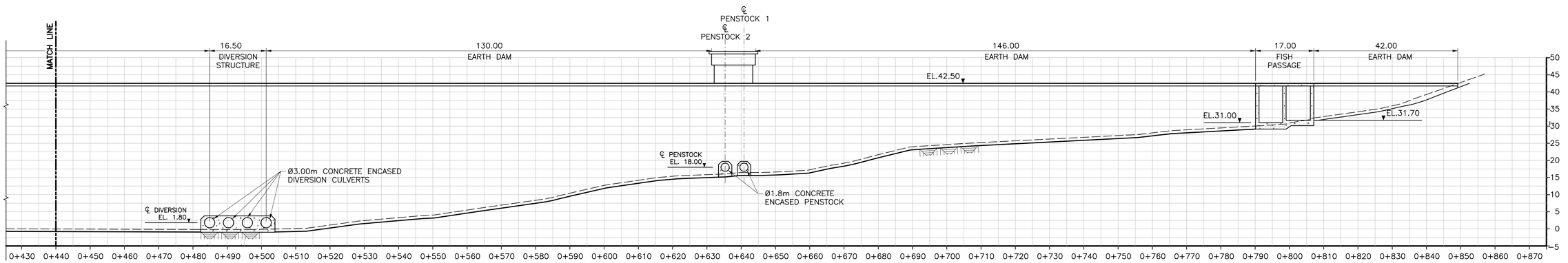
DRAWING NO. H340870–SITE 8D–001

REVISION A

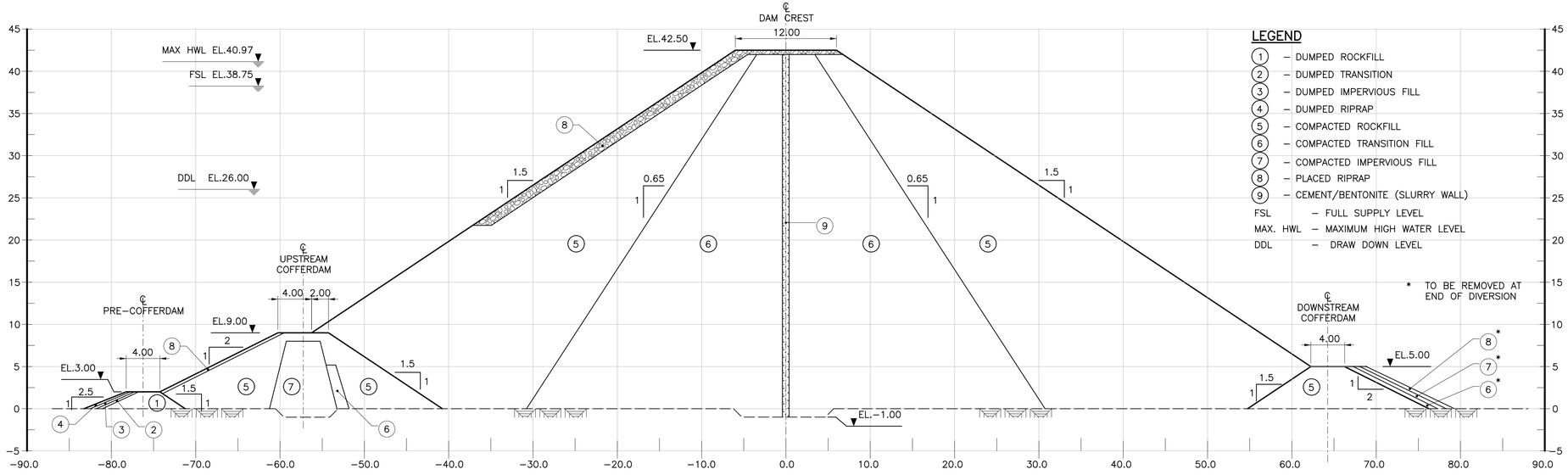
SHEET 1 OF 3



A 002 001 SECTION – MAIN DAM, SPILLWAY, DIVERSION STRUCTURE, INTAKE AND FISHPASSAGE
SCALE: 1:600



A 002 001 SECTION – MAIN DAM, SPILLWAY, DIVERSION STRUCTURE, INTAKE AND FISHPASSAGE
SCALE: 1:600



LEGEND

1. – DUMPED ROCKFILL
2. – DUMPED TRANSITION
3. – DUMPED IMPERVIOUS FILL
4. – DUMPED RIPRAP
5. – COMPACTED ROCKFILL
6. – COMPACTED TRANSITION FILL
7. – COMPACTED IMPERVIOUS FILL
8. – PLACED RIPRAP
9. – CEMENT/BENTONITE (SLURRY WALL)

FSL – FULL SUPPLY LEVEL
MAX. HWL – MAXIMUM HIGH WATER LEVEL
DDL – DRAW DOWN LEVEL

* TO BE REMOVED AT END OF DIVERSION

B 002 001 SECTION – MAIN DAM
SCALE: 1:300

0m 6 12 18 24 30
SCALE: 1:300

0m 12 24 36 48 60
SCALE: 1:600

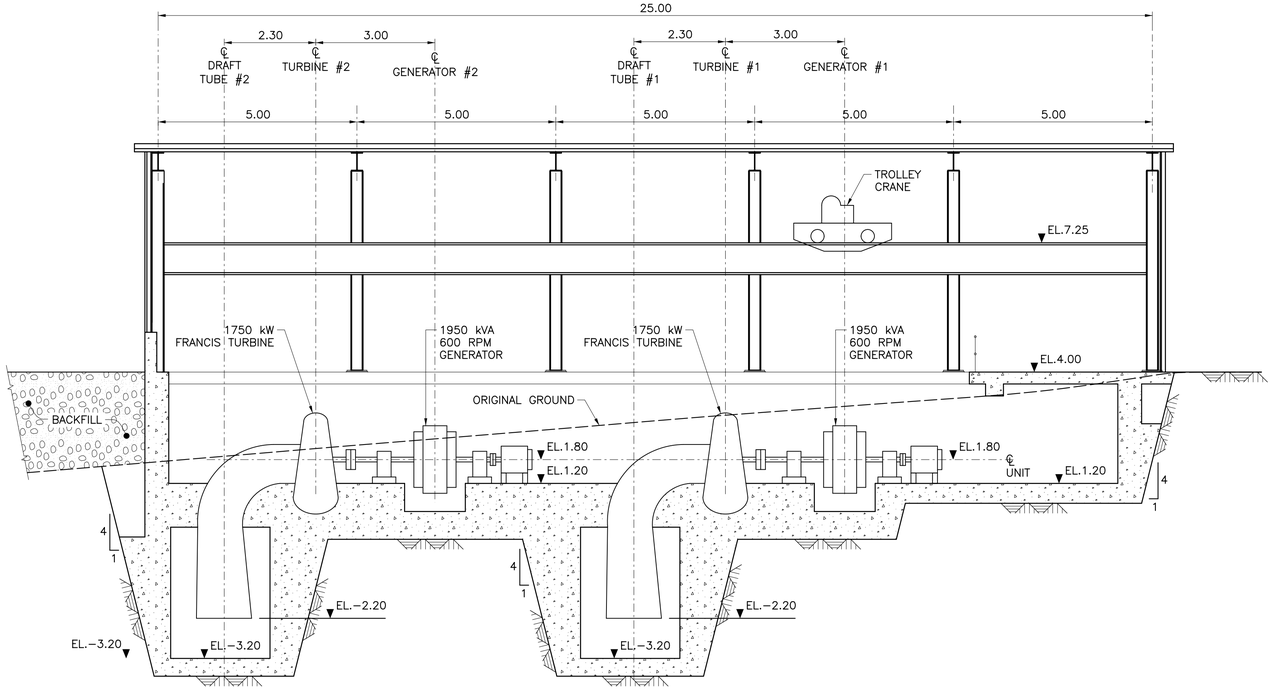
HATCH™
HATCH Ltd.

NL HYDRO
ST. JOHN'S, NL, CANADA
COASTAL LABRADOR HYDRO
PHASE 2: POTENTIAL STORAGE

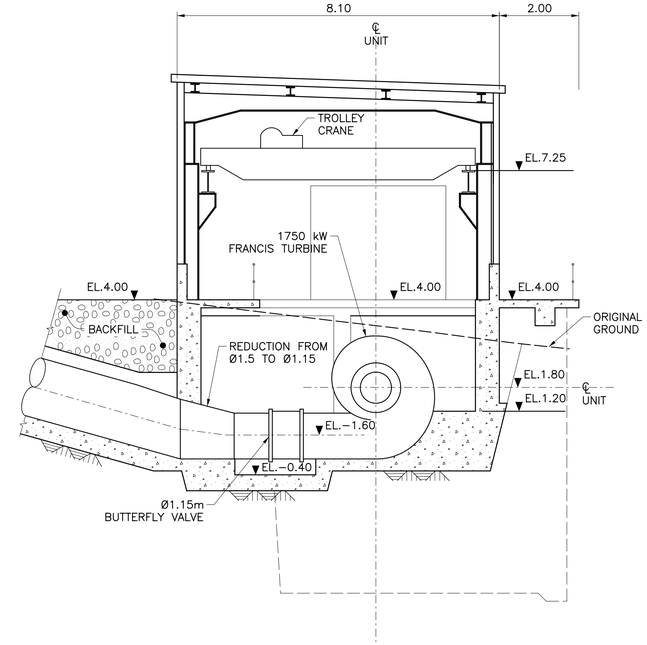
SITE 8D –
MAIN DAM SECTIONS

DESIGN
PREPARED G. FRANK
CHECKED M. McFARLANE
DRAWING
PREPARED J. WAYE
CHECKED S. RUSSELL
PROJECT MANAGER
M. McFARLANE
SCALE
AS SHOWN (D–SHEET)
HATCH Ltd. PROJECT NO.
H340870

DRAWING NO.
H340870–SITE 8D–002
SHEET 2 OF 3
REVISION
A



C SECTION – POWERHOUSE
003 001
SCALE: 1:75



D SECTION – MAIN DAM
003 001
SCALE: 1:75

0m 1.5 3.0 4.5 6.0 7.5
SCALE: 1:75

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HATCH Ltd.

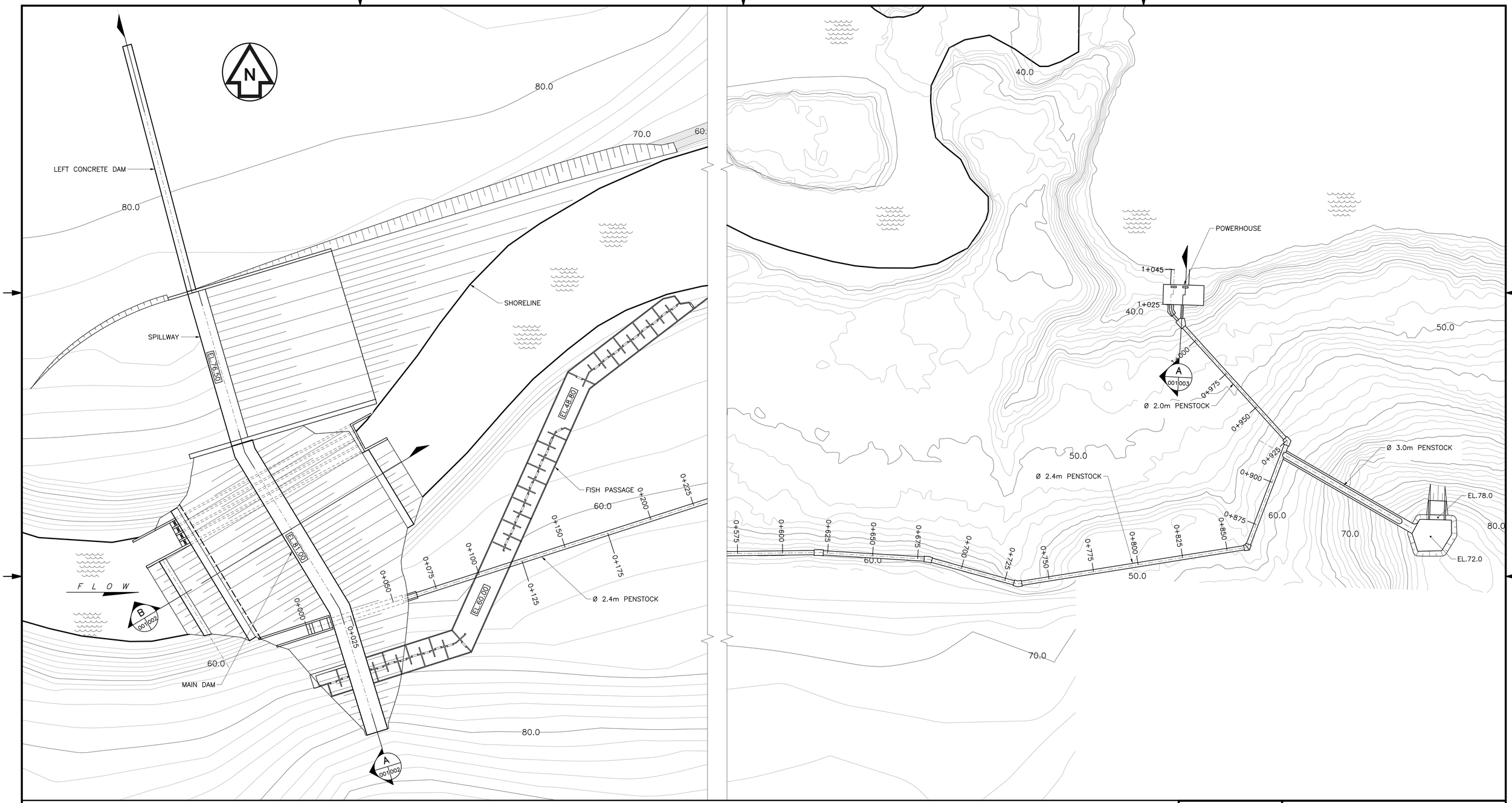
NL HYDRO
ST. JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: POTENTIAL STORAGE

SITE 8D –
POWERHOUSE SECTIONS

DESIGN
PREPARED G. FRANK
CHECKED M. McFARLANE
DRAWING
PREPARED J. WAYE
CHECKED S. RUSSELL
PROJECT MANAGER
M. McFARLANE
SCALE
AS SHOWN (D–SHEET)
HATCH Ltd. PROJECT NO.
H340870

DRAWING NO.
H340870–SITE 8D–003
SHEET 3 OF 3
REVISION
A



GENERAL ARRANGEMENT PLAN
SCALE: 1:1000

0m 20 40 60 80 100
SCALE: 1:1000

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HATCH Ltd.

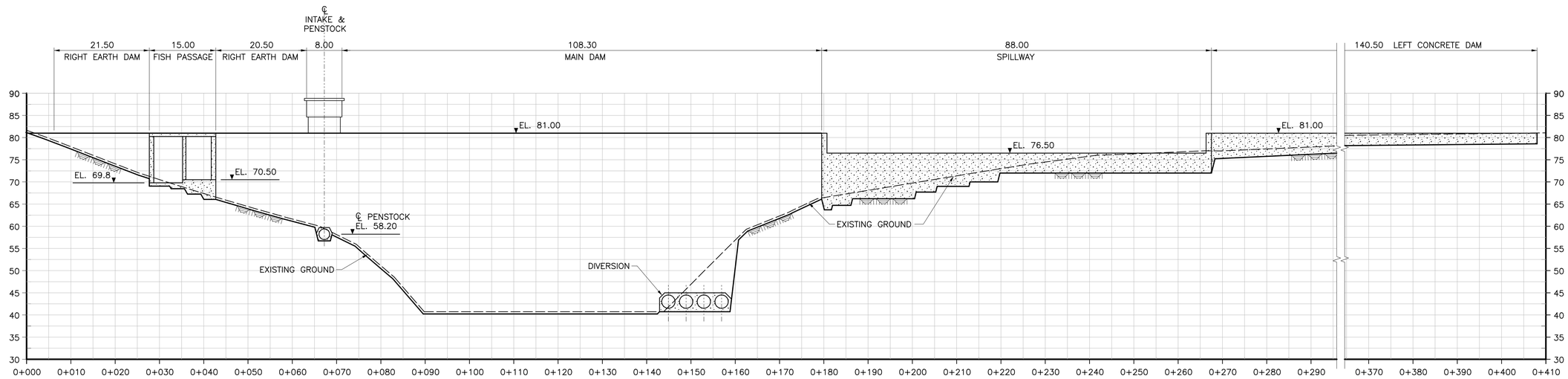
DESIGN PREPARED	G. FRANK
DESIGN CHECKED	M. McFARLANE
DRAWING PREPARED	J. WAYE
DRAWING CHECKED	S. RUSSELL
PROJECT MANAGER	M. McFARLANE
SCALE	AS SHOWN (D-SHEET)
HATCH Ltd. PROJECT NO.	H340870

NL HYDRO
ST. JOHN'S, NL, CANADA

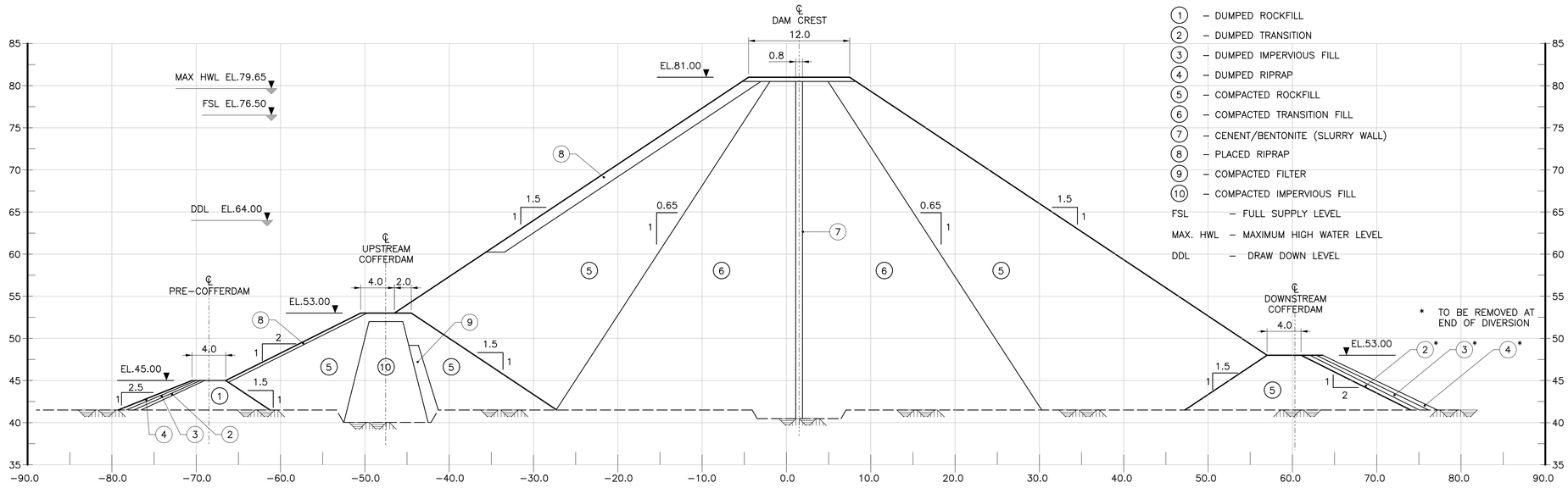
COASTAL LABRADOR HYDRO
PHASE 2: POTENTIAL STORAGE

SITE ALX B – GENERAL PLAN

DRAWING NO. H340870-SITE ALX B-001
REVISION A
SHEET 1 OF 3



A 002 001 SECTION – MAIN DAM
SCALE: 1:500



B 002 001 SECTION – MAIN DAM
SCALE: 1:300

LEGEND

1. – DUMPED ROCKFILL
2. – DUMPED TRANSITION
3. – DUMPED IMPERVIOUS FILL
4. – DUMPED RIPRAP
5. – COMPACTED ROCKFILL
6. – COMPACTED TRANSITION FILL
7. – CENENT/BENTONITE (SLURRY WALL)
8. – PLACED RIPRAP
9. – COMPACTED FILTER
10. – COMPACTED IMPERVIOUS FILL

FSL – FULL SUPPLY LEVEL
MAX. HWL – MAXIMUM HIGH WATER LEVEL
DDL – DRAW DOWN LEVEL

0m 6 12 18 24 30
SCALE: 1:300

0m 10 20 30 40 50
SCALE: 1:500

HATCH™
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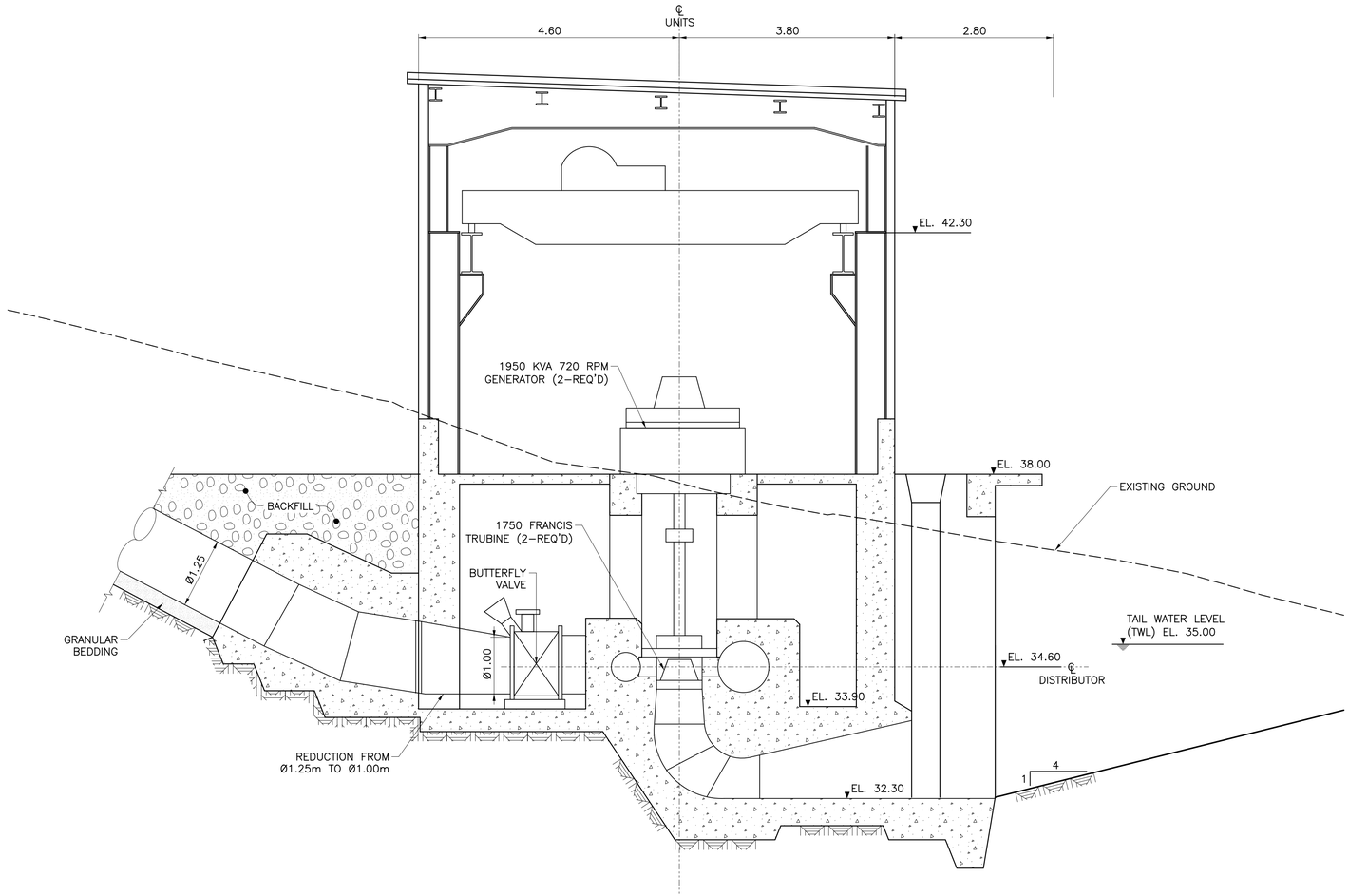
NL HYDRO
ST. JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: POTENTIAL STORAGE

SITE ALX B –
MAIN DAM SECTIONS

DESIGN PREPARED G. FRANK; CHECKED M. McFARLANE
DRAWING PREPARED J. WAYE; CHECKED S. RUSSELL
PROJECT MANAGER M. McFARLANE
SCALE AS SHOWN (D–SHEET)
HATCH Ltd. PROJECT NO. H340870

DRAWING NO. H340870–SITE ALX B– 002
REVISION A
SHEET 2 OF 3



A 003 001 SECTION – POWERHOUSE

SCALE: 1:50

0m 1 2 3 4 5

SCALE: 1:50

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HATCH Ltd.

DESIGN PREPARED	G. FRANK
DESIGN CHECKED	M. McFARLANE
DRAWING PREPARED	J. WAYE
DRAWING CHECKED	S. RUSSELL
PROJECT MANAGER	M. McFARLANE
SCALE	AS SHOWN (D–SHEET)
HATCH Ltd. PROJECT NO.	H340870

NL HYDRO
ST. JOHN'S, NL, CANADA

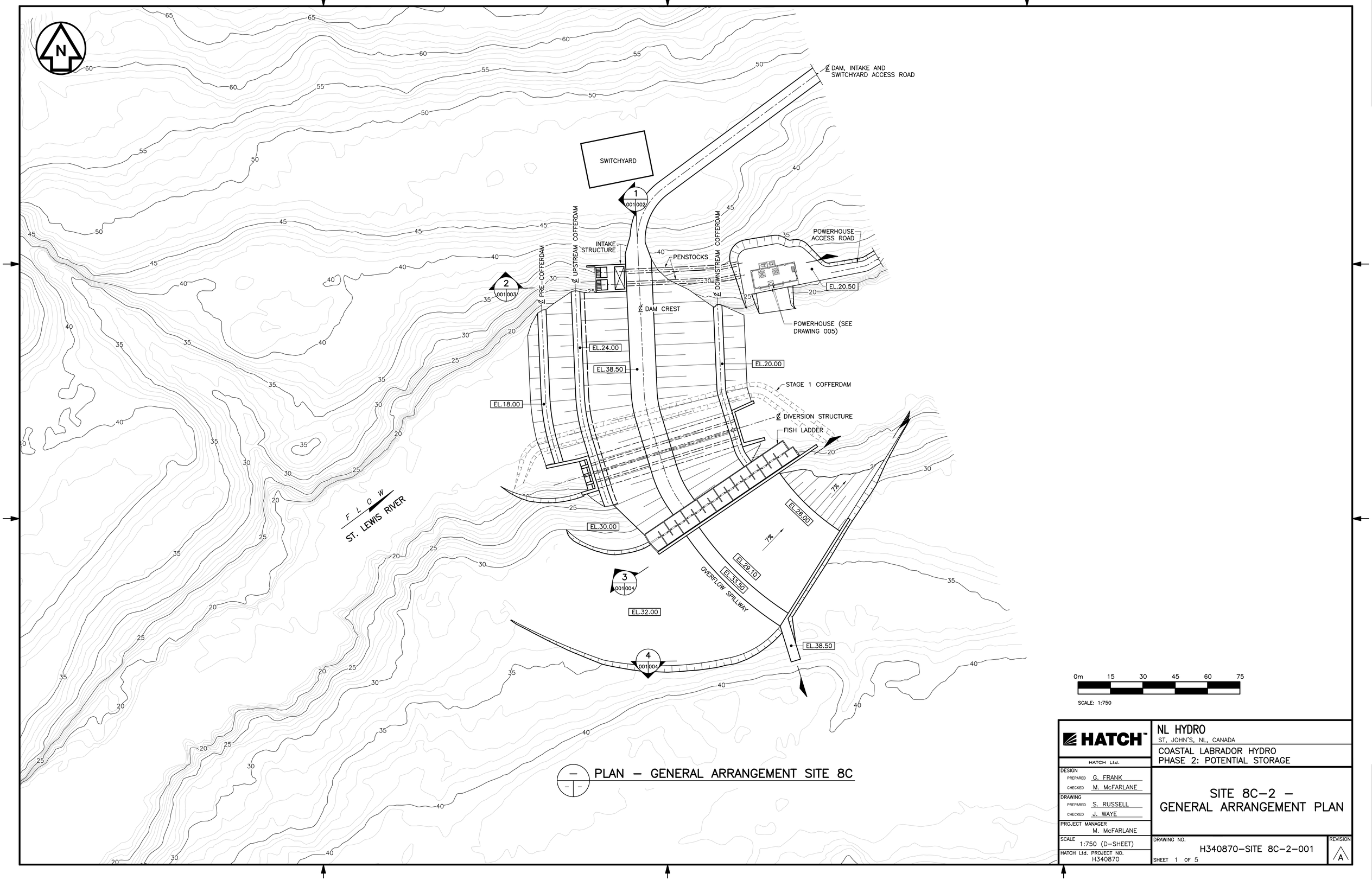
COASTAL LABRADOR HYDRO
PHASE 2: POTENTIAL STORAGE

SITE ALX B – POWERHOUSE SECTION

DRAWING NO. H340870–SITE ALX B– 003

SHEET 3 OF 3

REVISION A



PLAN – GENERAL ARRANGEMENT SITE 8C

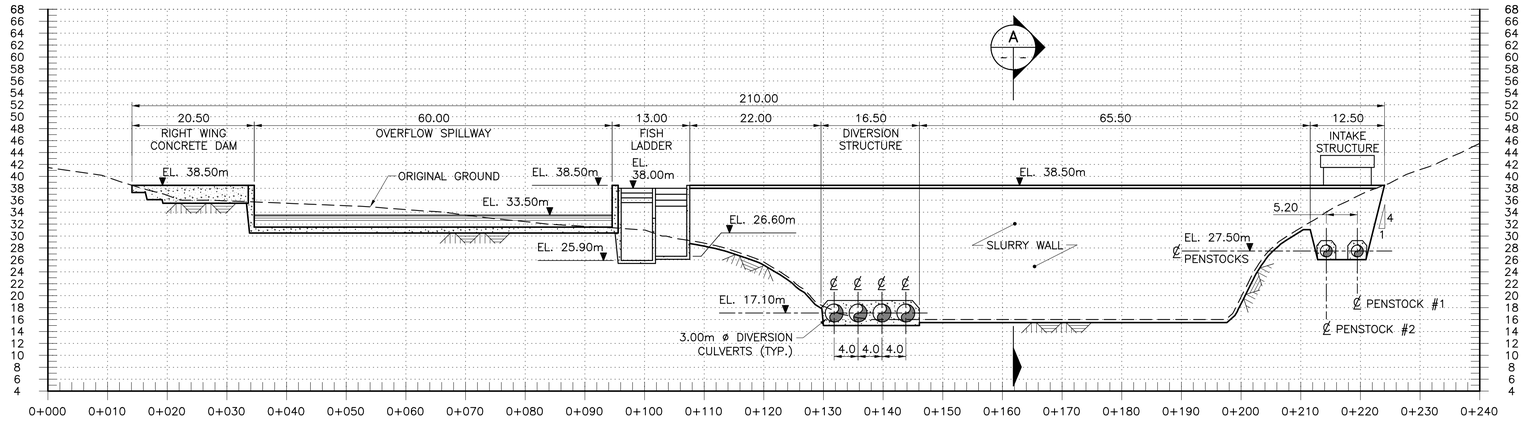
HATCH™ Ltd.

NL HYDRO
ST, JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: POTENTIAL STORAGE

SITE 8C–2 – GENERAL ARRANGEMENT PLAN

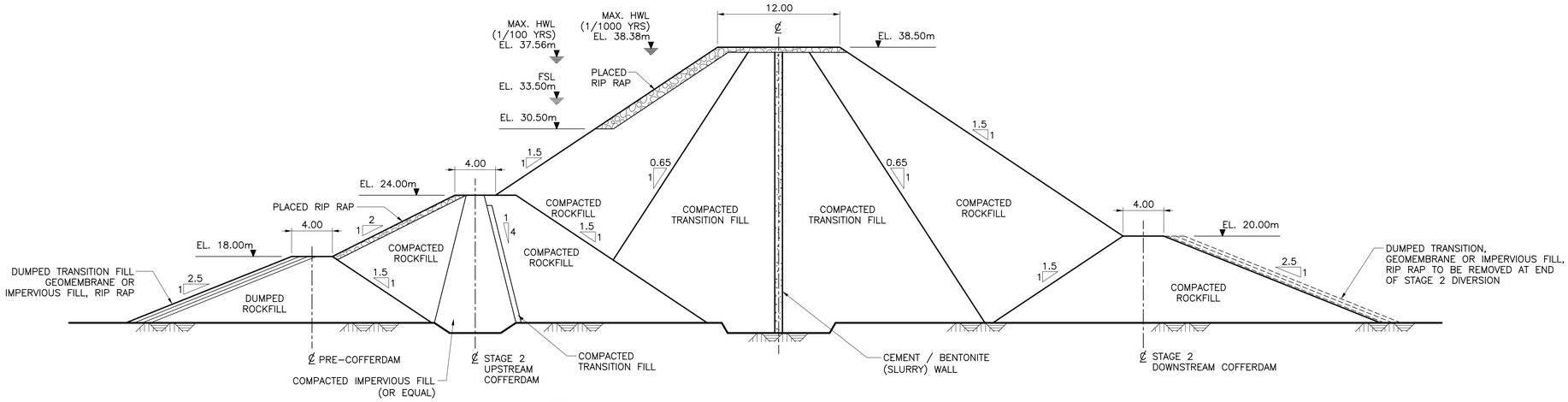
DESIGN PREPARED	G. FRANK
DESIGN CHECKED	M. McFARLANE
DRAWING PREPARED	S. RUSSELL
DRAWING CHECKED	J. WAYE
PROJECT MANAGER	M. McFARLANE
SCALE	1:750 (D–SHEET)
HATCH Ltd. PROJECT NO.	H340870
DRAWING NO.	H340870–SITE 8C–2–001
REVISION	A
SHEET	1 OF 5



1 002|001 PROFLE – RIGHT WING DAM, SPILLWAY, FISH LADDER, EMBANKMENT DAM AND INTAKE

0m 10 20 30 40 50

SCALE: 1:500



A – – SECTION – SLURRY WALL EMBANKMENT DAM

0m 5 10 15 20 25

SCALE: 1:250

HATCH

HATCH Ltd.

NL HYDRO
ST, JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: POTENTIAL STORAGE

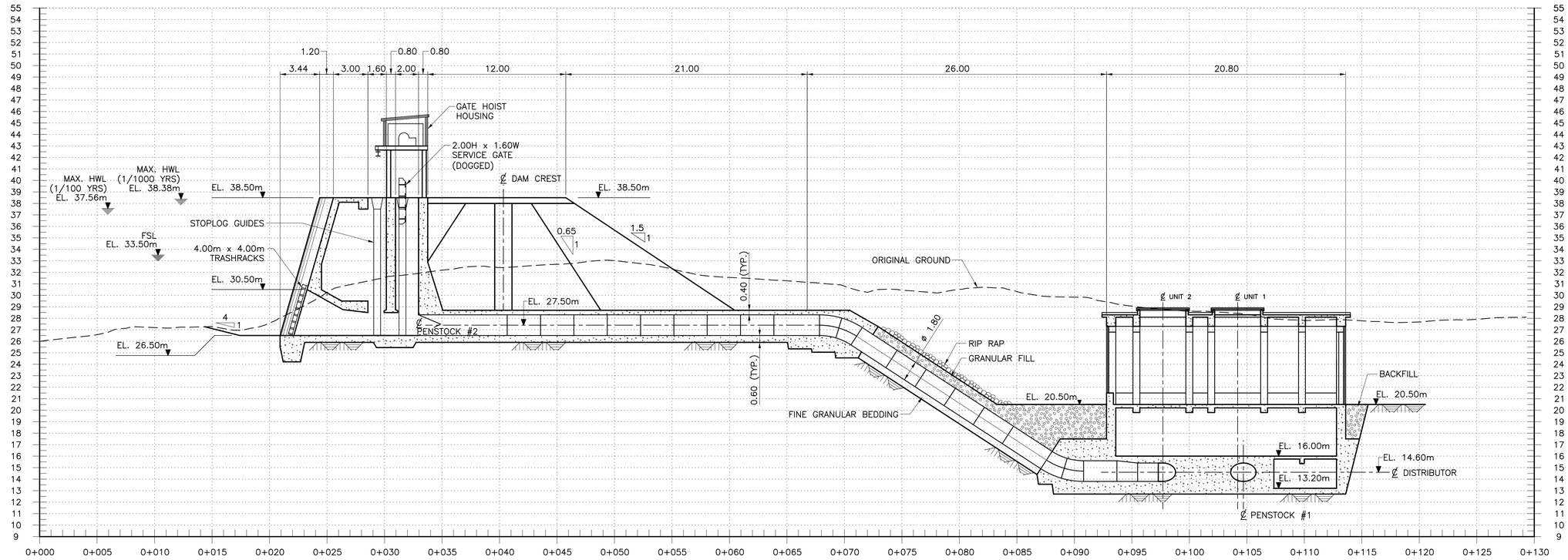
DESIGN PREPARED	G. FRANK
DESIGN CHECKED	M. McFARLANE
DRAWING PREPARED	S. RUSSELL
DRAWING CHECKED	J. WAYE
PROJECT MANAGER	M. McFARLANE
SCALE	AS SHOWN (D-SHEET)
HATCH Ltd. PROJECT NO.	H340870

SITE 8C-2 – PROFILE AND SECTION

DRAWING NO. H340870-SITE 8C-2-002

REVISION A

SHEET 2 OF 5



2
003 001

PROFILE – INTAKE, PENSTOCK, AND POWERHOUSE

0m 4 8 12 16 20

SCALE: 1:200

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DESIGN
PREPARED G. FRANK
CHECKED M. McFARLANE

DRAWING
PREPARED S. RUSSELL
CHECKED J. WAYE

PROJECT MANAGER
M. McFARLANE

SCALE
1:200 (D–SHEET)

HATCH Ltd. PROJECT NO.
H340870

NL HYDRO
ST, JOHN'S, NL, CANADA

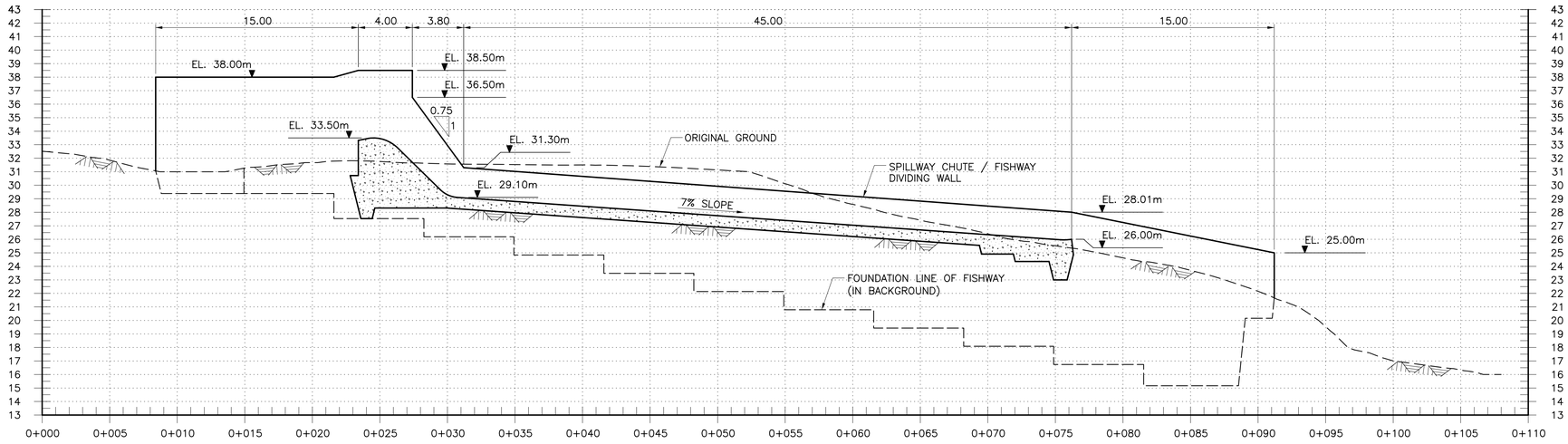
COASTAL LABRADOR HYDRO
PHASE 2: POTENTIAL STORAGE

SITE 8C–2 – INTAKE, PENSTOCK AND POWERHOUSE PROFILE

DRAWING NO.
H340870–SITE 8C–2–003

REVISION
A

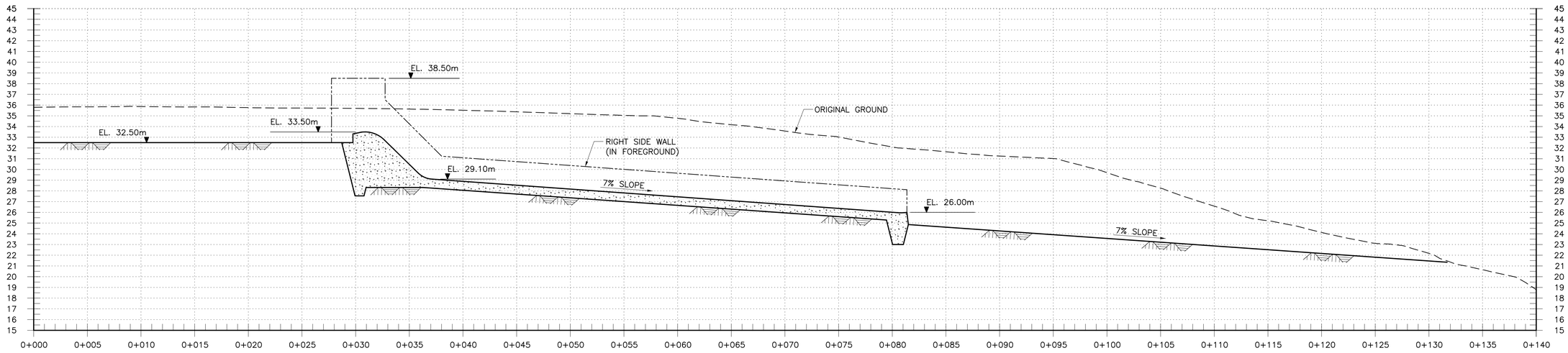
SHEET 3 OF 5



3 004 001 PROFILE – NORTH SIDE OF SPILLWAY CHUTE

0m 4 8 12 16 20

SCALE: 1:200



4 004 001 PROFILE – SOUTH SIDE OF SPILLWAY CHUTE

0m 4 8 12 16 20

SCALE: 1:200

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HATCH Ltd.

DESIGN
PREPARED G. FRANK
CHECKED M. McFARLANE

DRAWING
PREPARED S. RUSSELL
CHECKED J. WAYE

PROJECT MANAGER
M. McFARLANE

SCALE
1:200 (D–SHEET)

HATCH Ltd. PROJECT NO.
H340870

NL HYDRO
ST. JOHN'S, NL, CANADA

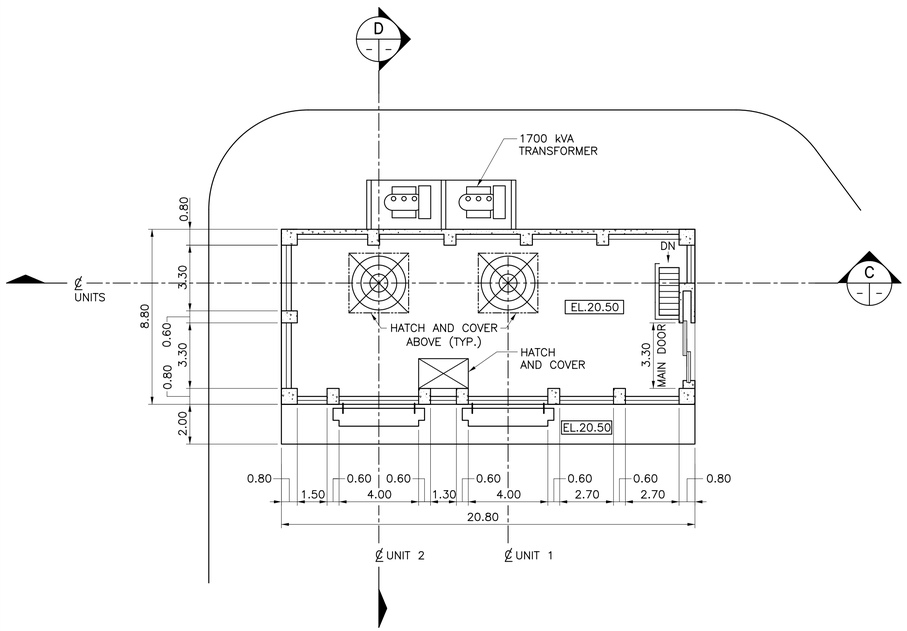
COASTAL LABRADOR HYDRO
PHASE 2: POTENTIAL STORAGE

SITE 8C–2 – SPILLWAY PROFILES

DRAWING NO.
H340870–SITE 8C–2–004

REVISION
A

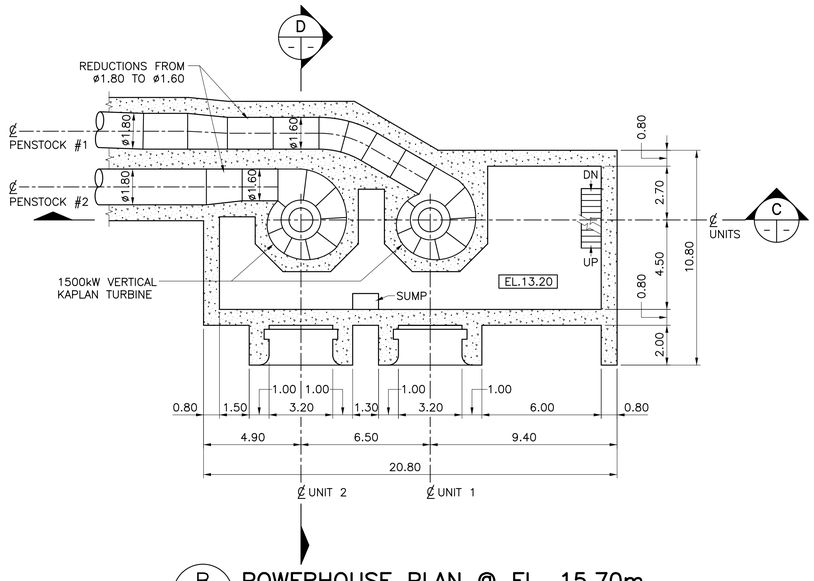
SHEET 4 OF 5



A POWERHOUSE PLAN @ EL. 23.00m

0m 3 6 9 12 15

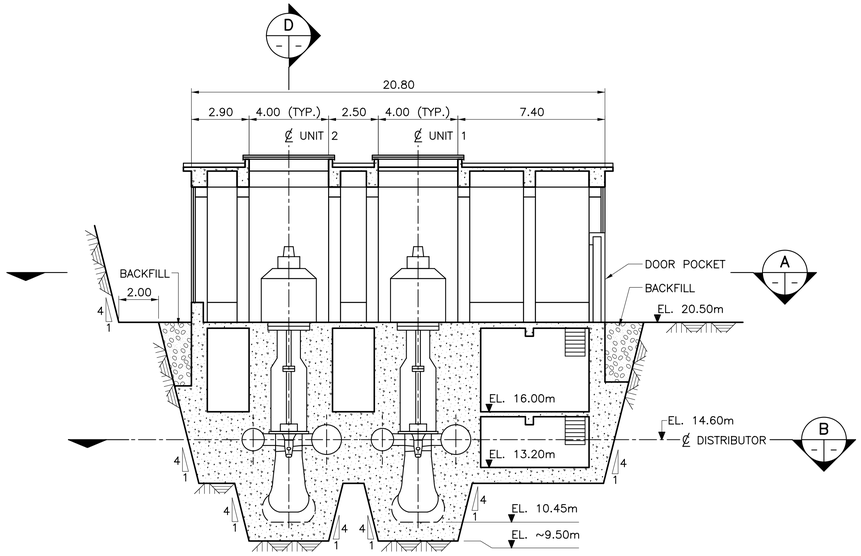
SCALE: 1:150



B POWERHOUSE PLAN @ EL. 15.70m

0m 3 6 9 12 15

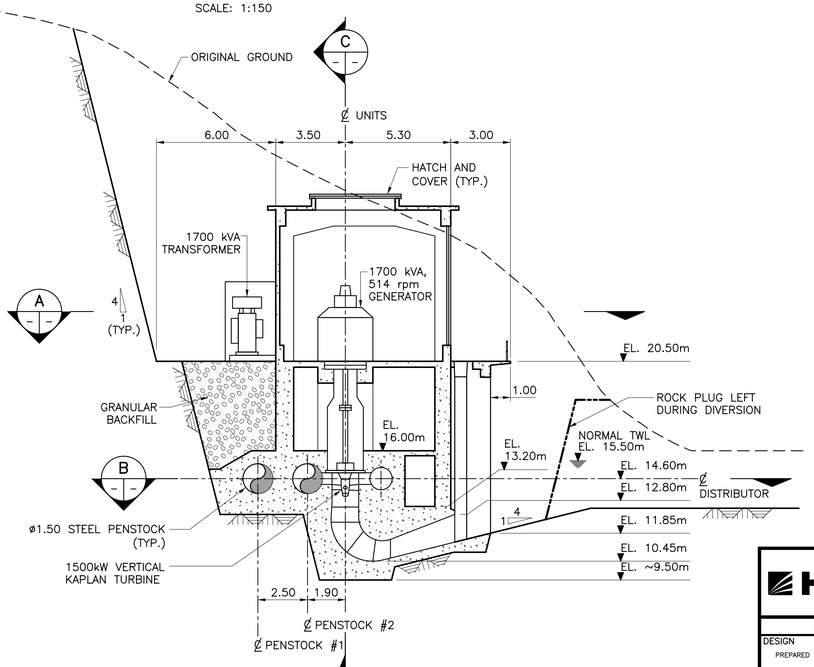
SCALE: 1:150



C SECTION – CENTERLINE OF UNITS #1 & #2

0m 3 6 9 12 15

SCALE: 1:150



D SECTION – CENTERLINE OF UNIT #2

0m 3 6 9 12 15

SCALE: 1:150

HATCH™

HATCH Ltd.

NL HYDRO
ST, JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: POTENTIAL STORAGE

SITE 8C–2 – POWERHOUSE SECTIONS

DESIGN
PREPARED G. FRANK
CHECKED M. McFARLANE
DRAWING
PREPARED S. RUSSELL
CHECKED J. WAYE
PROJECT MANAGER
M. McFARLANE
SCALE
1:150 (D–SHEET)
HATCH Ltd. PROJECT NO.
H340870

DRAWING NO.
H340870–SITE 8C–2–005
REVISION
A
SHEET 5 OF 5

REVISION
#

DWG. NO.
##########

CHARLOTTETOWN

EXISTING EQUIPMENT (NOTE 1)

STANDBY DIESEL GENERATOR SETS

52 52 52 52

SPLITTER

LA

M

52

TRANSFORMER 34.5:4.16kV 1.8MVA (NOTE 2)

TRANSFORMER 600V:4.16kV

TRANSFORMER 600V:4.16kV

52

52

4.16kV

LOADS

PORT HOPE SIMPSON

EXISTING EQUIPMENT (NOTE 1)

STANDBY DIESEL GENERATOR SETS

52 52 52

SPLITTER

LA

M

52

TRANSFORMER 34.5:4.16kV 1.8MVA (NOTE 2)

TRANSFORMER 600V:4.16kV

52

52

4.16kV

LOADS

MARY'S HARBOUR

EXISTING EQUIPMENT (NOTE 1)

STANDBY DIESEL GENERATOR SETS

52 52 52

SPLITTER

LA

M

52

TRANSFORMER 34.5:4.16kV 1.8MVA (NOTE 2)

TRANSFORMER 600V:4.16kV

52

52

4.16kV

LOADS

ST. LEWIS

EXISTING EQUIPMENT (NOTE 1)

STANDBY DIESEL GENERATOR SETS

52 52 52

SPLITTER

LA

M

52

TRANSFORMER 34.5:4.16kV 1.8MVA (NOTE 2)

TRANSFORMER 600V:4.16kV

52

52

4.16kV

LOADS

12km

477kcmil

477kcmil 21km (NOTE 3)

477kcmil 0km

(NOTE 4)

477kcmil 14km

(NOTE 4)

477kcmil 8km

477kcmil 26km

477kcmil 31km

477kcmil 10km

SITE 5B

LA LA

M M

52

TRANSFORMER 34.5/4.16kV 3MVA

4.16kV

52 52 52

1250kW 4.16kV 3PH, 60Hz

EXCITATION

G1

G2

1250kW 4.16kV 3PH, 60Hz

EXCITATION

STATION SERVICES TRANSFORMER 4160:600V

STANDBY DIESEL GENERATOR (NOTE 5)

CLOSED TRANSITION AUTO TRANSFER SWITCH

N.C. N.O.

LOADS

SITE 8C

LA

M

52

TRANSFORMER 34.5/4.16kV 4MVA

4.16kV

52 52 52

1500kW 4.16kV 3PH, 60Hz

EXCITATION

G1

G2

1500kW 4.16kV 3PH, 60Hz

EXCITATION

STATION SERVICES TRANSFORMER 4160:600V

STANDBY DIESEL GENERATOR (NOTE 5)

CLOSED TRANSITION AUTO TRANSFER SWITCH

N.C. N.O.

LOADS

NOTES:

1. EXISTING DIESEL PLANTS TO BE DE-COMMISSIONED WITH SOME CAPACITY REMAINING AS AN EMERGENCY SUPPLY.
2. DETAILS OF NEW HYDRO SERVICE SUPPLY TO BE DEVELOPED DURING THE NEXT PHASE.
3. ASSUMED VOLTAGE FOR NEW LINE IS 34.5kV.
4. SECTIONALIZER SWITCHES TO BE LOCATED BASED ON FINAL SITE DETERMINATION.
5. SIZING AND TRANSFER ARRANGEMENTS TO BE DETERMINED.

SYMBOL LEGEND:

DISCONNECT SWITCH

LOW VOLTAGE CIRCUIT BREAKER

52 CIRCUIT BREAKER

52 METALCLAD SWITCHGEAR DRAWOUT CIRCUIT BREAKER

PRELIMINARY
NOT FOR CONSTRUCTION

REV.	ISSUE FOR	AUTH. BY	DATE
B	ADDED ST. LEWIS		13-03-26
A	FOR REVIEW		12-11-23

ISSUE AUTHORIZATION

HATCH

HATCH Ltd.

DESIGN
PREPARED J. JOKIC
CHECKED R. FROUDE

DRAWING
PREPARED L. MONTEAN
CHECKED J. WAYE

PROJECT MANAGER
M. McFARLANE

SCALE
NTS (D-SHEET)

HATCH Ltd. PROJECT NO.
H340870

NL HYDRO
ST. JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: PROJECT DEFINITION PHASE

CHARLOTTETOWN, PORT HOPE SIMPSON, MARY'S HARBOUR & ST. LEWIS OPTION WITH TWO SITES – ISOLATED GRID OVERALL SINGLE LINE DIAGRAM

DRAWING NO.
H340870-0000-70-082-0001

REVISION
B

SHEET 1 OF 1

Mar 28, 2013 - 10:55am Login name: rass113134 Layout: Layout1
Drawing Name: P:\NLHYDRO\340870\CAD\E\CURRENT\H340870-0000-70-082-0001.dwg

Attachment 3

Cost Estimates and Project Schedule

Safety • Quality • Sustainability • Innovation

HATCH

Figure 6-1:

Site ALX-B (2 x 1,750 kW = 3.5 MW - Potential Storage Scheme)

Cost Estimate

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
A - Civil Works					
1	**Access Roads & Reservoir Clearing**				**$5,490,000**
1.1	Main Access Roads	km	18	$175,000	$3,150,000
1.2	PH to Dam Access Road	m	1,200	$200	$240,000
1.3	Reservoir Clearing	ha	420	$5,000	$2,100,000
2	**Cofferdams & Dewatering**				**$935,000**
2.1	Dam Cofferdams (U/S & D/S)				$737,000
2.1.1	Zone 10 Compacted Impervious Fill	m3	10,000	$30	$300,000
2.1.2	Zone 9 Filters / Transition Fill	m3	1,500	$35	$52,500
2.1.3	Zone 5 Compacted Rock Fill	m3	13,700	$25	$342,500
2.1.4	Zone 8 Riprap	m3	1,200	$35	$42,000
2.2	PH Cofferdams	m3	600	$30	$18,000
2.3	Dewatering	LS	1	$180,000	$180,000
3	**Dam Construction & River Diversion**				**$18,474,500**
3.1	**Embankment Dam Construction**				**$13,236,500**
3.2.1	Rock Excavation	m3	14,000	$40	$560,000
3.1.1	Foundation Preparation	m2	15,000	$50	$750,000
3.1.2	Zone 6 Compacted / Transition / Filter	m3	132,000	$35	$4,620,000
3.1.4	Zone 5 Compacted Rock Fill	m3	140,000	$25	$3,500,000
3.1.3	Slurry Wall (d = 1m)	m3	4,300	$850	$3,655,000
3.1.5	Zone 8 Riprap	m3	2,900	$35	$101,500
3.1.6	Roadway	m2	2,000	$25	$50,000
3.2	**Left Bank Concrete Dam**				**$1,060,000**
3.2.1	Rock Excavation	m3	1,000	$40	$40,000
3.2.2	Foundation Preparation	m2	600	$50	$30,000
3.2.3	Mass Concrete	m2	1,800	$550	$990,000
3.3	**River Diversion**				**$1,908,000**
3.3.1	Rock Excavation	m3	6,000	$40	$240,000
3.3.2	Foundation Preparation	m2	320	$50	$16,000
3.3.3	Concrete Structure (Inlet & Outlet)	m3	400	$700	$280,000
3.3.4	Wing Walls (Inlet & Outlet)	m3	300	$800	$240,000
3.3.5	Supply & Install (Ø = 3.0m) Pipe	m	440	$2,300	$1,012,000
3.3.6	Concrete Plug	m3	240	$500	$120,000
3.4	**Fish Ladder**				**$2,270,000**
3.4.1	Rock Excavation	m3	9,500	$40	$380,000
3.4.2	Concrete	m3	2,100	$900	$1,890,000
4	**Spillway (Overflow)**				**$11,904,400**
4.1	***Rock Excavation***				***$1,934,400***
4.1.1	Rock Excavation	m3	68,600	$24	$1,646,400
4.1.2	Foundation Preparation	m2	7,200	$40	$288,000
4.2	**Concrete Works**				**$9,970,000**
4.2.1	Overflow Weir	m3	3,700	$600	$2,220,000
4.2.2	Shute Slab	m3	14,800	$500	$7,400,000
4.2.3	Spillway Wing Walls	m3	500	$700	$350,000
5	**Intake and Power Conveyance**				**$7,564,200**

HATCH

Figure 6-1:

Site ALX-B (2 x 1,750 kW = 3.5 MW - Potential Storage Scheme)

Cost Estimate

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
5.1	**Intake Structure**				**$2,752,000**
5.1.1	Rock Excavation	m3	750	$40	$30,000
5.1.2	Foundation Preparation	m2	200	$50	$10,000
5.1.3	Concrete Structure	m3	1,870	$1,100	$2,057,000
5.1.4	Wing Walls	m3	650	$800	$520,000
5.1.5	Backfill	m3	3,000	$45	$135,000
5.2	**Power Conveyance (Intake Outlet to Anchor Block "S")**				**$3,360,350**
5.2.1	Rock Excavation	m3	15,300	$40	$612,000
5.2.2	Bedding Granulars	m3	2,200	$30	$66,000
5.2.3	Granular Fill	m3	6,300	$30	$189,000
5.2.4	Riprap	m3	810	$35	$28,350
5.2.5	Anchor Block	m3	650	$700	$455,000
5.2.6	Supply & Install (Ø = 2.4m) Pipe	m	900	$2,200	$1,980,000
5.2.5	Concrete under Fish Passage	m3	60	$500	$30,000
5.3	**Power Conveyance (Anchor Block "S" to Surge Chamber)**				**$407,450**
5.3.1	Rock Excavation	m3	1,300	$40	$52,000
5.3.2	Bedding Granulars	m3	150	$30	$4,500
5.3.3	Granular Fill	m3	450	$30	$13,500
5.3.4	Riprap	m3	70	$35	$2,450
5.3.5	Anchor Block	m3	200	$700	$140,000
5.3.6	Supply & Install (Ø = 3.0m) Pipe	m	75	$2,600	$195,000
5.4	**Power Conveyance (Anchor Block "S" to Powerhouse)**				**$306,400**
5.4.1	Rock Excavation	m3	850	$40	$34,000
5.4.2	Bedding Granulars	m3	120	$30	$3,600
5.4.3	Granular Fill	m3	400	$30	$12,000
5.4.4	Riprap	m3	80	$35	$2,800
5.4.5	Anchor Block ("S")	m3	120	$700	$84,000
5.4.6	Supply & Install (Ø = 2.0) Pipe	m	85	$2,000	$170,000
5.5	**Surge Chamber**				**$738,000**
5.5.1	Rock Excavation (Area)	m3	5,200	$35	$182,000
5.5.2	**Inlet Structure**				**$294,000**
5.5.2.1	Rock Excavation	m3	600	$40	$24,000
5.5.2.2	Concrete Structure	m3	300	$900	$270,000
5.5.3	**Spillway (Outlet Structure)**				**$262,000**
5.5.3.1	Rock Excavation	m3	550	$40	$22,000
5.5.3.2	Wing Walls	m3	180	$600	$108,000
5.5.3.3	Overflow Weir	m3	220	$600	$132,000
6	**Powerhouse & Substation**				**$1,382,600**
6.1	**Powerhouse Structure**				**$1,132,600**
6.1.1	Rock Excavation	m3	2,500	$40	$100,000
6.1.2	Foundation Preparation	m2	220	$80	$17,600
6.1.3	Concrete, including forms and reinforcing	m3	500	$1,100	$550,000
6.1.4	Powerhouse Superstructure	m3	1,120	$250	$280,000
6.1.5	Embedded Piping	LS	1	$75,000	$75,000
6.1.6	Handrails, Covers etc.	LS	1	$75,000	$50,000
6.1.7	Tailrace Channel	m3	1,000	$40	$50,000
6.1.8	Rock Plug	m3	200	$50	$10,000

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Figure 6-1:

Site ALX-B (2 x 1,750 kW = 3.5 MW - Potential Storage Scheme)

Cost Estimate

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
6.2	**Substation**				**$250,000**
6.2.1	Civil Works	LS	1	$250,000	$250,000
	Sub-Total - Civil Works				**$45,750,700**
B - Mechanical and Electrical Works					
1	**Gates & Hoist**				**$807,900**
1.1	**River Diversion**				**$207,500**
1.1.1	Timber Stoplogs (4 Ea)	Ea	4	$20,000	$80,000
1.1.2	Stoplogs Guides (4 Sets)	Kg	8,500	$15	$127,500
2	**Intake Structure**				**$600,400**
2.1	Trashrack & Guides	kg	3,600	$15	$54,000
2.2	Intake Stoplogs & Guides	kg	7,200	$17	$122,400
2.3	Roller Gate & Gate Guides	kg	14,400	$20	$288,000
2.4	Gate Hoists	Ea	1	$40,000	$40,000
2.5	Hoist for Stoplog & Gate	kg	4,800	$20	$96,000
3	**Powerhouse M&E**				**$5,111,000**
3.1	**PH Water to Wire Equipment**				**$4,200,000**
3.1.1	Supply Water to Wire (W2W) Equipment	LS	1	$3,000,000	$3,000,000
3.1.2	Delivery W2W Equipment to Site	LS	1	$200,000	$200,000
3.1.3	Installation W2W Equipment	LS	1	$1,000,000	$1,000,000
3.2	**Auxiliary Mechanical System**				**$425,000**
3.2.1	Drainage & Dewatering Systems	LS	1	$50,000	$50,000
3.2.2	Fire Protection System	LS	1	$25,000	$25,000
3.2.3	Domestic & Service Water Systems	LS	1	$50,000	$50,000
3.2.4	HVAC Station System	LS	1	$95,000	$95,000
3.2.5	Piezometer Piping	LS	1	$15,000	$15,000
3.2.6	Compressed Air System	LS	1	$40,000	$40,000
3.2.7	P/H Crane (15 Tonne)	LS	1	$150,000	$150,000
3.3	**Auxiliary Electrical System**				**$170,000**
3.3.1	PH Cable Trays & Embedded Piping	LS	1	$20,000	$20,000
3.3.2	LV Power & Control cables	LS	1	$50,000	$50,000
3.3.3	PH Fire Alarm System & Telephone Sys	LS	1	$40,000	$40,000
3.3.4	PH Grounding & Lighting	LS	1	$60,000	$60,000
3.4	**Draft Tube Closure Gates**		1		**$316,000**
3.4.1	Draft Tube Gates	Kg	12,400	$20	$248,000
3.4.2	Draft Tube Guides	Kg	4,000	$17	$68,000
4	**Substation & Transmission Lines**				**$8,840,000**
4.1	**Substation (Electrical)**				**$1,000,000**
4.1.1	Step-Up Transformer (2.0MVA, 34.5/4.16kV)	Ea	2	$200,000	$400,000
4.1.2	Transformer Protection	L.S.	1	$50,000	$50,000
4.1.3	34.5kV Metal-Clad, Outdoor Switchgear	L.S.	1	$200,000	$200,000
4.1.4	SCADA	L.S.	1	$200,000	$200,000
4.1.5	Line Disconnect Switch	L.S.	1	$50,000	$50,000
4.1.6	Interconnection with Existing DG	L.S.	1	$50,000	$50,000
4.1.7	Revenue Metering	L.S.	1	$50,000	$50,000
4.2	**Transmission Line (34.5 kV)**				**$7,840,000**
4.2.1	Supply & Install Transmission Line to PHS	km	56	$140,000	$7,840,000
	Sub-Total - Mechanical & Electrical Works				**$14,758,900**

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Figure 6-1:

Site ALX-B (2 x 1,750 kW = 3.5 MW - Potential Storage Scheme)

Cost Estimate

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
Subtotal A - Civil Works					**$45,750,700**
Subtotal B - Mechanical & Electrical Works					**$14,758,900**
Subtotal C - Construction Facilities, Indirect Cost & Northern Factor			30%	(of A + B)	**$18,152,900**
Subtotal Without Contingencies					**$78,662,500**
Contingencies					**$10,626,000**
Civil Works			20%		**$9,150,100**
Mechanical & Electrical Works			10%		**$1,475,900**
Total Estimated Construction Cost					**$89,288,500**
Environmental, Engineering, Administration and Site Inspection			7.5%		**$6,696,600**
Total Estimated Project Cost					**$95,985,100**
		Total Cost $/kW			***$27,400***

Exclusions:

Exclusions:

- escalation beyond October 2012
- taxes
- land
- isolated grid and interconnection costs

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Figure 6-2:
Site 8D (2 x 1,750 kW = 3.5 MW - Potential Storage Scheme)
Cost Estimate

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
A - Civil Works					
1	**Access Roads & Reservoir Clearing**				**$3,815,000**
1.1	Main Access Roads	km	5	$175,000	$875,000
1.2	Powerhouse Access Road	m	1,200	$200	$240,000
1.3	Reservoir Clearing	ha	270	$10,000	$2,700,000
2	**Cofferdams & Dewatering**				**$396,500**
2.1	Dam Cofferdams (U/S & D/S)				$199,000
2.1.1	Zone 4 Compacted Impervious Fill	m3	4,000	$30	$120,000
2.1.2	Zone 8 Filter / Transition Fill	m3	250	$35	$8,750
2.1.3	Zone 6 Compacted Rock Fill	m3	2,600	$25	$65,000
2.1.4	Zone 9 Riprap	m3	150	$35	$5,250
2.2	PH Cofferdams	m3	700	$25	$17,500
2.3	Dewatering	LS	1	$180,000	$180,000
3	**Embankment Dam & Diversion**				**$54,388,000**
3.1	**Dam Construction**				**$49,762,500**
3.1.1	Foundation Preparation	m2	65,000	$50	$3,250,000
3.1.2	Zone 6 Compacted Transition / Filter	m3	555,000	$35	$19,425,000
3.1.4	Zone 5 Compacted Rock Fill	m3	645,000	$25	$16,125,000
3.1.3	Slurry Wall (d=0.75m)	m3	12,500	$850	$10,625,000
3.1.5	Zone 8 Riprap	m3	5,000	$35	$175,000
3.1.6	Roadway	m2	6,500	$25	$162,500
3.2	**River Diversion**				**$2,245,500**
3.2.1	Rock Excavation	m3	6,200	$40	$248,000
3.2.2	Foundation Preparation	m2	2,600	$50	$130,000
3.2.3	Concrete Structure	m3	300	$700	$210,000
3.2.4	Wing Walls	m3	100	$800	$80,000
3.2.5	Supply & Install (Ø=3.0m) Pipe	m	500	$2,600	$1,300,000
3.2.6	Concrete Plug	m3	300	$500	$150,000
3.2.7	Diversion Stoplog & Guides	kg	7,500	$17	$127,500
3.3	***Fish Ladder***				***$2,380,000***
3.3.1	Rock Excavation	m3	10,000	$40	$400,000
3.3.2	Concrete	m3	2,200	$900	$1,980,000
4	**Spillway (Overflow)**				**$20,350,000**
4.1	Rock Excavation	m3	52,000	$30	$1,560,000
4.2	Foundation Preparation	m2	18,000	$40	$720,000
4.3	Overflow Weir	m3	17,000	$600	$10,200,000
4.4	Shute Slab	m3	13,500	$500	$6,750,000
4.5	Shute Walls	m3	600	$700	$420,000
4.6	Spillway Wing Walls	m3	1,000	$700	$700,000
5	**Intake and Power Conveyance**				**$3,011,200**
5.1	**Intake Structure**				**$2,583,500**
5.1.1	Rock Excavation	m3	500	$40	$20,000
5.1.2	Foundation Preparation	m2	350	$50	$17,500
5.1.3	Concrete Structure	m3	2,000	$1,000	$2,000,000
5.1.4	Wing Walls	m3	300	$700	$210,000
5.1.5	Backfill	m3	8,400	$40	$336,000
5.2	**Power Conveyance**				**$427,700**
5.2.1	Rock Excavation	m3	1,000	$40	$40,000
5.2.2	Bedding Granulars	m3	120	$30	$3,600

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Figure 6-2:
Site 8D (2 x 1,750 kW = 3.5 MW - Potential Storage Scheme)
Cost Estimate

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
5.2.3	Granular Fill	m3	800	$30	$24,000
5.2.4	Riprap	m3	100	$35	$3,500
5.2.5	Anchor Block	m3	125	$600	$75,000
5.2.6	Supply & Install (Ø = 1.8m) Pipe	m	160	$1,760	$281,600
6	**Powerhouse & Substation**				**$2,017,000**
6.1	**Powerhouse Structure**				**$1,817,000**
6.1.1	Rock Excavation	m3	1,200	$40	$48,000
6.1.2	Foundation Preparation	m2	300	$80	$24,000
6.1.3	Concrete, including forms and reinforcing	m3	700	$1,100	$770,000
6.1.4	Powerhouse Superstructure	m3	1,900	$250	$475,000
6.1.5	Embedded Piping & Grounding	LS	1	$75,000	$50,000
6.1.6	Handrails, Covers etc.	LS	1	$75,000	$50,000
6.1.7	Tailrace Channel	m3	10,000	$40	$400,000
6.2	**Substation**				**$200,000**
6.2.1	Civil Works	LS	1	$200,000	$200,000
	Sub-Total - Civil Works				**$83,977,700**
B - Mechanical and Electrical Works					
1	**Gates & Hoist**				**$673,000**
1.1	**River Diversion**				**$200,000**
1.1.1	Timber Stoplogs (4 Ea)	Ea	4	$20,000	$80,000
1.1.2	Stoplogs Guides (4 Sets)	Kg	8,000	$15	$120,000
2	**Intake Structure**				**$473,000**
2.1	Trashrack & Guides	kg	3,000	$15	$45,000
2.2	Intake Stoplogs & Guides	kg	6,000	$17	$102,000
2.3	Roller Gate & Gate Guides	kg	12,000	$18	$216,000
2.4	Gate Hoists	Ea	1	$30,000	$30,000
2.5	Hoist for Stoplog & Gate	kg	4,000	$20	$80,000
3	**Powerhouse M&E**				**$5,054,000**
3.1	**PH Water to Wire Equipment**				**$4,200,000**
2.1.1	Supply Water to Wire (W2W) Equipment	L.S.	1	$3,000,000	$3,000,000
2.1.2	Delivery W2W Equipment to Site	L.S.	1	$200,000	$200,000
2.1.3	Installation W2W Equipment	L.S.	1	$1,000,000	$1,000,000
3.2	**Auxiliary Mechanical System**	**L.S.**	**1**		**$425,000**
3.2.1	Drainage & Dewatering Systems	LS	1	$50,000	$50,000
3.2.2	Fire Protection System	LS	1	$25,000	$25,000
3.2.3	Domestic & Service Water Systems	LS	1	$50,000	$50,000
3.2.4	HVAC Station System	LS	1	$95,000	$95,000
3.2.5	Piezometer Piping	LS	1	$15,000	$15,000
3.2.6	Compressed Air System	LS	1	$40,000	$40,000
3.2.7	P/H Crane (15 Tonne)	LS	1	$150,000	$150,000
3.3	**Auxiliary Electrical System**				**$170,000**
3.3.1	PH Cable Trays & Embedded Piping	LS	1	$20,000	$20,000
3.3.2	LV Power & Control cables	LS	1	$50,000	$50,000
3.3.3	PH Fire Alarm System & Telephone Sys	LS	1	$40,000	$40,000
3.3.4	PH Grounding & Lighting	LS	1	$60,000	$60,000
2.5	**Draft Tube Closure Gate**				**$259,000**
3.4.1	Draft Tube Gates	Kg	10,400	$20	$208,000
3.4.2	Draft Tube Guides	Kg	3,000	$17	$51,000
3	**Substation & Transmission Lines**				**$2,875,000**

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Figure 6-2:
Site 8D (2 x 1,750 kW = 3.5 MW - Potential Storage Scheme)
Cost Estimate

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
3.1	**Substation (Electrical)**				**$1,000,000**
3.1.1	Step-Up Transformer (2MVA, 34.5/4.16kV)	Ea	2	$200,000	$400,000
3.1.2	Transformer Protection	L.S.	1	$50,000	$50,000
3.1.3	34.5kV Metal-Clad, Outdoor Switchgear, 1-Cell	L.S.	1	$200,000	$200,000
3.1.4	SCADA	L.S.	1	$200,000	$200,000
3.1.5	Line Disconnect Switch	L.S.	1	$50,000	$50,000
3.1.6	Interconnection with Existing DG	L.S.	1	$50,000	$50,000
3.1.7	Revenue Metering	L.S.	1	$50,000	$50,000
3.2	**Transmission Line (34.5 kV)**				**$1,875,000**
3.2.1	Supply & Install Transmission Line to PHS	km	13	$150,000	$1,875,000
	Sub-Total - Mechanical & Electrical Works				**$8,602,000**
Subtotal A - Civil Works					**$83,977,700**
Subtotal B - Mechanical & Electrical Works					**$8,602,000**
Subtotal C - Construction Facilities, Indirect Cost & Northern Factor			30%	(of A+B)	**$27,773,900**
Subtotal Without Contingencies					**$120,353,600**
Contingencies					**$17,655,740**
Civil Works			20%		**$16,795,540**
Mechanical & Electrical Works			10%		**$860,200**
Total Estimated Construction Cost					**$138,009,340**
Environmental, Engineering, Administration and Site Inspection			7.5%		**$10,350,700**
Total Estimated Project Cost					**$148,360,040**
	Total Cost $/kW				***$42,400***

Exclusions:

- escalation beyond October 2012
- taxes
- land
- isolated grid and interconnection costs
- financing
- Owner's costs

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Figure 6-3:
Site 5B (2 x 1,250 kW = 2.5 MW - Storage Scheme)
Cost Estimate

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
A - Civil Works					
1	**Access Roads & Reservoir Clearing**				**$5,940,000**
1.1	New Main Access Road	km	5	$175,000	$875,000
1.2	Powerhouse Access Road	m	1,200	$200	$240,000
1.3	Reservoir Clearing	ha	790	$5,000	$3,950,000
1.4	Reconstruction of Existing Road	km	5	$175,000	$875,000
2	**Cofferdams & Dewatering**				**$396,500**
2.1	Dam Cofferdams (U/S & D/S)				$199,000
2.1.1	Zone 4 Compacted Impervious Fill	m3	4,000	$30	$120,000
2.1.2	Zone 8 Filters / Transition Fill	m3	250	$35	$8,750
2.1.3	Zone 6 Compacted Rock Fill	m3	2,600	$25	$65,000
2.1.4	Zone 9 Riprap	m3	150	$35	$5,250
2.2	PH Cofferdams	m3	700	$25	$17,500
2.3	Dewatering	LS	1	$180,000	$180,000
3	**Embankment Dam, Diversion & Fish Ladder**				**$6,653,000**
3.1	**Dam Construction**				**$4,015,000**
3.1.1	Foundation Preparation	m2	10,500	$50	$525,000
3.1.2	Zone 4 Compacted Impervious Fill	m3	20,000	$30	$600,000
3.1.3	Zone 8 Filter / Transition Fill	m3	1,600	$35	$56,000
3.1.4	Zone 6 Compacted Rock Fill	m3	110,000	$25	$2,750,000
3.1.5	Zone 9 Riprap	m3	900	$35	$31,500
3.1.6	Roadway	m2	2,100	$25	$52,500
3.2	**River Diversion**				***$698,000***
3.2.1	Rock Excavation	m3	1,600	$40	$64,000
3.2.2	Foundation Preparation	m2	300	$50	$15,000
3.2.3	Bedding Materials	m3	200	$30	$6,000
3.2.4	Concrete Structure	m3	300	$700	$210,000
3.2.5	Wing Walls	m3	250	$800	$200,000
3.2.6	Backfill	m3	200	$35	$7,000
3.2.7	Supply & Install (Ø = 3.0m) Pipes	m	70	$2,300	$161,000
3.2.8	Concrete Plug	m3	70	$500	$35,000
3.3	**Fish Ladder**				***$1,940,000***
3.3.1	Rock Excavation	m3	8,000	$40	$320,000
3.3.2	Concrete	m3	1,800	$900	$1,620,000
4	**Spillway (Overflow)**				**$1,704,000**
4.1	Rock Excavation	m3	1,800	$40	$72,000
4.2	Foundation Preparation	m2	1,200	$50	$60,000
4.3	Overflow Weir	m3	1,050	$600	$630,000
4.4	Shute Slab	m3	1,100	$500	$550,000
4.5	End Walls & Mid Pier	m3	260	$800	$208,000
4.6	Spillway Wing Walls	m3	230	$800	$184,000
5	**Intake and Power Conveyance**				**$4,741,000**
5.1	**Intake Structure**				**$771,500**
5.1.1	Rock Excavation	m3	750	$40	$30,000
5.1.2	Foundation Preparation	m2	100	$50	$5,000
5.1.3	Concrete Structure	m3	600	$1,000	$600,000
5.1.4	Wing Walls	m3	120	$800	$96,000
5.1.5	Backfill	m3	900	$45	$40,500
5.2	**Power Conveyance**				**$3,969,500**

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Figure 6-3:
Site 5B (2 x 1,250 kW = 2.5 MW - Storage Scheme)
Cost Estimate

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
5.2.1	Rock Excavation	m3	30,000	$40	$1,200,000
5.2.2	Bedding Granulars	m3	1,100	$30	$33,000
5.2.3	Granular Fill	m3	9,000	$30	$270,000
5.2.4	Riprap	m3	1,500	$35	$52,500
5.2.5	Anchor Block	m3	150	$700	$105,000
5.2.6	Supply & Install (Ø = 2.0m) Pipe	m	1,020	$2,200	$2,244,000
5.2.7	Bifurcation & Steel Pipes 2 x(Ø = 1.8)	LS	1	$65,000	$65,000
6	**Powerhouse & Substation**				**$1,334,000**
6.1	**Powerhouse Structure**				**$1,184,000**
6.1.1	Rock Excavation (Structure)	m3	2,200	$40	$88,000
6.1.2	Foundation Preparation	m2	200	$80	$16,000
6.1.3	Concrete, including forms and reinforcing	m3	550	$1,100	$605,000
6.1.4	Powerhouse Superstructure	m3	1,300	$250	$325,000
6.1.5	Embedded Piping & Grounding	LS	1	$50,000	$50,000
6.1.6	Handrails, Covers etc.	LS	1	$50,000	$50,000
6.1.7	Rock Excavation (Outlet Canal)	m3	500	$100	$50,000
6.2	**Substation**				**$150,000**
6.2.1	Civil Works	LS	1	$150,000	$150,000
	Sub-Total - Civil Works				**$20,768,500**
B - Mechanical and Electrical Works					
1	**Intake Gates & Hoist**				**$672,000**
1.1	**River Diversion**				**$130,000**
1.1.1	Timber Stoplogs (2 Ea)	Ea	2	$20,000	$40,000
1.1.2	Stoplogs Guides (2 Sets)	Kg	6,000	$15	$90,000
1.2	**Intake Structure**				**$542,000**
1.2.1	Trashrack & Guides	kg	6,000	$15	$90,000
1.2.2	Intake Stoplogs & Guides	kg	6,000	$17	$102,000
1.2.3	Roller Gate & Gate Guides	kg	12,000	$20	$240,000
1.2.4	Gate Hoists	Ea	1	$30,000	$30,000
1.2.5	Hoist for Stoplog & Gate	kg	4,000	$20	$80,000
2	**Powerhouse (M&E)**				**$4,808,600**
2.1	**PH Water to Wire Equipment**				**$3,400,000**
2.1.1	Supply Water to Wire (W2W) Equipment	L.S.	1	$2,400,000	$2,400,000
2.1.2	Delivery W2W Equipment to Site	L.S.	1	$200,000	$200,000
2.1.3	Installation W2W Equipment	L.S.	1	$800,000	$800,000
2.2	**Butterfly & Pressure Relief Valve**				**$730,000**
2.2.1	2 x(Ø = 1.25m) Butterfly Valves	Ea	2	$260,000	$520,000
2.2.2	Pressure Relief Valves ((Ø = 1.25m)	Ea	1	$170,000	$170,000
2.2.3	Guard Valve & Misc Steel (Pipes, Joints)	LS	1	$40,000	$40,000
2.3	**Auxiliary Mechanical System**				**$360,000**
2.3.1	Drainage & Dewatering Systems	L.S.	1	$40,000	$40,000
2.3.2	Fire Protection System	L.S.	1	$9,500	$9,500
2.3.3	Domestic & Service Water Systems	L.S.	1	$40,000	$40,000
2.3.4	HVAC Station System	L.S.	1	$85,000	$85,000
2.3.5	Piezometer Piping	L.S.	1	$15,500	$15,500
2.3.6	Compressed Air System	L.S.	1	$20,000	$20,000
2.3.7	Powerhouse Crane (15 Tonne)	L.S.	1	$150,000	$150,000
2.4	**Auxiliary Electrical System**				**$175,000**
2.4.2	LV Power & Control Cables	L.S.	1	$30,000	$30,000

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Figure 6-3:
Site 5B (2 x 1,250 kW = 2.5 MW - Storage Scheme)
Cost Estimate

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
2.4.3	PH Grounding System	L.S.	1	$30,000	$30,000
2.4.4	Emergency Diesel Generator Set	L.S.	1	$35,000	$35,000
2.4.5	Building Services - Including Lighting System & Wiring	L.S.	1	$50,000	$50,000
2.4.6	Fire Protection and Security System	L.S.	1	$30,000	$30,000
2.5	**Draft Tube Closure Gate**				**$143,600**
2.5.1	Draft Tube Gates & Guides	kg	5,200	$18	$93,600
2.5.2	Gate Hoists	kg	2,500	$20	$50,000
3	**Substation & Transmission Lines**				**$2,600,000**
3.1	**Substation (Electrical)**				**$800,000**
3.1.1	Step-Up Transformer (1.5MVA, 34.5/4.16kV)	Ea	2	$150,000	$300,000
3.1.2	Transformer Protection	L.S.	1	$50,000	$50,000
3.1.3	34.5kV Metal-Clad, Outdoor Switchgear	L.S.	1	$150,000	$150,000
3.1.4	SCADA	L.S.	1	$150,000	$150,000
3.1.5	Line Disconnect Switch	L.S.	1	$50,000	$50,000
3.1.6	Interconnection with Existing DG	L.S.	1	$50,000	$50,000
3.1.7	Revenue Metering	L.S.	1	$50,000	$50,000
3.2	**Transmission Line (34.5 kV)**				**$1,800,000**
3.2.1	Supply & Install Transmission Line to CHT	km	12	$150,000	$1,800,000
	Sub-Total - Mechanical & Electrical Works				**$8,080,600**
Subtotal A - Civil Works					**$20,768,500**
Subtotal B - Mechanical & Electrical Works					**$8,080,600**
Subtotal C - Construction Facilities, Indirect Cost & Northern Factor			30%	(of A+B)	**$8,654,700**
Subtotal Without Contingencies					**$37,503,800**
Contingencies					**$4,961,800**
Civil Works			20%		**$4,153,700**
Mechanical & Electrical Works			10%		**$808,100**
Total Estimated Construction Cost					**$42,465,600**
Environmental, Engineering, Administration and Site Inspection			7.5%		**$3,184,900**
Total Estimated Project Cost					**$45,650,500**
	Total Cost $/kW				***$18,300***

Exclusions:

- escalation beyond October 2012
- taxes
- land
- isolated grid and interconnection costs
- financing

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Figure 6-4:
Site 8C-2 (2 x 1,500 kW = 3.0 MW - Run-of-River Project)
Cost Estimate

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
A - Civil Works					
1	**Access Roads & Reservoir Clearing**				**$2,250,000**
1.1	Main Access Roads	km	10	$175,000	$1,750,000
1.2	Powerhouse Access Road	m	1,000	$200	$200,000
1.3	Reservoir Clearing	ha	20	$15,000	$300,000
2	**Cofferdams & Dewatering**				**$930,000**
2.1	Stage 1 & 2 Cofferdams	m3	25,000	$30	$750,000
2.2	Dewatering	LS	1	$180,000	$180,000
3	**Embankment Dam, Diversion & Fish Ladder**				**$8,527,500**
3.1	***Dam Construction***				***$4,870,000***
3.1.1	Rock Excavation	m3	1,200	$40	$48,000
3.1.2	Foundation Preparation	m2	10,500	$50	$525,000
3.1.3	Compacted Fill (Transition)	m3	42,000	$35	$1,805,000
3.1.4	Slurry Wall (d = 0.75m)	m3	1,700	$850	$1,445,000
3.1.5	Random Compacted Rockfill	m3	37,500	$25	$937,500
3.1.6	Riprap	m3	2,200	$35	$77,000
3.1.7	Roadway	m2	1,300	$25	$32,500
3.2	**River Diversion**				***$1,387,500***
3.2.1.1	Rock Excavation	m3	200	$40	$8,000
3.2.1.2	Foundation Preparation	m2	320	$50	$16,000
3.2.2.2	Bedding Materials	m3	650	$30	$19,500
3.2.2.3	Supply & Install (Ø = 3.0m) Pipes	m	300	$2,300	$690,000
3.2.1.3	Concrete Structures	m3	680	$800	$544,000
3.2.1.4	Backfill	m3	1,000	$35	$35,000
3.2.2.4	Concrete Plug (at Slurry Wall)	m3	150	$500	$75,000
3.3	***Fish Ladder***				***$2,270,000***
3.3.1	Rock Excavation	m3	9,500	$40	$380,000
3.3.2	Concrete	m3	2,100	$900	$1,890,000
4	**Spillway (Overflow)**				**$3,655,000**
4.1	***Rock Excavation***				***$1,175,000***
4.1.1	Approach Channel	m3	12,000	$30	$360,000
4.1.2	Rock Excavation	m3	16,000	$40	$640,000
4.1.3	Foundation Preparation	m2	3,500	$50	$175,000
4.2	***Concrete Works***				***$2,480,000***
4.2.1	Overflow Weir	m3	1,200	$600	$720,000
4.2.2	Wing Walls	m3	1,200	$800	$960,000
4.2.3	Chute Slab	m3	1,250	$500	$625,000
4.2.4	Chute Walls	m3	250	$700	$175,000
5	**Intake and Power Conveyance**				**$1,072,500**
5.1	***Intake Structure***				***$542,500***
5.1.1	Rock Excavation	m3	1,500	$40	$60,000
5.1.2	Surface Preparation	m2	200	$50	$10,000
5.1.3	Concrete	m3	450	$1,000	$450,000
5.1.4	Backfill	m3	500	$45	$22,500
	Power Conveyance Pipe				**$530,000**
5.2	Rock Excavation	m3	5,000	$40	$200,000
5.2.1	Surface Preparation	m2	400	$50	$20,000
5.2.2	Penstock (Ø = 1.80m) Pipe	m	120	$2,000	$240,000
5.2.3	Anchor Block & Concrete Encasement	m3	100	$700	$70,000

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Figure 6-4:
Site 8C-2 (2 x 1,500 kW = 3.0 MW - Run-of-River Project)
Cost Estimate

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
6	**Powerhouse & Substation**				**$2,445,000**
6.1	***Powerhouse Structure***				**$1,995,000**
6.1.1	Rock Excavation	m3	8,500	$40	$340,000
6.1.2	Surface Preparation	m2	375	$80	$30,000
6.1.3	Concrete, including forms and reinforcing	m3	1,000	$1,100	$1,100,000
6.1.4	Powerhouse Superstructure	m3	1,500	$250	$375,000
6.1.5	Embedded Piping	LS	1	$75,000	$75,000
6.1.6	Miscellanies Steel	LS	1	$75,000	$75,000
6.2	***Powerhouse Area***				***$200,000***
6.2.1	Rock Excavation	m3	5,000	$40	$200,000
6.3	***Substation***				***$250,000***
6.3.1	Civil Works	LS	1	$250,000	$250,000
	Sub-Total - Civil Works				**$18,880,000**
B - Mechanical and Electrical Works					
1	**Gates & Hoist**				**$900,300**
1.1	**River Diversion**				**$245,000**
1.1.1	Timber Stoplogs (4 Ea)	Ea	4	$20,000	$80,000
1.1.2	Stoplogs Guides (4 Sets)	Kg	11,000	$15	$165,000
1.2	**Intake Structure**				**$655,300**
1.2.1	Trashrack & Guides	Kg	9,300	$15	$139,500
1.2.4	Intake Stoplogs & Guides	Kg	7,400	$17	$125,800
1.2.3	Roller Gate & Gate Guides	Kg	13,000	$20	$260,000
1.2.3	Gate Hoists	Ea	1	$30,000	$30,000
1.2.4	Hoist for Stoplog & Gate	kg	5,000	$20	$100,000
2	**Powerhouse M&E**				**$4,782,400**
2.1	***PH Water to Wire Equipment***				***$3,900,000***
2.1.1	Supply Water to Wire (W2W) Equipment	LS	1	$2,800,000	$2,800,000
2.1.2	Delivery W2W Equipment to Site	LS	1	$200,000	$200,000
2.1.3	Installation W2W Equipment	LS	1	$900,000	$900,000
2.2	**Auxiliary Mechanical System**				**$425,000**
2.2.1	Drainage & Dewatering Systems	LS	1	$50,000	$50,000
2.2.2	Fire Protection System	LS	1	$25,000	$25,000
2.2.3	Domestic & Service Water Systems	LS	1	$50,000	$50,000
2.2.4	HVAC Station System	LS	1	$95,000	$95,000
2.2.5	Piezometer Piping	LS	1	$15,000	$15,000
2.2.6	Compressed Air System	LS	1	$40,000	$40,000
2.2.7	P/H Crane (15 Tonne)	LS	1	$150,000	$150,000
2.3	**Auxiliary Electrical System**				**$175,000**
2.3.1	LV Power & Control Cables	L.S.	1	$35,000	$30,000
2.3.2	PH Grounding System	L.S.	1	$35,000	$30,000
2.3.3	Emergency Diesel Generator Set	L.S.	1	$40,000	$35,000
2.3.4	Building Services - Including Lighting System & Wiring	L.S.	1	$50,000	$50,000
2.3.5	Fire Protection and Security System	L.S.	1	$35,000	$30,000
2.4	**Draft Tube Closure Gates**				**$282,400**
2.4.1	Draft Tube Gates	Kg	11,400	$20	$228,000
2.4.2	Draft Tube Guides	Kg	3,200	$17	$54,400
3	**Substation & Transmission Lines**				**$2,950,000**
3.1	**Substation (Electrical)**				**$1,000,000**
3.1.1	Step-Up Transformer (1.8 MVA, 34.5/4.16kV)	Ea	2	$200,000	$400,000
3.1.2	Transformer Protection	L.S.	1	$50,000	$50,000
3.1.3	34.5kV Metal-Clad, Outdoor Switchgear	L.S.	1	$200,000	$200,000

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Figure 6-4:
Site 8C-2 (2 x 1,500 kW = 3.0 MW - Run-of-River Project)
Cost Estimate

Item	Description	Unit	Estimated Quantity	Unit Price ($/Unit)	Amount ($)
3.1.4	SCADA	L.S.	1	$200,000	$200,000
3.1.5	Line Disconnect Switch	L.S.	1	$50,000	$50,000
3.1.6	Interconnection with Existing DG	L.S.	1	$50,000	$50,000
3.1.7	Revenue Metering	L.S.	1	$50,000	$50,000
3.2	**Transmission Line (34.5 kV)**				**$1,950,000**
3.2.1	Supply & Install Transmission Line to PHS	km	13	$150,000	$1,950,000
	Sub-Total - Mechanical & Electrical Works				**$8,632,700**
Subtotal A - Civil Works					**$18,880,000**
Subtotal B - Mechanical & Electrical Works					**$8,632,700**
Subtotal C - Construction Facilities, Indirect Cost & Northern Factor			30%	(of A+B)	**$8,253,800**
Subtotal Without Contingencies					**$35,766,500**
Contingencies					**$4,639,300**
Civil Works			20%		**$3,776,000**
Mechanical & Electrical Works			10%		**$863,300**
Total Estimated Construction Cost					**$40,405,800**
Environmental, Engineering, Administration and Site Inspection			7.5%		**$3,030,400**
Total Estimated Project Cost					**$43,436,200**
	Total Cost $/kW				***$14,500***

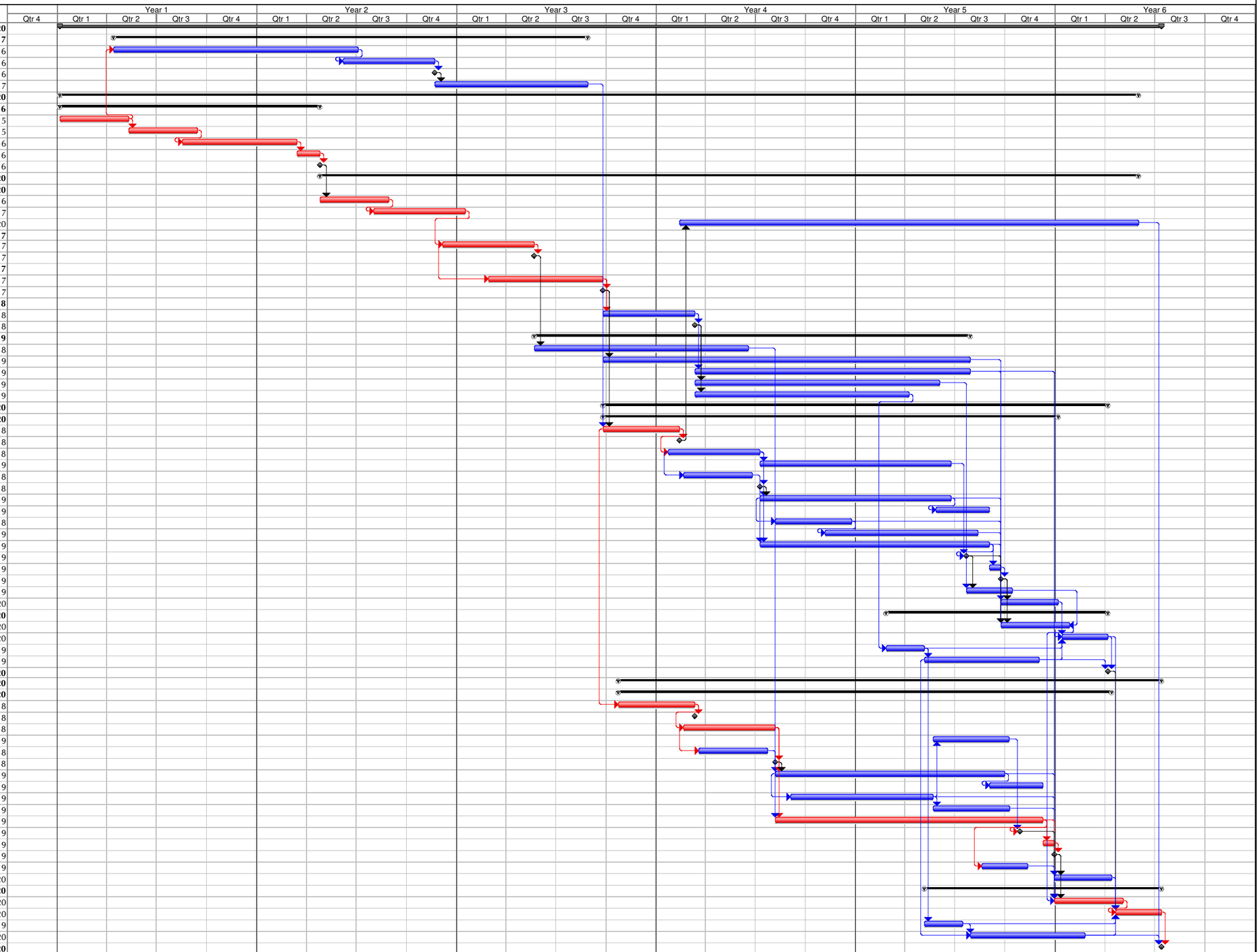
Exclusions:

- escalation beyond October 2012
- taxes
- land
- isolated grid and interconnection costs
- financing

Figure 6-5

Coastal Labrador Hydro - Proposed Project Schedule - Site 5B and Site 8C-2

ID	Task Name	Start	Finish
1	**SITE DEVELOPMENT (5B & 8C-2)**	**Jan 6 '15**	**Jul 13 '20**
2	**ENVIRONMENTAL PROCESS**	**Apr 14 '15**	**Aug 28 '17**
3	Phase 1- Field Studies, Consultation & Impact Assessmen	Apr 14 '15	Jul 4 '16
4	Phase 2-EA Report Preparation	Jun 7 '16	Nov 21 '16
5	Notice of Completion Published	Nov 21 '16	Nov 21 '16
6	Permits & Approvals (Provincial and Federal)	Nov 22 '16	Aug 28 '17
7	**ENGINEERING, DESIGN AND PROCUREMENT**	**Jan 6 '15**	**Jun 1 '20**
8	**FEL - 3 - Site Investigations and Detailed Engineering**	**Jan 6 '15**	**Apr 25 '16**
9	Preliminary Engineering	Jan 6 '15	May 11 '15
10	Site Investigations and Surveys	May 12 '15	Sep 14 '15
11	Detail Engineering	Aug 18 '15	Mar 14 '16
12	Nalcor Review	Mar 15 '16	Apr 25 '16
13	Nalcor Approval to Proceed	Apr 25 '16	Apr 25 '16
14	**FEL - 4 - Implementation Phase**	**Apr 26 '16**	**Jun 1 '20**
15	**Engineering**	**Apr 26 '16**	**Jun 1 '20**
16	Tender Documents & Drawings	Apr 26 '16	Aug 29 '16
17	Final Design	Aug 2 '16	Jan 16 '17
18	Site Inspection & Construction Drawings	Feb 13 '18	Jun 1 '20
19	**Wire-to-Contract (WWES)**	**Dec 6 '16**	**May 22 '17**
20	Bid Period	Dec 6 '16	May 22 '17
21	Contract Award	May 22 '17	May 22 '17
22	**General Contract (inc. Gates, Stoplogs)**	**Feb 28 '17**	**Sep 25 '17**
23	Bid Period	Feb 28 '17	Sep 25 '17
24	Contract Award	Sep 25 '17	Sep 25 '17
25	**Balance of Plant M&E**	**Sep 26 '17**	**Mar 12 '18**
26	Bid Period	Sep 26 '17	Mar 12 '18
27	Contract Award	Mar 12 '18	Mar 12 '18
28	**Design, Manufacture & Delivery (5B & 8C-2)**	**May 23 '17**	**Jul 29 '19**
29	Major Embedded Parts	May 23 '17	Jun 18 '18
30	Water-to-Wire Equipment	Sep 26 '17	Jul 29 '19
31	BOP Mechanical/Electrical Equipment	Mar 13 '18	Jul 29 '19
32	Gates Stoplogs, Hoisting Structures	Mar 13 '18	Jun 3 '19
33	Substation Equipment & Poles	Mar 13 '18	Apr 8 '19
34	**CONSTRUCTION & INSTALLATION (Site 5B)**	**Sep 26 '17**	**Apr 6 '20**
35	**Civil Works**	**Sep 26 '17**	**Jan 6 '20**
36	Mobilization & Site Facilities	Sep 26 '17	Feb 12 '18
37	Commence Construction	Feb 12 '18	Feb 12 '18
38	Access Road	Jan 23 '18	Jul 9 '18
39	Reservoir Clearing	Jul 10 '18	Jun 24 '19
40	Cofferdams & Dewatering	Feb 20 '18	Jun 25 '18
41	River Diversion - in Use	Jul 9 '18	Jul 9 '18
42	Embankment Dam & Diversion Facilities	Jul 10 '18	Jun 24 '19
43	Fish Ladder	May 28 '19	Sep 2 '19
44	Spillway	Aug 7 '18	Dec 24 '18
45	Intake & Penstock	Nov 6 '18	Aug 12 '19
46	Powerhouse & Substation	Jul 10 '18	Sep 2 '19
47	Start Reservoir Impounding	Jul 23 '19	Jul 23 '19
48	PH Crane Installed	Sep 3 '19	Sep 23 '19
49	Powerhouse Enclosed	Sep 23 '19	Sep 23 '19
50	Install Intake & DT Gates & Stoplogs	Jul 23 '19	Oct 14 '19
51	Install E&M Equipment & Services	Sep 24 '19	Jan 6 '20
52	**W2W Equipment & Swyd & Transmission**	**Feb 26 '19**	**Apr 6 '20**
53	W2W Erection	Sep 24 '19	Jan 27 '20
54	Testing & Commissioning	Jan 14 '20	Apr 6 '20
55	Substation (Electrical)	Feb 26 '19	May 6 '19
56	Transmission Line (34.5 kV)	May 7 '19	Dec 2 '19
57	**In-Service**	**Apr 6 '20**	**Apr 6 '20**
58	**CONSTRUCTION & INSTALLATION (Site 8C-2)**	**Oct 24 '17**	**Jul 13 '20**
59	**Civil Works**	**Oct 24 '17**	**Apr 13 '20**
60	Mobilization & Site Facilities	Oct 24 '17	Mar 12 '18
61	Commence Construction	Mar 12 '18	Mar 12 '18
62	Access Road	Feb 20 '18	Aug 6 '18
63	Reservoir Clearing	May 23 '19	Oct 8 '19
64	Cofferdams & Dewatering	Mar 20 '18	Jul 23 '18
65	River Diversion - in Use	Aug 6 '18	Aug 6 '18
66	Embankment Dam & Diversion Facilities	Aug 7 '18	Sep 30 '19
67	Fish Ladder	Sep 3 '19	Dec 9 '19
68	Spillway	Sep 4 '18	May 22 '19
69	Intake & Penstock	May 23 '19	Oct 9 '19
70	Powerhouse & Substation	Aug 7 '18	Dec 9 '19
71	Start Reservoir Impounding	Oct 29 '19	Oct 29 '19
72	PH Crane Installed	Dec 10 '19	Dec 30 '19
73	Powerhouse Enclosed	Dec 30 '19	Dec 30 '19
74	Install Intake & DT Gates & Stoplogs	Aug 20 '19	Nov 11 '19
75	Install E&M Equipment & Services	Dec 31 '19	Apr 13 '20
76	**W2W Equipment & Swyd & Transmission**	**May 7 '19**	**Jul 13 '20**
77	W2W Erection	Dec 31 '19	May 4 '20
78	Testing & Commissioning	Apr 21 '20	Jul 13 '20
79	Substation (Electrical)	May 7 '19	Jul 15 '19
80	Transmission Line (34.5 kV)	Jul 30 '19	Feb 24 '20
81	**In-Service**	**Jul 13 '20**	**Jul 13 '20**



Project: Site 5B and 8C-2
Date: Mar 21 '13

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Critical — Task — Split — Milestone ◆ — Summary

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