Newfoundland and Labrador Hydro

Phase 2: Project Definition Phase - Annex No. 1 - Potential Storage

For

Feasibility Study of Hydraulic Potential of Coastal Labrador

H340870-0000-00-124-0002
Rev. 2
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Phase 2: Project Definition Phase - Annex No. 1 - Potential Storage

REGISTERED PROFESSIONAL ENGINEER
ANTHONY CHISLETT
SIGNATURE
01-MAY-2018
DATE
NEWFOUNDLAND & LABRADOR

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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 No. 1 – 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.

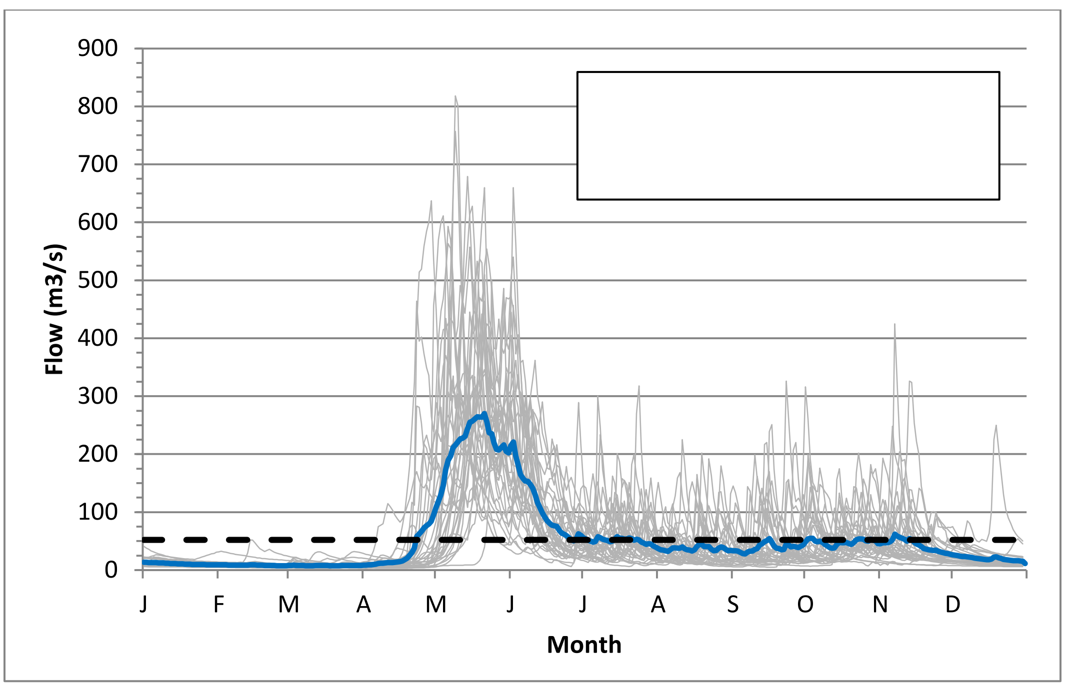

Figure 2-1: Alexis River Annual Hydrographs and Mean Annual Flow

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.

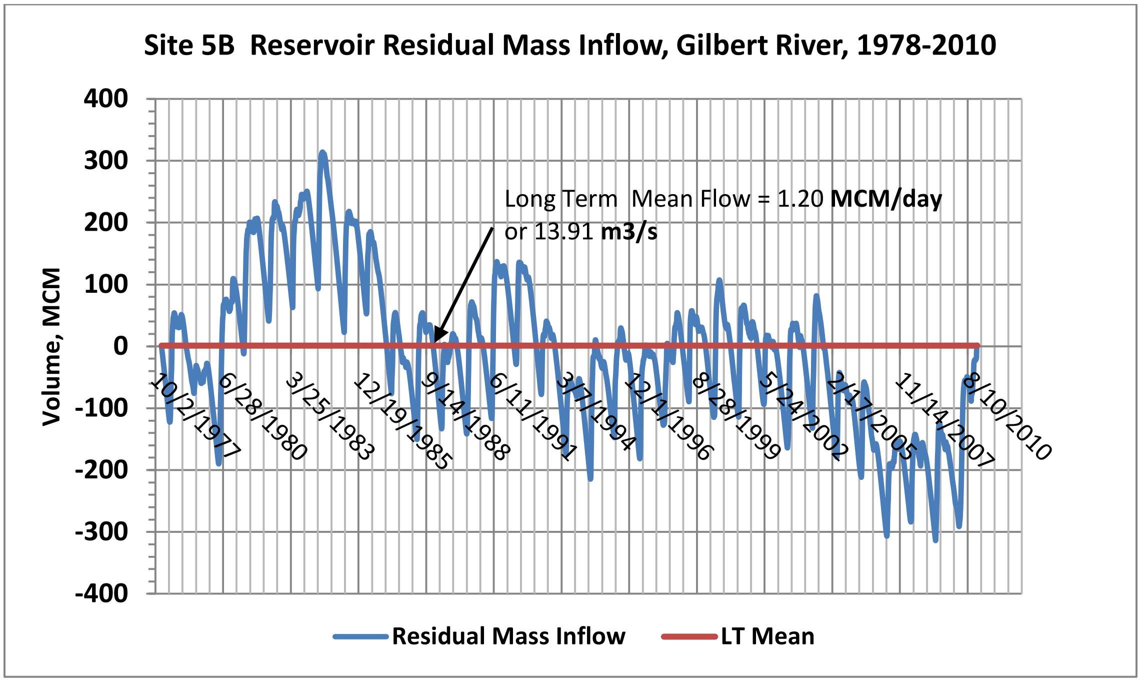

Figure 2-2: Residual Mass Curve, Site 5B

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 4-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 4-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.

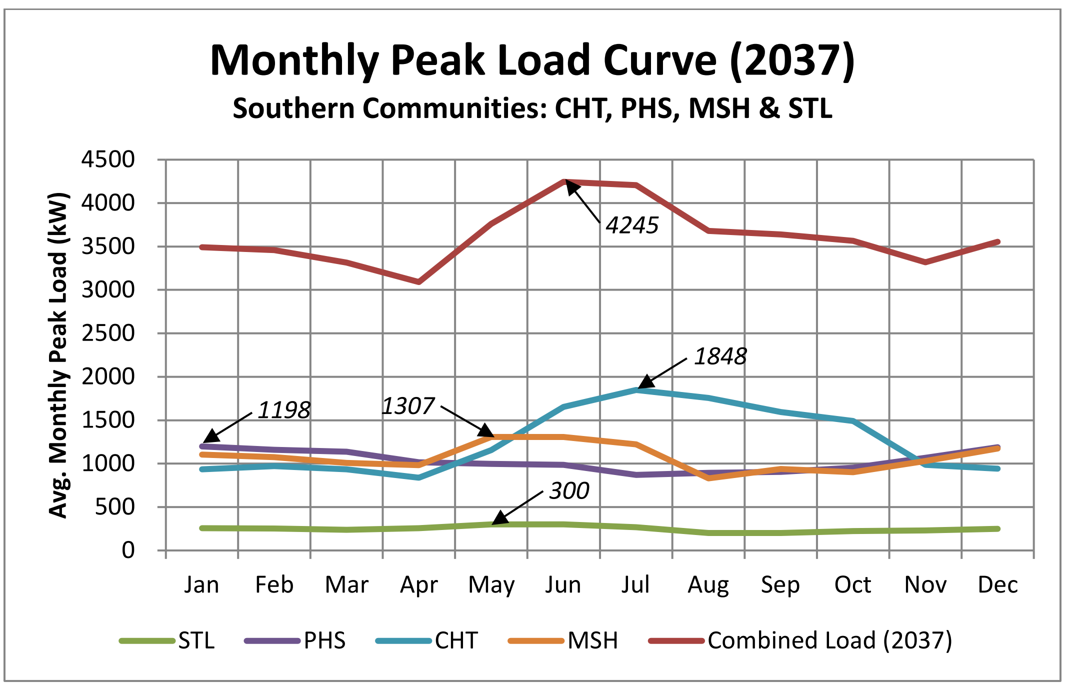

Figure 3-1: Projected Demand Curve for Communities of CHT, PHS, STL and MSH

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.

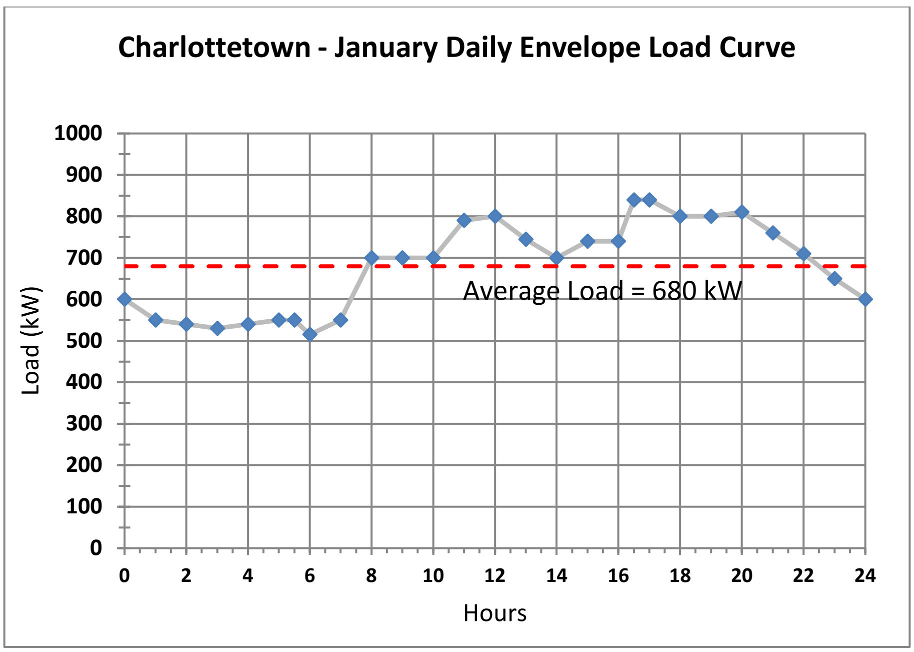

Figure 3-2: Envelope Daily Load Pattern at Charlottetown for January

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.

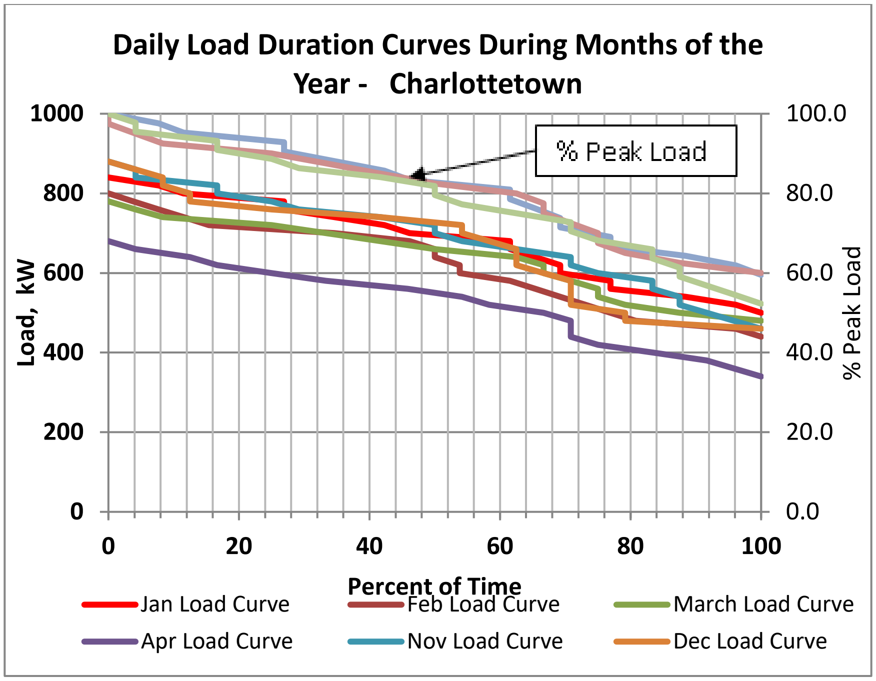

Figure 3-3: Load Duration Curves - Charlottetown

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	1	2	2	1
	(c/w bifurcation)	(c/w bifurcation)			(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 powerhouse 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.

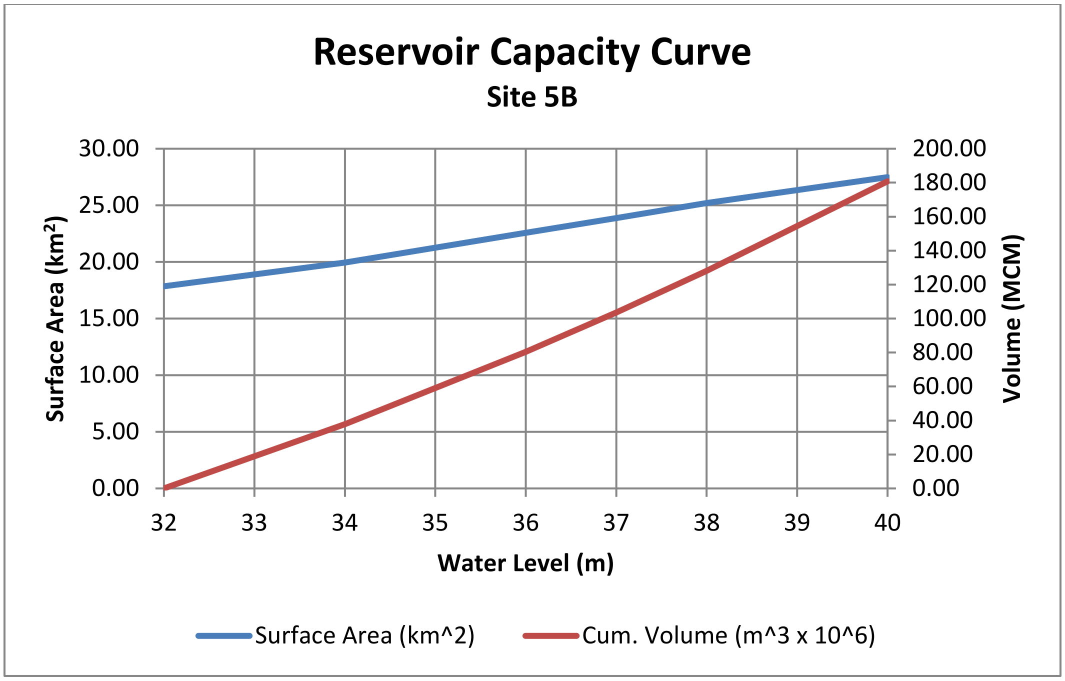

Figure 4-1: Site 5B Reservoir Capacity Curve

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.

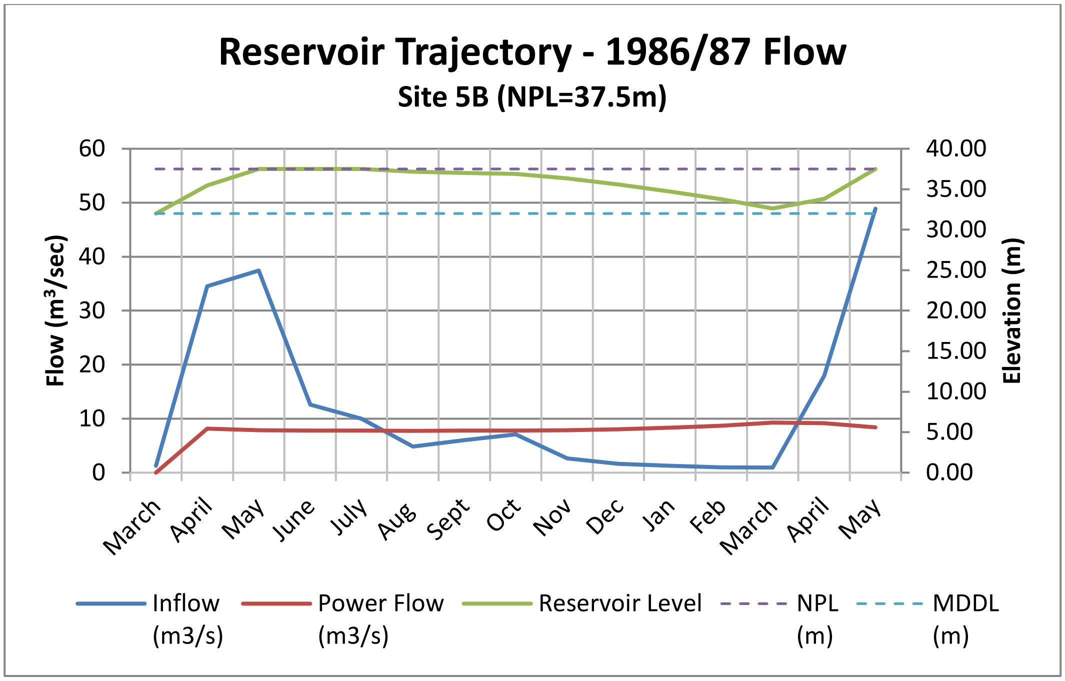

Figure 4-2: Site 5B Reservoir Trajectory in Critical Dry Year and Flow Hydrographs

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.

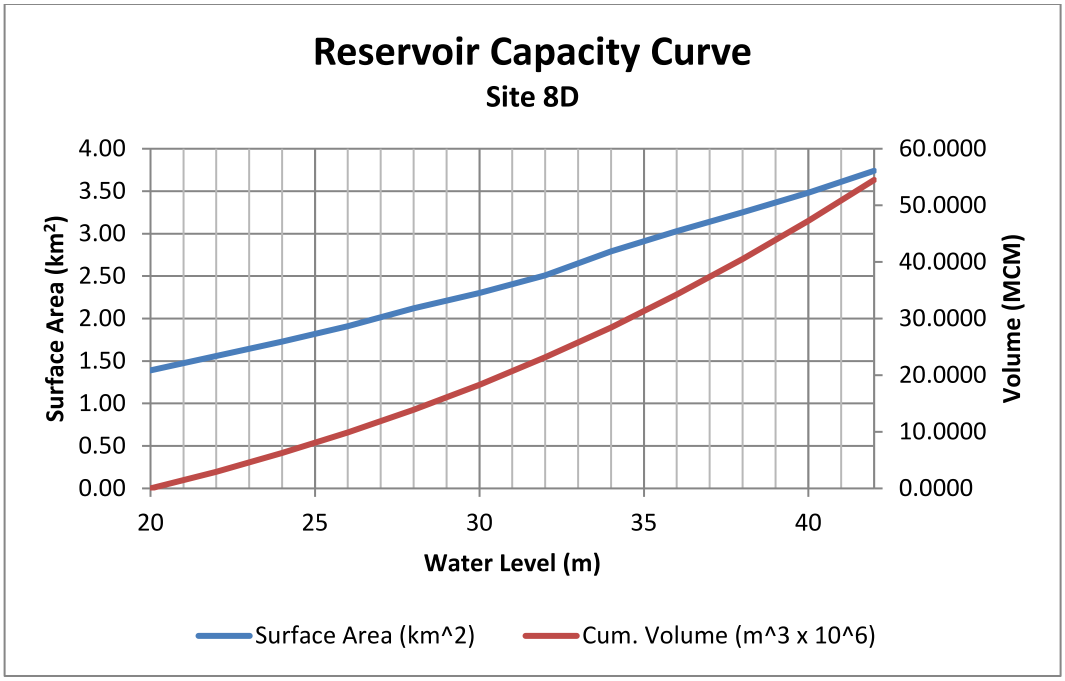

Figure 4-3: Site 8D Reservoir Capacity Curve

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.

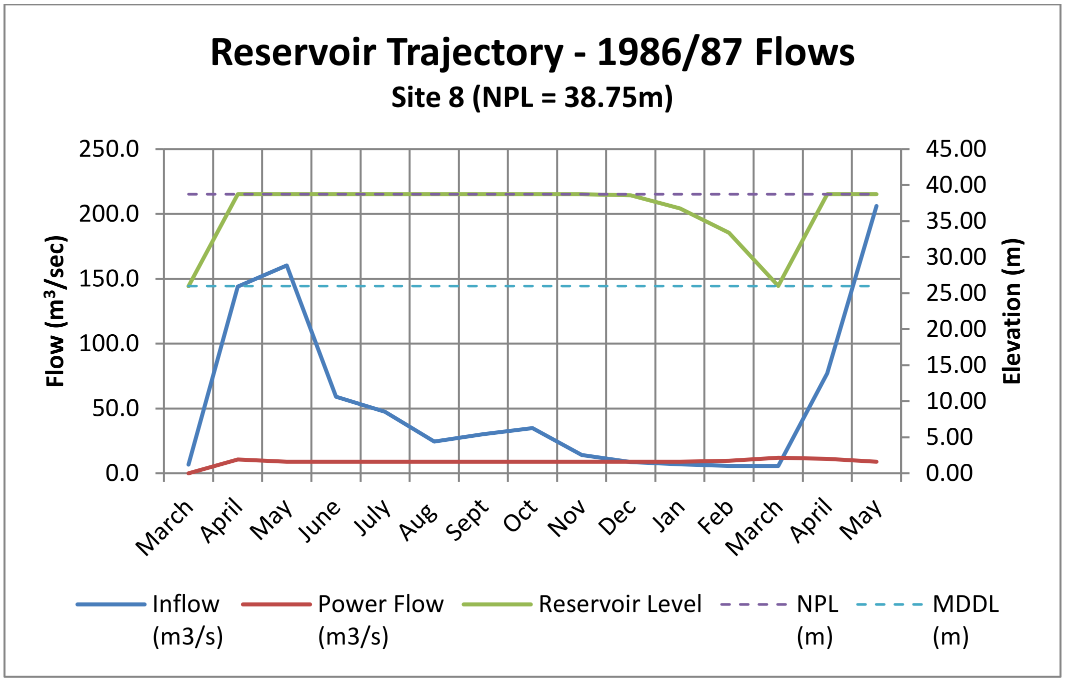

Figure 4-4: Site 8D Water Balance Variables and Reservoir Trajectory

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 40 m 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.

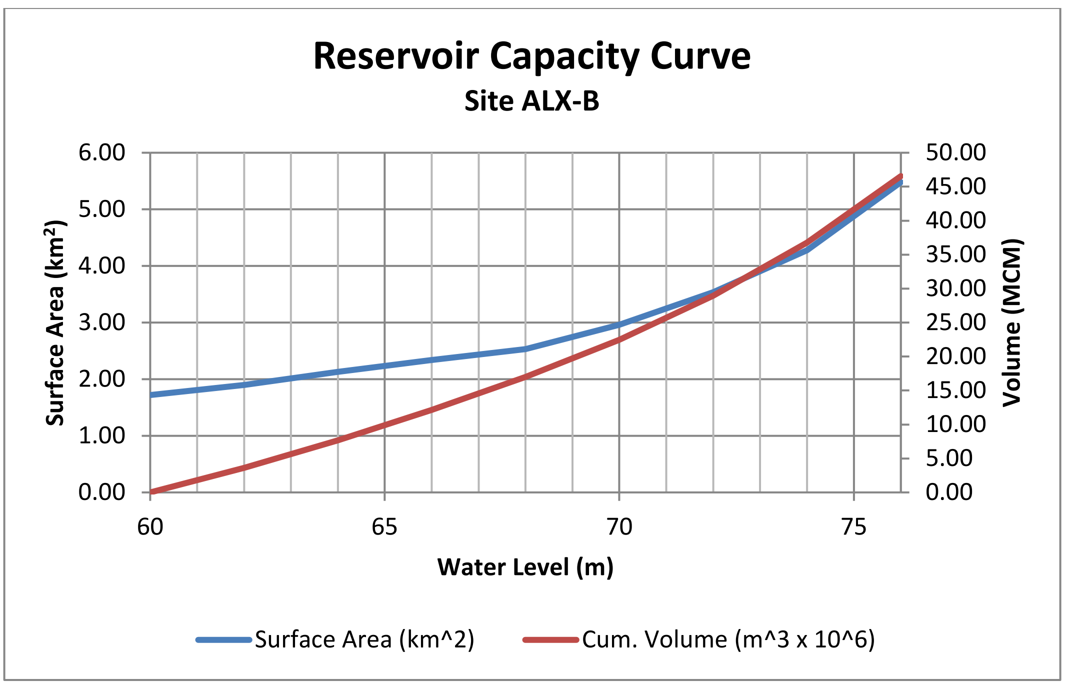

Figure 4-5: Site ALX-B Reservoir Capacity Curve

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.

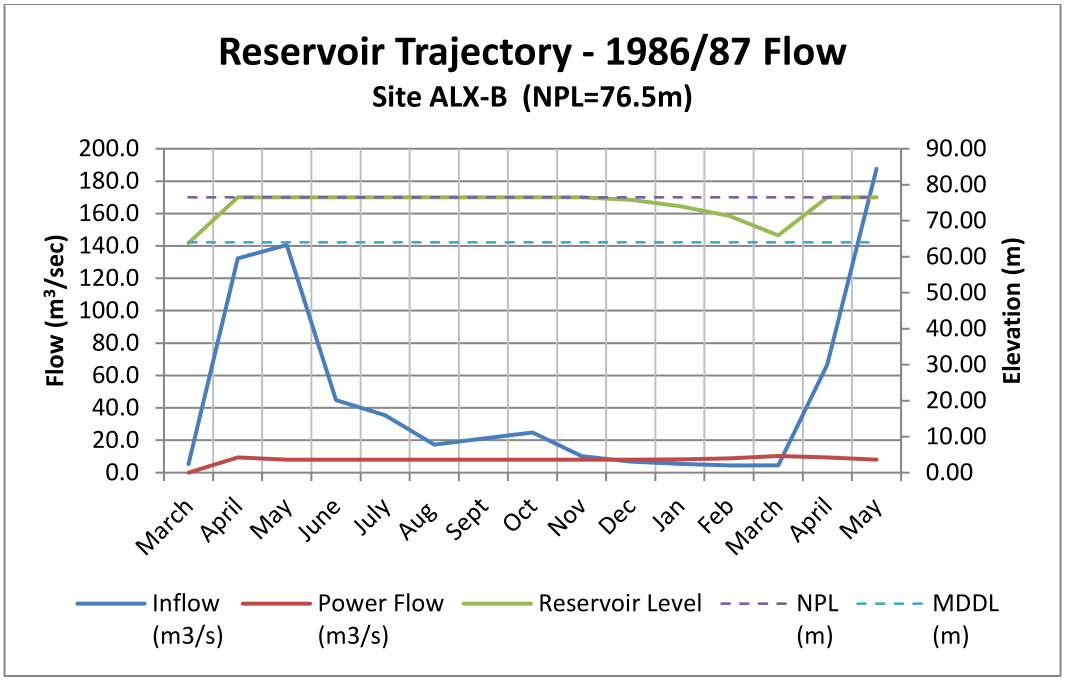

Figure 4-6: Site ALX-B Reservoir Trajectory

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 2 sites serving Isolated Grid serving all communities (5B+8C-2)	5B-2	CHT	Storage	2500	2300	2	31.4	9.11
	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 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 stoplogs 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 powerplant switching equipment will be located in the powerhouse.

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 powerplant 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 2791 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.

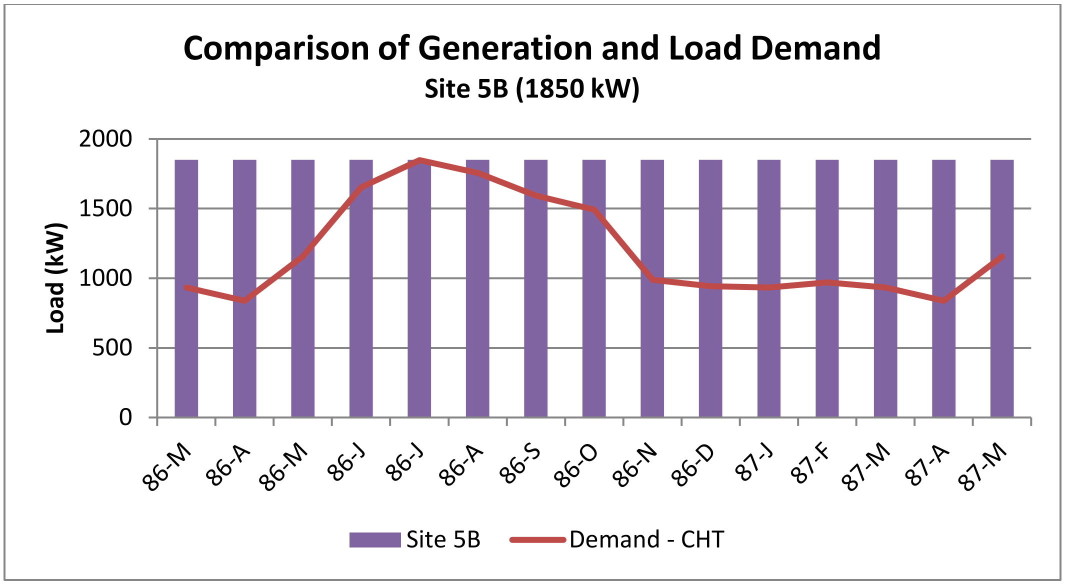

Figure 5-1: CHT Demand and Site 5B Generation in (1986/1987) Dry Year

5.1.2 *Site 8D*

For Generation Option #1 Site 8D provides 2800 kW 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.

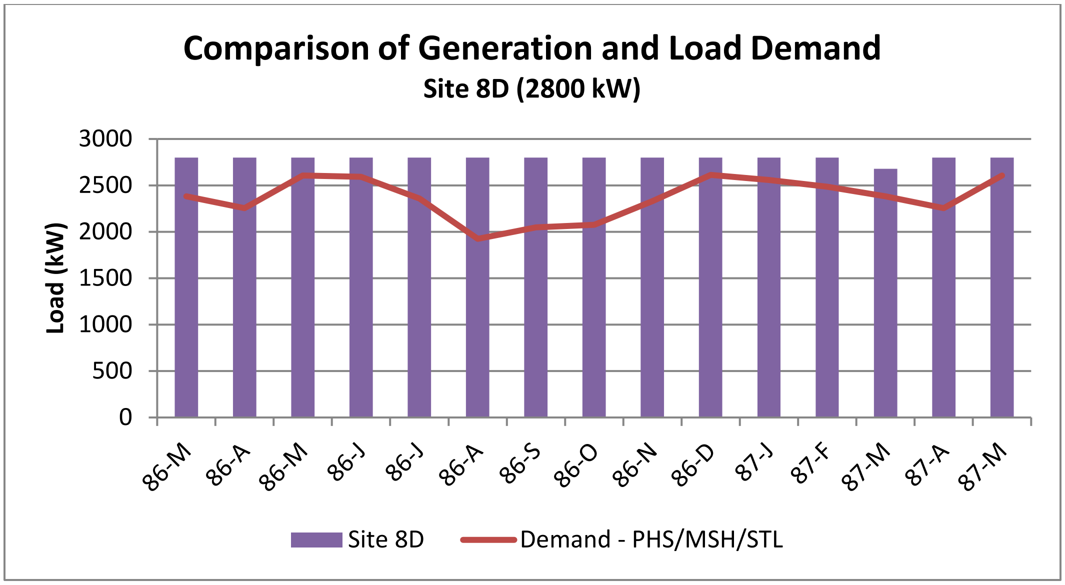

Figure 5-2: PHS/MSH/STL Demand and Site 8D Generation in (1986/1987) Dry Year

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.

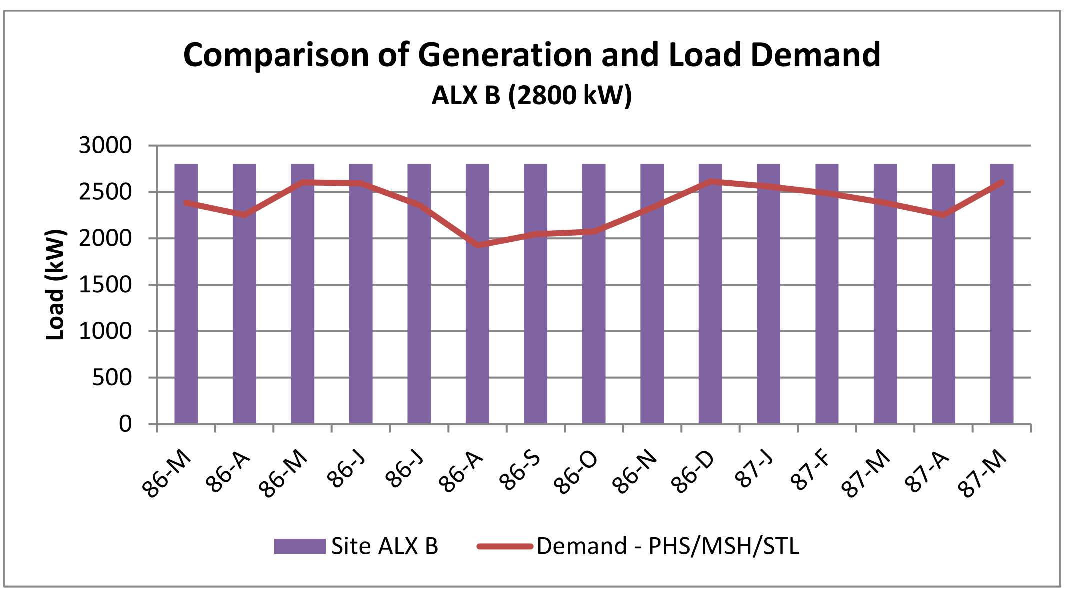

Figure 5-3: PHS/MSH/STL Demand and Site ALX-B Generation in (1986/1987) Dry Year

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. Although the combined generation from Site 5B-2 and Site 8C-2 would satisfy the forecasted energy requirements from all four communities during the critical dry period, it would not supply the forecasted peak power demand during these four months. The shortfall in demanded power would need to be supplied by additional generation (e.g., stand-by diesel); it should be noted that costs of such additional generation are not included in the cost estimates.

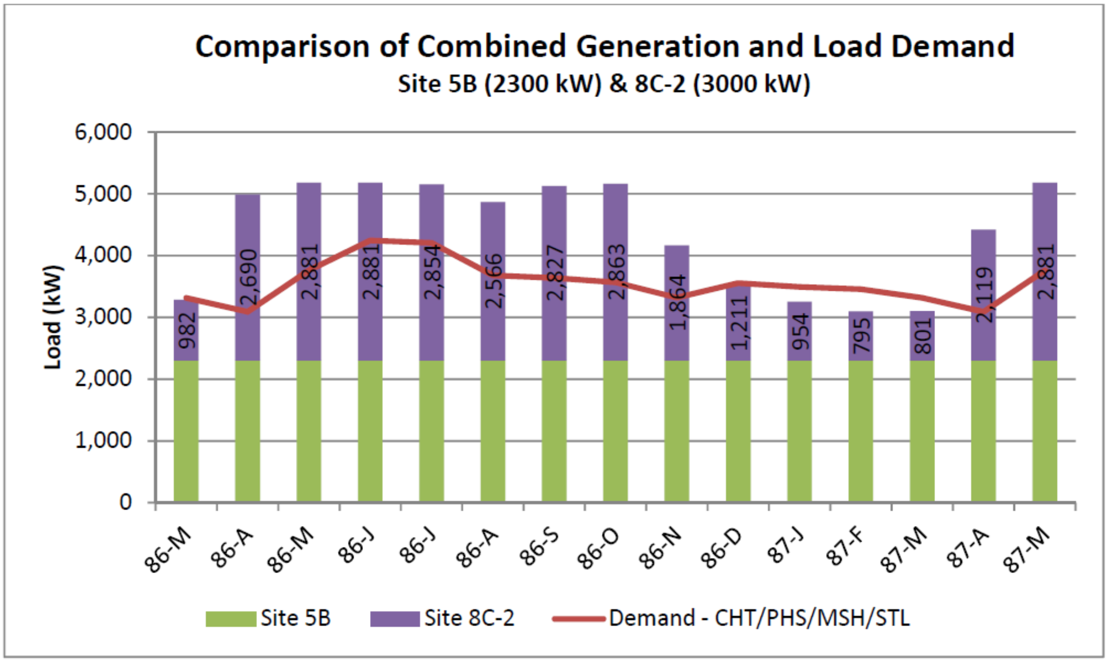

Figure 5-4: CHT/PHS/MSH/STL Demand and Site 5B and Site 8C-2 Generation in (1986/1987) Dry Year

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 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.

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

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. Costs are in 2012 dollars and do not include the environmental and mitigation costs as well as the cost of obtaining approvals. The environmental costs would be considerable and raise the total cost as well as the levelized cost of demanded energy.

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	F/cast Community Peak Load (2037)	Installed Capacity	Plant Firm Capacity @ 97%	Annual Firm Energy supplied at 97%	Forecast Average Annual Energy Demand f/	Capacity Factor	Cost d/	Cost/kW	O & M Cost	Cost + IDC	Levelized Ann. Cost (50 yr, 7%)	2012 Cost of Forecast Demand Energy c/	2012 Cost of supplied Energy c/
				(kW)	(kW)	(kW)	(MWh)	(MWh)	(%)	($ Millions)	($/kW)	($ Millions/yr)	($ Millions)	($ Millions)	($/kWh)	($/kWh)
5B-1 a/	Charlottetown	Option # 1	Storage	1848	2,100	1,850	16,206	6,164	33.5	43.7	20,800	0.33	48.10	3.82	0.619	0.235
8D	PHS/MSH/STL	Option # 1	Storage	2791	3,500	2,800	24,528	12,438	40.6	148.4	42,400	0.33	162.31	12.09	0.972	0.493
ALX-B	PHS/MSH/STL	Option # 1	Storage	2791	3,500	2,800	24,528	12,438	40.6	96.0	27,400	0.33	107.81	8.14	0.655	0.332
5B-1 + 8D	CHT & PHS/MSH/STL	Option # 1	Storage	4637	5,600	4,650	40,734	18,602	37.9	192.1 e/	34,300	0.46	201.67	15.07	0.810	0.370
5B-1 + ALX-B	CHT & PHS/MSH/STL	Option # 1	Storage	4637	5,600	4,650	40,734	18,602	37.9	139.7 e/	24,900	0.46	146.92	11.11	0.597	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	10,250	46.8	45.7	18,300	0.33	50.19	3.97	0.387	0.197
5B-2 + 8C-2	CHT & PHS/MSH/STL	Option # 2	Storage+RoR	4637	5,500	3,095	27,112	18,602	38.6	89.0 e/	16,200	0.46	98.49	7.60	0.408	0.280

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
f/ Forecast energy demand based on 50-year continued Diesel Forecast supplied by Nalcor, 2013

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. Costs are in 2012 dollars and do not include the environmental and mitigation costs as well as the cost of obtaining approvals. The environmental costs would be considerable and raise the total cost as well as the levelized cost of demanded energy. 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 $0.810/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 $0.597/kWh. On the supply side, the levelized cost of energy is $0.273/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; when estimated for the critical dry period, the combined generation from Site 5B-2 and Site 8C-2 would satisfy the forecasted energy requirements from all four communities but would not supply the forecasted peak power demand during four months. The shortfall in demanded power would need to be supplied by additional generation (e.g., stand-by diesel); it should be noted that costs of such additional generation are not included in the cost estimates.

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 $0.408/kWh and $0.280/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. In the case of Site 5B, environmental assessment planning would need to consider the presence of the Gilbert Bay Golden Cod and Gilbert Bay Marine Protected Area (MPA). As requested by NLH, a brief commentary on the Gilbert Bay Golden Cod and MPA has been prepared by Hatch and Sikumiut Environmental Management Ltd. (SEM) for inclusion in this report, and is provided as Attachment 4.

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

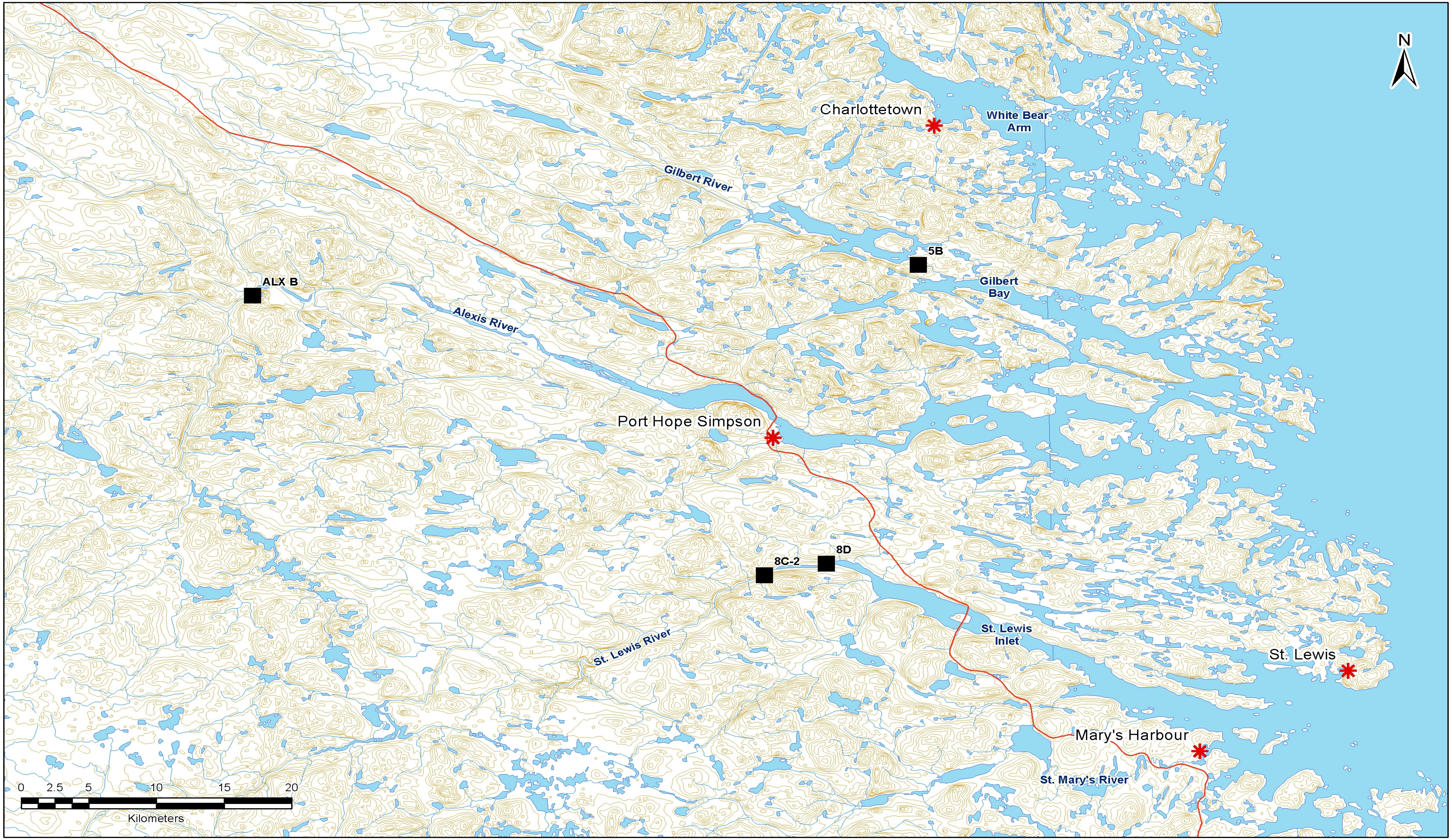

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Figure 1-1
Project Location Map
Coastal Labrador Hydro - Potential Storage
Newfoundland Labrador Hydro

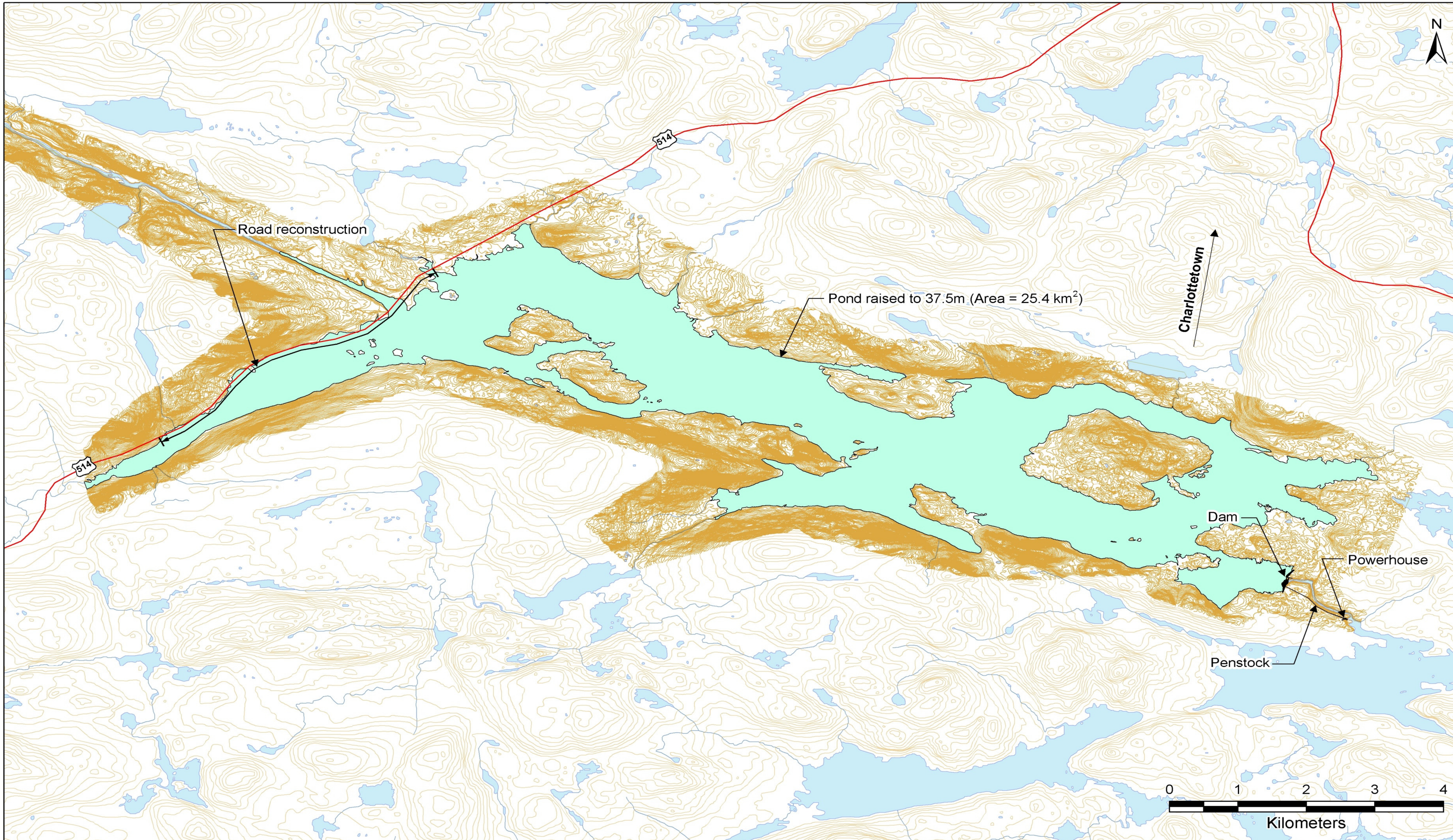

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Figure 1-2
Site 5B Headpond Inundation
Coastal Labrador Hydro - Potential Storage
Newfoundland Labrador Hydro

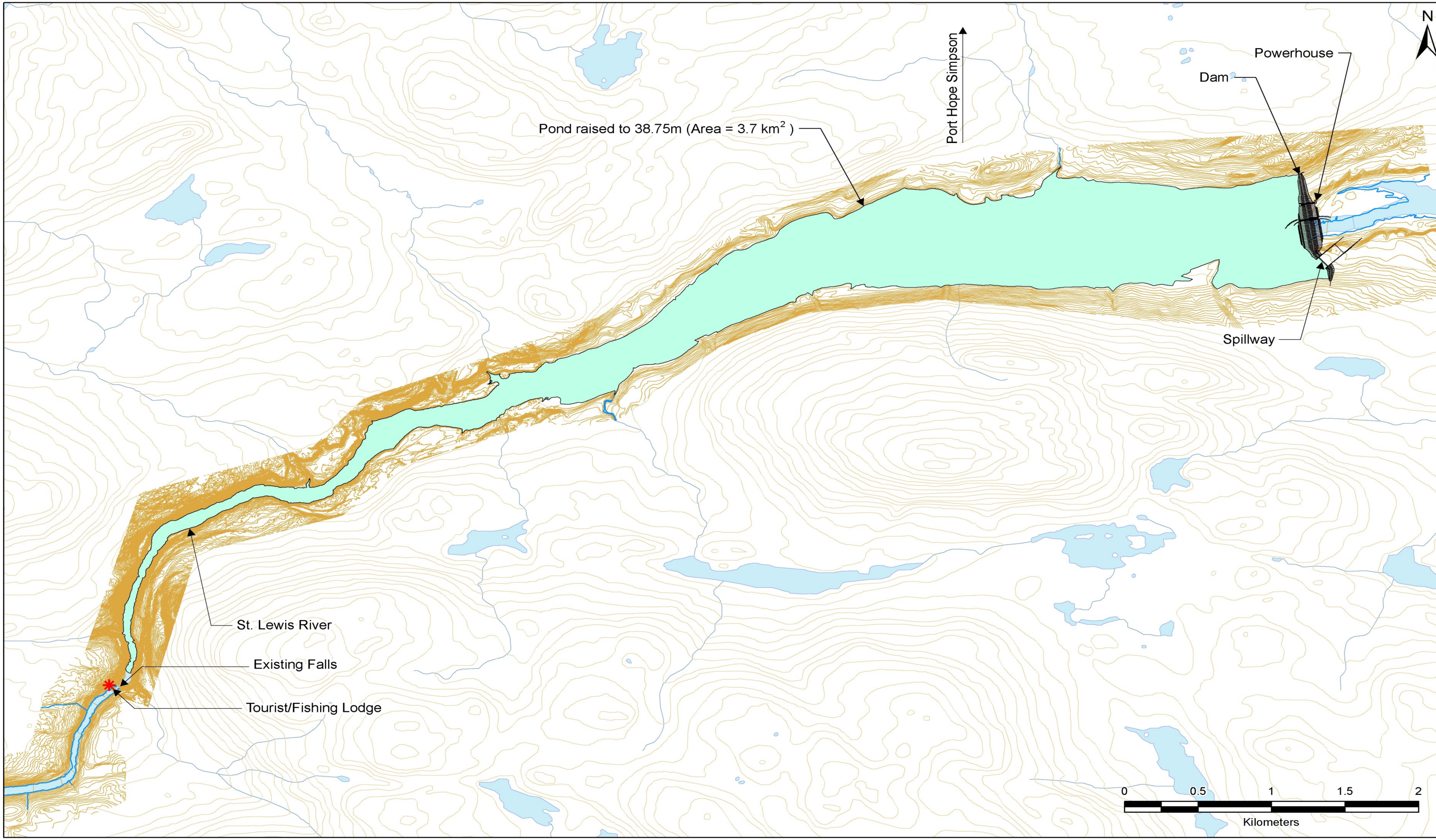

Figure 1-3
Site 8D Headpond Inundation
Coastal Labrador Hydro - Potential Storage
Newfoundland Labrador Hydro

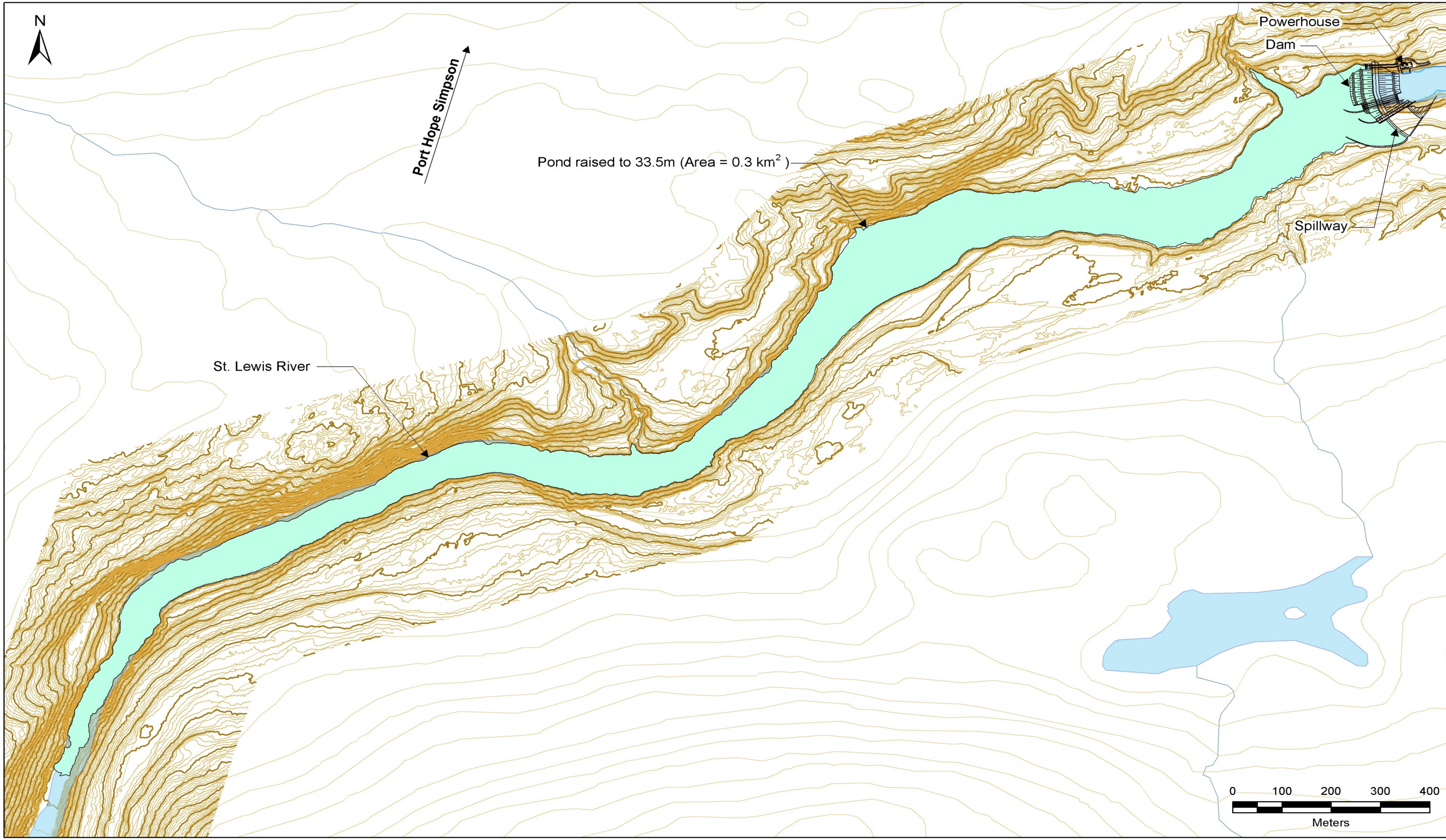

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Figure 1-4
Site 8C-2 Headpond Inundation
Coastal Labrador Hydro - Potential Storage
Newfoundland Labrador Hydro

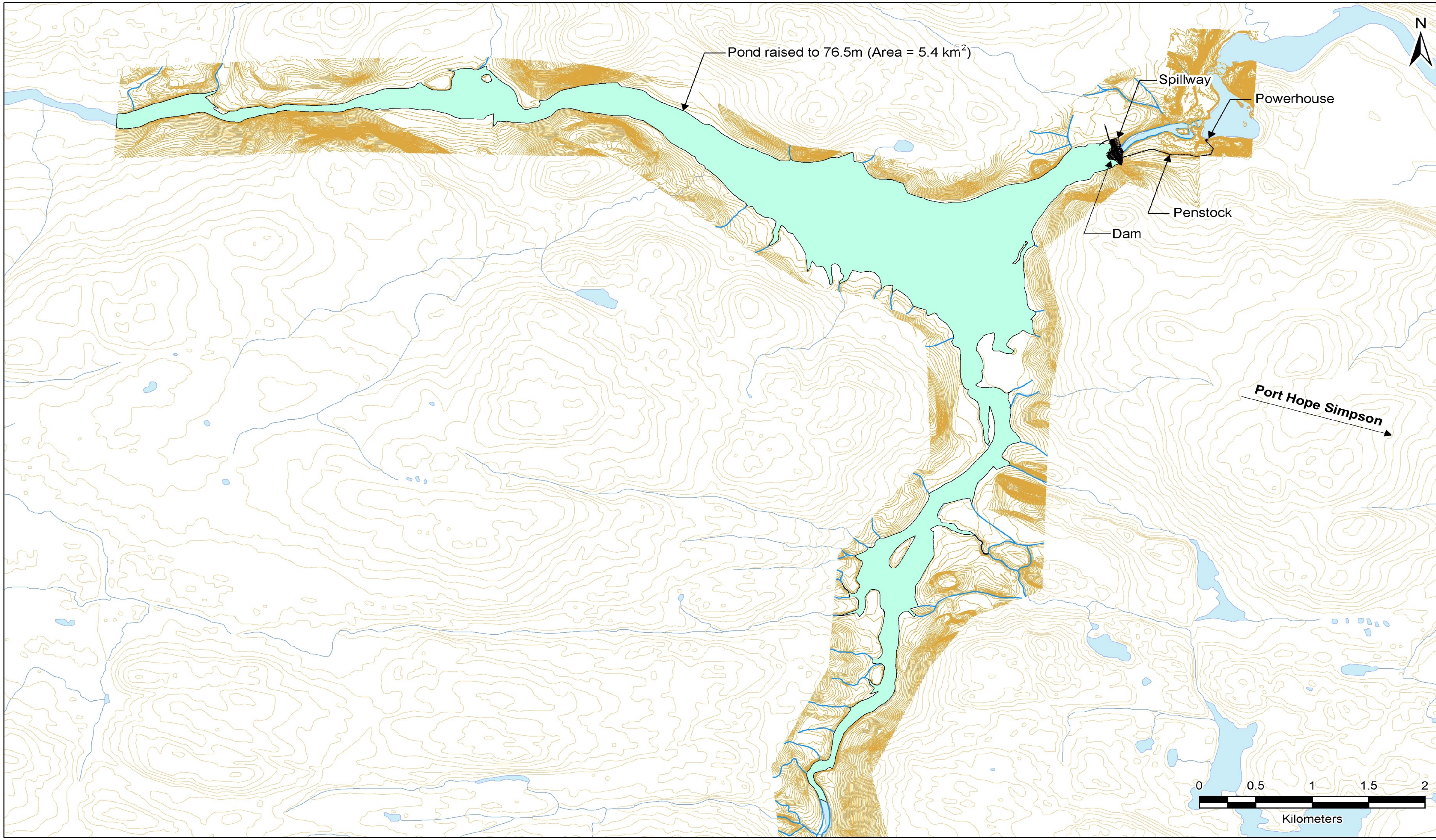


Figure 1-5
Site ALX B Headpond Inundation
Coastal Labrador Hydro - Potential Storage
Newfoundland Labrador Hydro

Attachment 2

Drawings

PLAN – GENERAL ARRANGEMENT SITE 5B

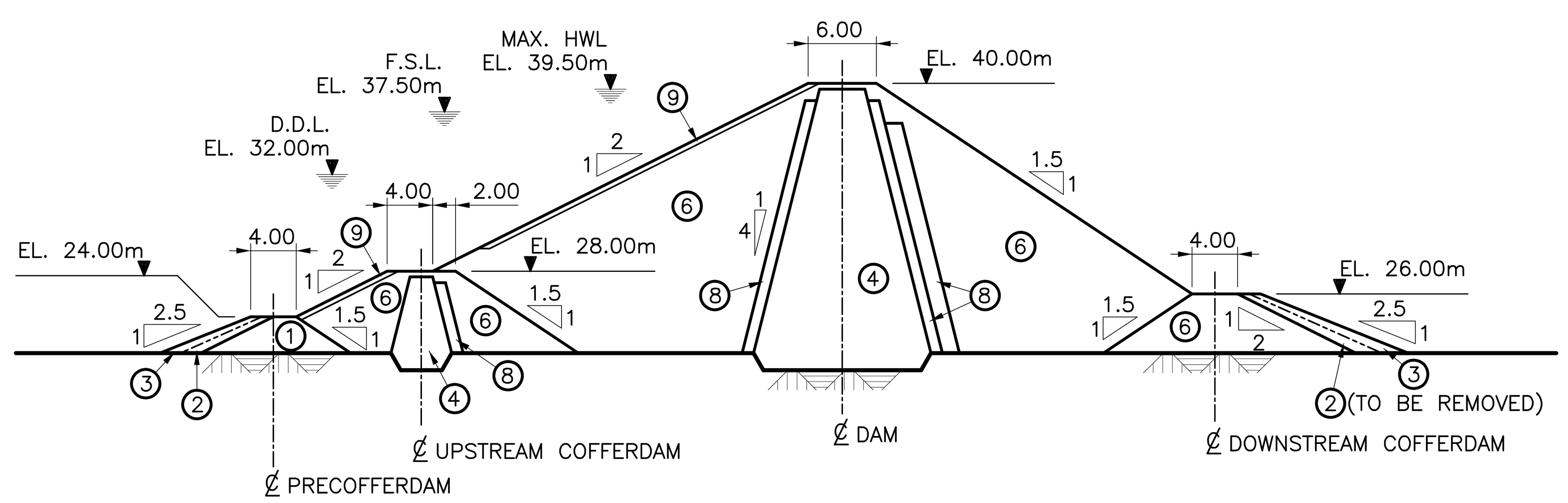
0m 50 100 150 200 250

SCALE: 1:2500

HATCH™ 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	SITE 5B – GENERAL ARRANGEMENT PLAN
SCALE 1:2500 (D-SHEET) HATCH Ltd. PROJECT NO. H340870	DRAWING NO. H340870-SITE 5B-001 SHEET 1 OF 4 REVISION A

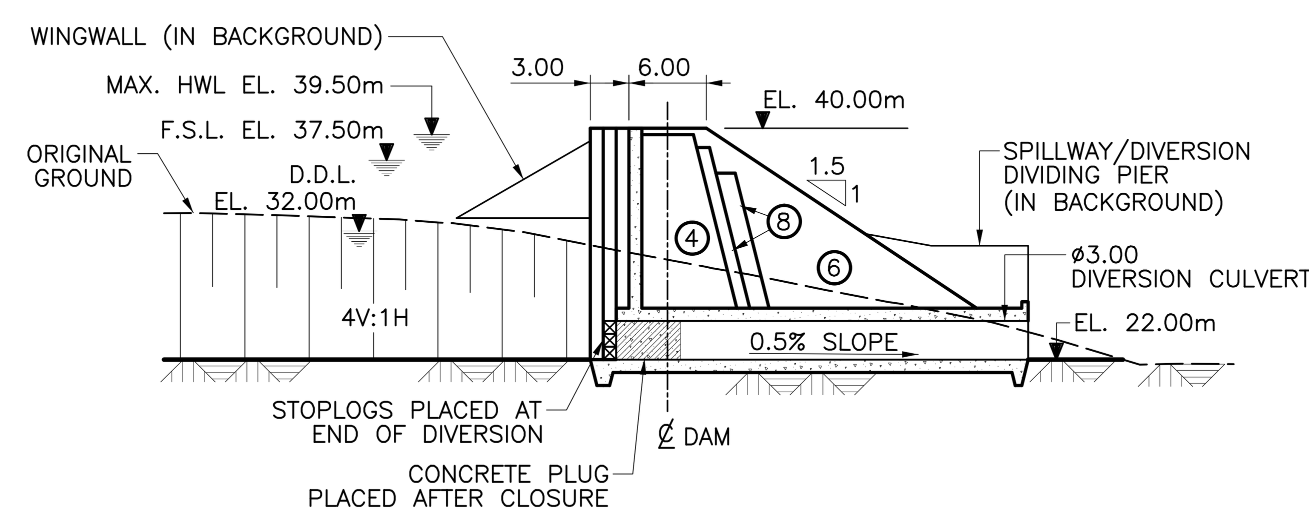
A DAM LONGITUDINAL PROFILE
002 001

SCALE: 1:500



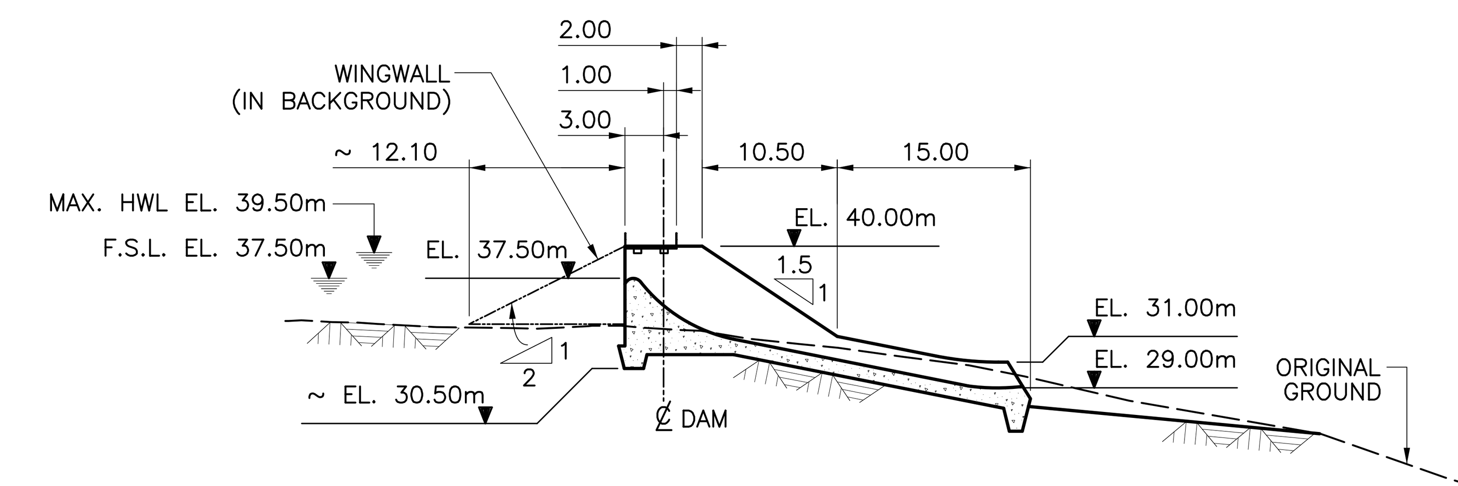
B SECTION – IMPERVIOUS CORE ALTERNATIVE

SCALE: 1:500



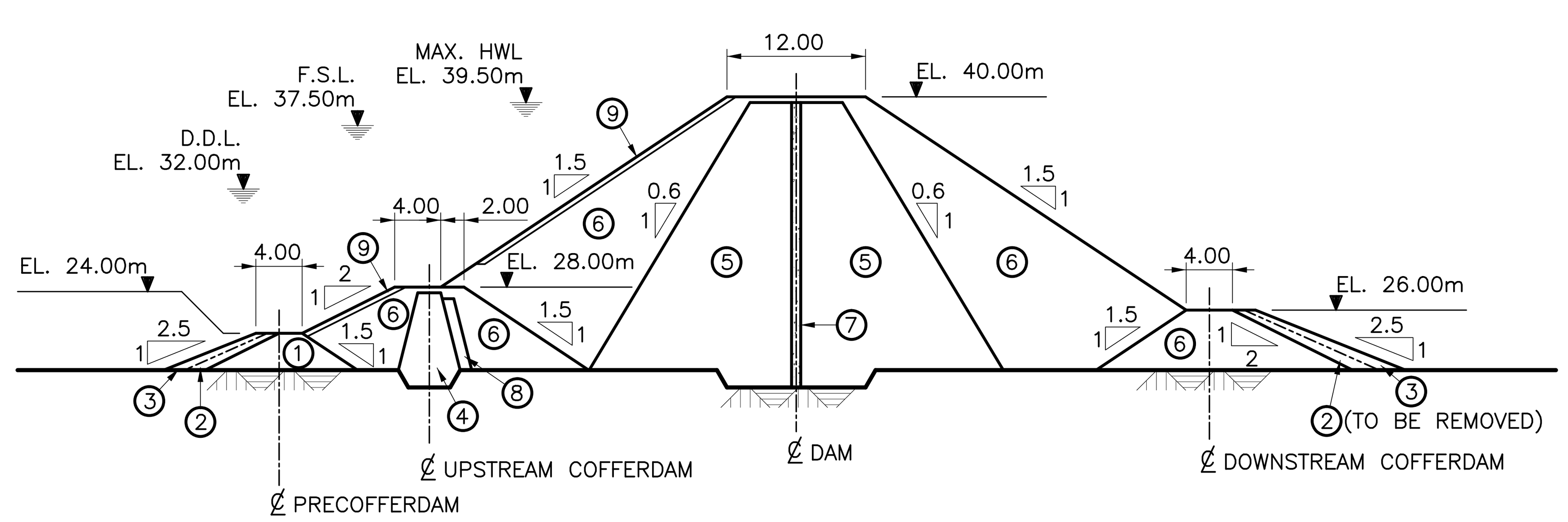
C SECTION – DIVERSION CULVERTS

SCALE: 1:500



D SECTION – SPILLWAY

SCALE: 1:500



B SECTION – SLURRY WALL ALTERNATIVE

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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COASTAL LABRADOR HYDRO
PHASE 2: POTENTIAL STORAGE

SITE 5B – HEADWORKS
PROFILE AND SECTIONS

DESIGN PREPARED	G. FRANK
DESIGN CHECKED	M. McFARLANE
DRAWING PREPARED	S. RUSSELL
DRAWING CHECKED	J. WAYE
PROJECT MANAGER	M. McFARLANE
SCALE	1:500 (D-SHEET)
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DRAWING NO.	H340870-SITE 5B-002
REVISION	A

SHEET 2 OF 4

M 003 001 PENSTOCK LONGITUDINAL SECTION

SCALE: 1:1500 H, 1:150V

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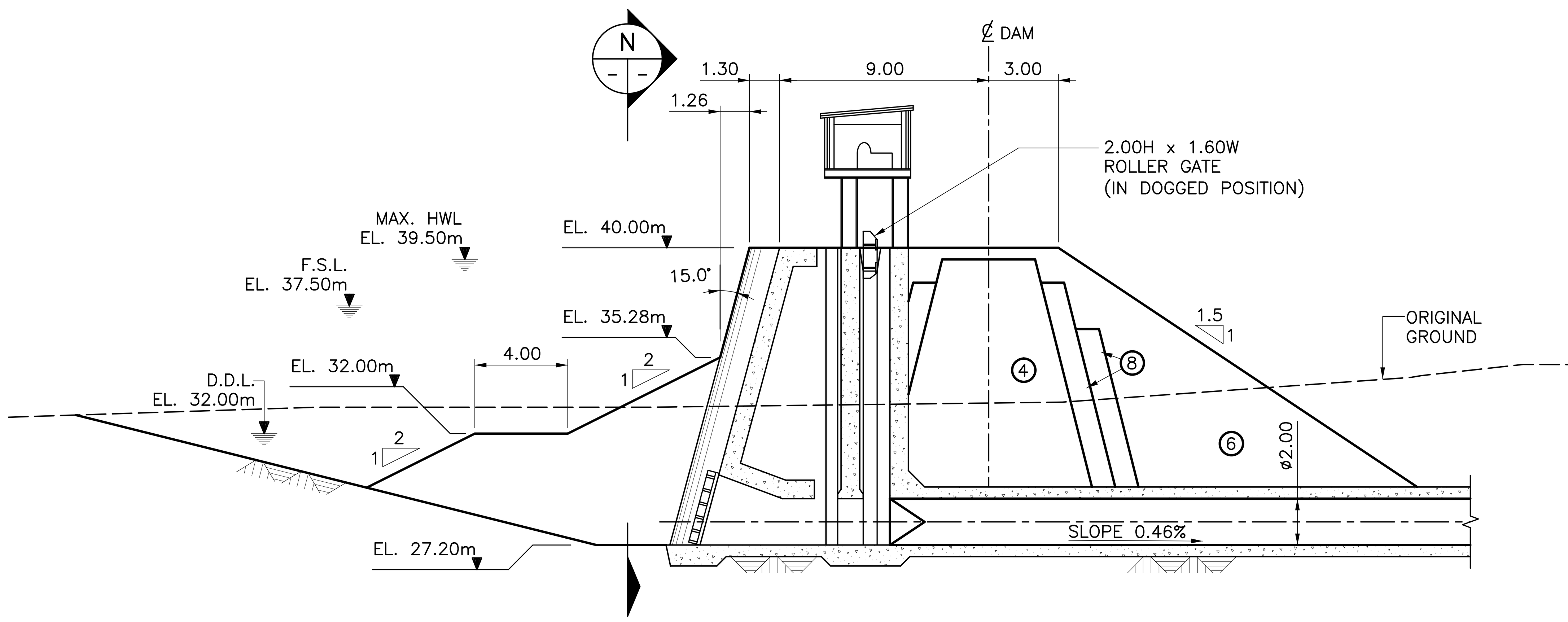
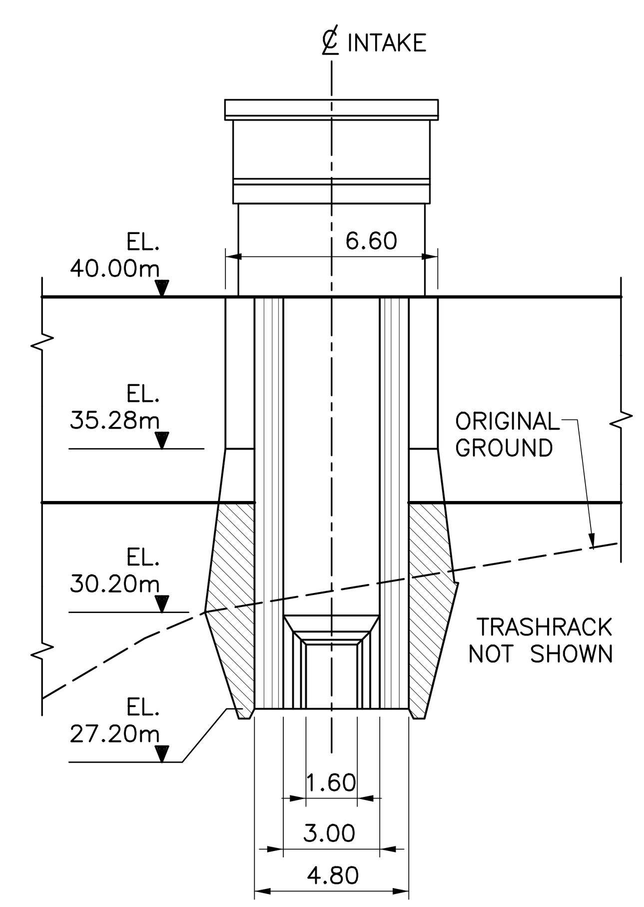
0m 3 6 9 12 15 — SCALE: 1:150



1 LONGITUDINAL SECTION (INTAKE END)

0m 4 8 12 16 20 — SCALE: 1:200



N INTAKE – FRONT ELEVATION

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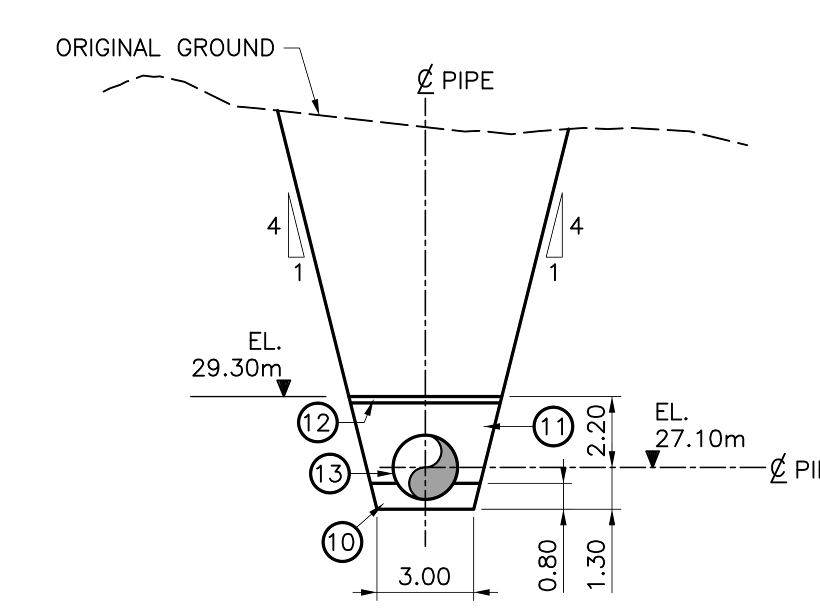
4	COMPACTED IMPERVIOUS FILL
6	COMPACTED ROCKFILL
8	FILTERS/TRANSITION FILL
10	FINE GRANULAR BEDDING (WELL COMPACTED)
11	GRAVEL BACKFILL (THERMAL INSULATION)
12	RIPRAP
13	ø2.00 PENSTOCK



P 003 001 SECTION

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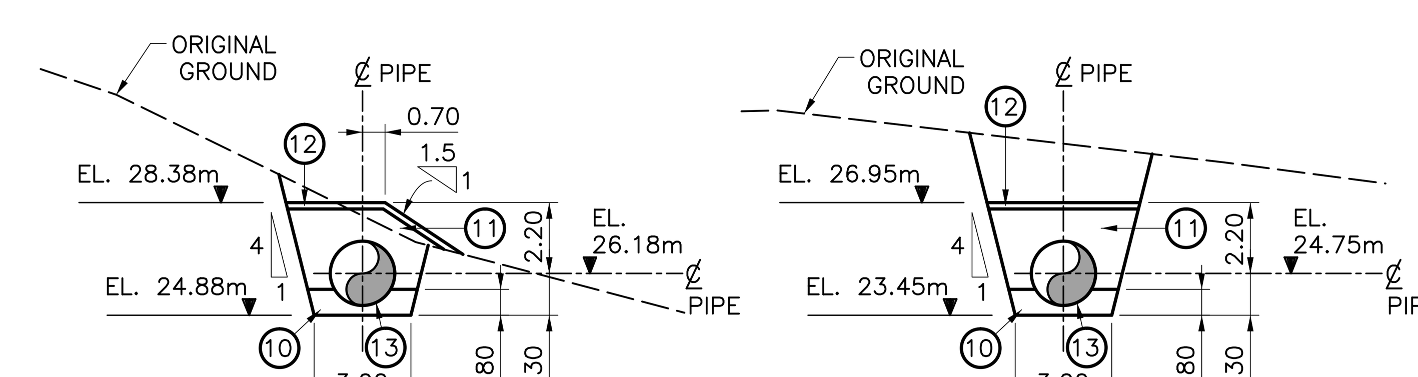


Q 003 001 SECTION

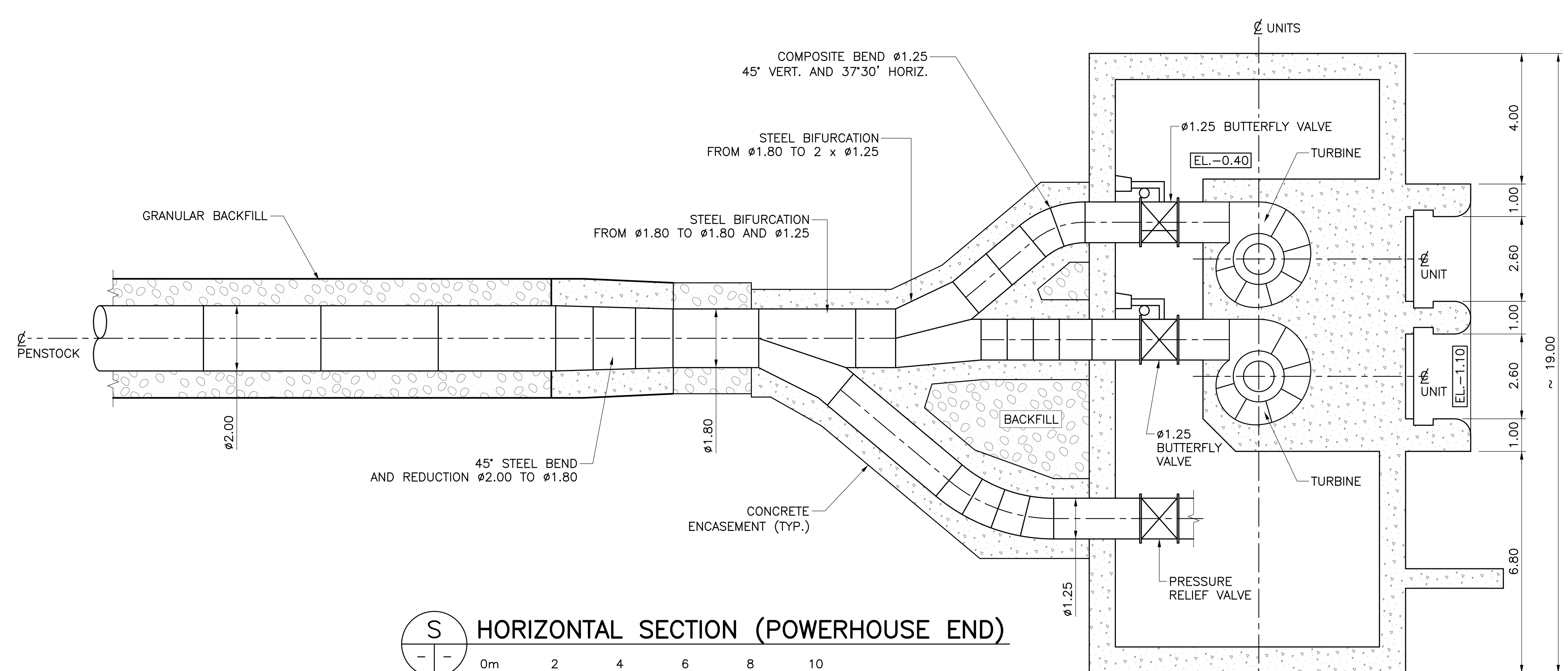
R 003 001 SECTION

0m 4 8 12 16 20 — SCALE: 1:200

HATCH™	NL HYDRO ST. JOHN'S, NL, CANADA
HATCH Ltd.	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	SITE 5B – PROFILE AND SECTIONS
SCALE AS SHOWN (D-SHEET) HATCH Ltd. PROJECT NO. H340870	DRAWING NO. H340870-SITE 5B-003 SHEET 3 OF 4 REVISION A

2 LONGITUDINAL SECTION (POWERHOUSE END)
004 003

SCALE: 1:100



S HORIZONTAL SECTION (POWERHOUSE END)

SCALE: 1:100

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COASTAL LABRADOR HYDRO
PHASE 2: POTENTIAL STORAGE

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CHECKED M. McFARLANE

DRAWING
PREPARED S. RUSSELL
CHECKED J. WAYE

PROJECT MANAGER M. McFARLANE

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SITE 5B – POWERHOUSE PROFILE AND SECTION

DRAWING NO. H340870–SITE 5B–004

SHEET 4 OF 4

REVISION A

PLAN – GENERAL ARRANGEMENT SITE 8D

0m 30 60 90 120 150

SCALE: 1:1500

HATCH	NL HYDRO ST. JOHN'S, NL, CANADA
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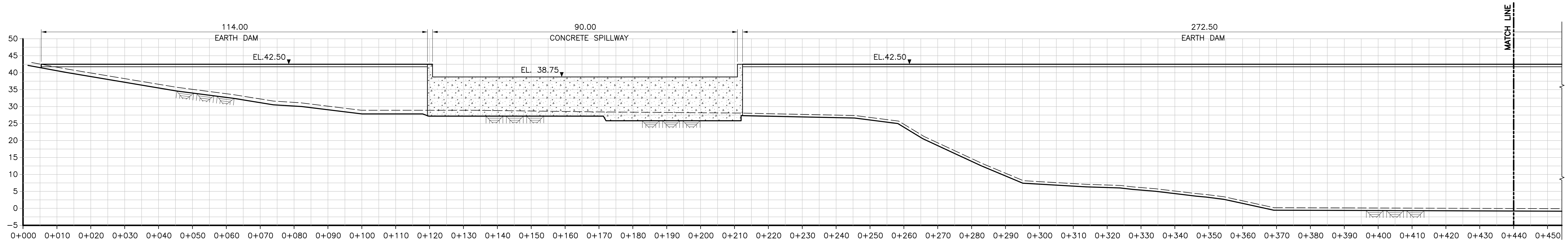
DESIGN PREPARED G. FRANK CHECKED M. McFARLANE DRAWING PREPARED S. RUSSELL CHECKED J. WAYE PROJECT MANAGER M. McFARLANE	SITE 8D – GENERAL ARRANGEMENT PLAN
SCALE 1:1500 (D-SHEET) HATCH Ltd. PROJECT NO. H340870	DRAWING NO. H340870-SITE 8D-001 SHEET 1 OF 3 REVISION A



SECTION – MAIN DAM, SPILLWAY, DIVERSION STRUCTURE, INTAKE AND FISHPASSAGE

A 002 001

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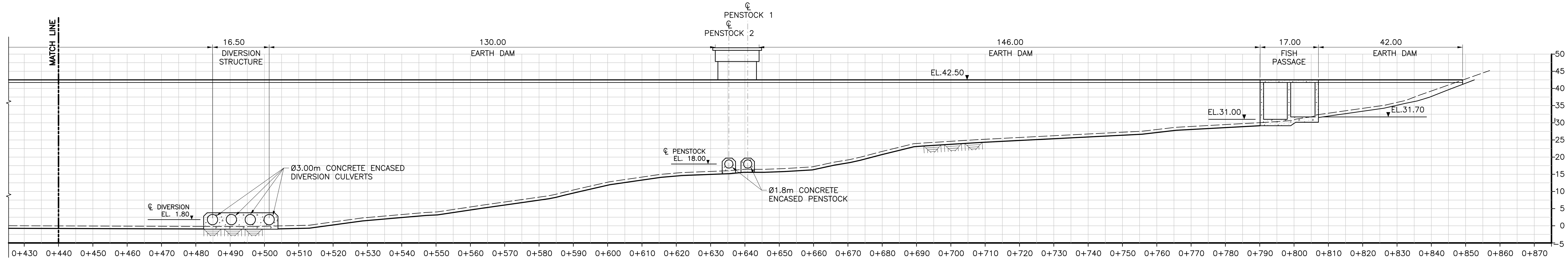

SECTION – MAIN DAM, SPILLWAY, DIVERSION STRUCTURE, INTAKE AND FISHPASSAGE

A 002 001

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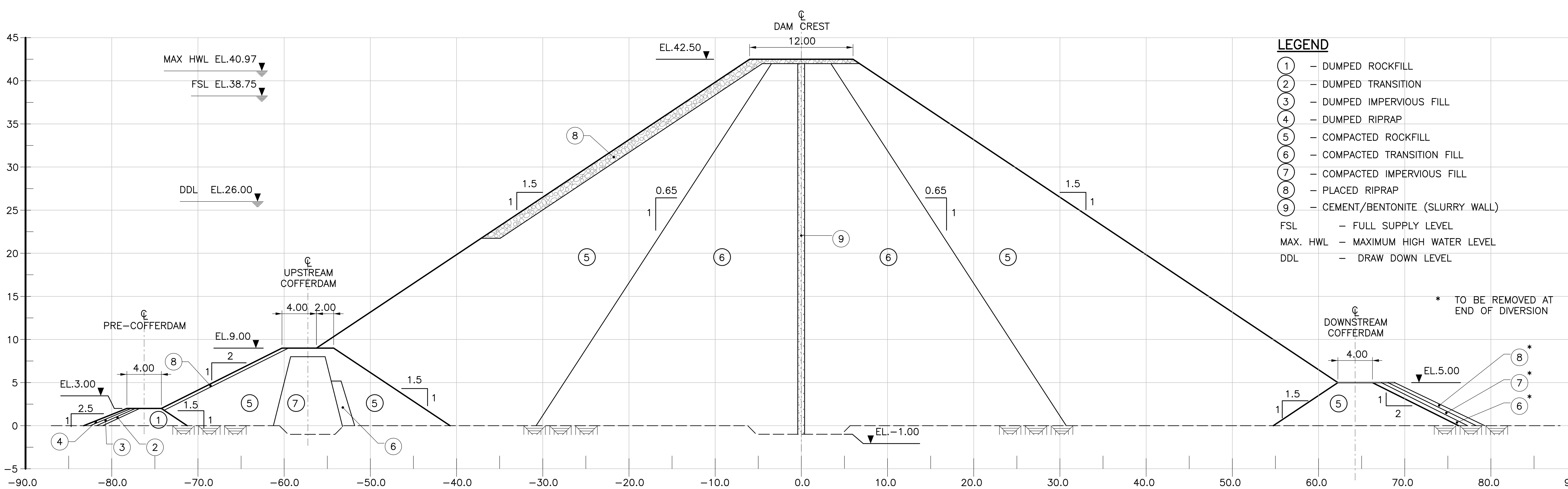

SECTION – MAIN DAM

B 002 001

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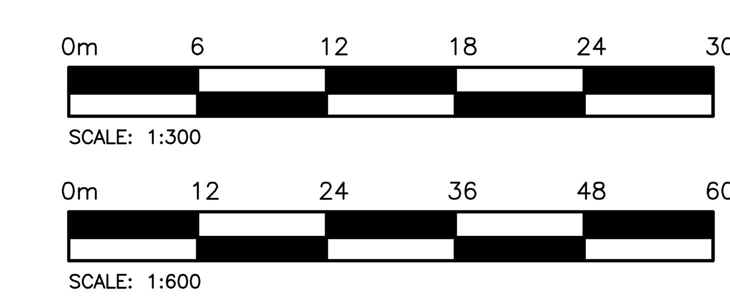

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COASTAL LABRADOR HYDRO
PHASE 2: POTENTIAL STORAGE

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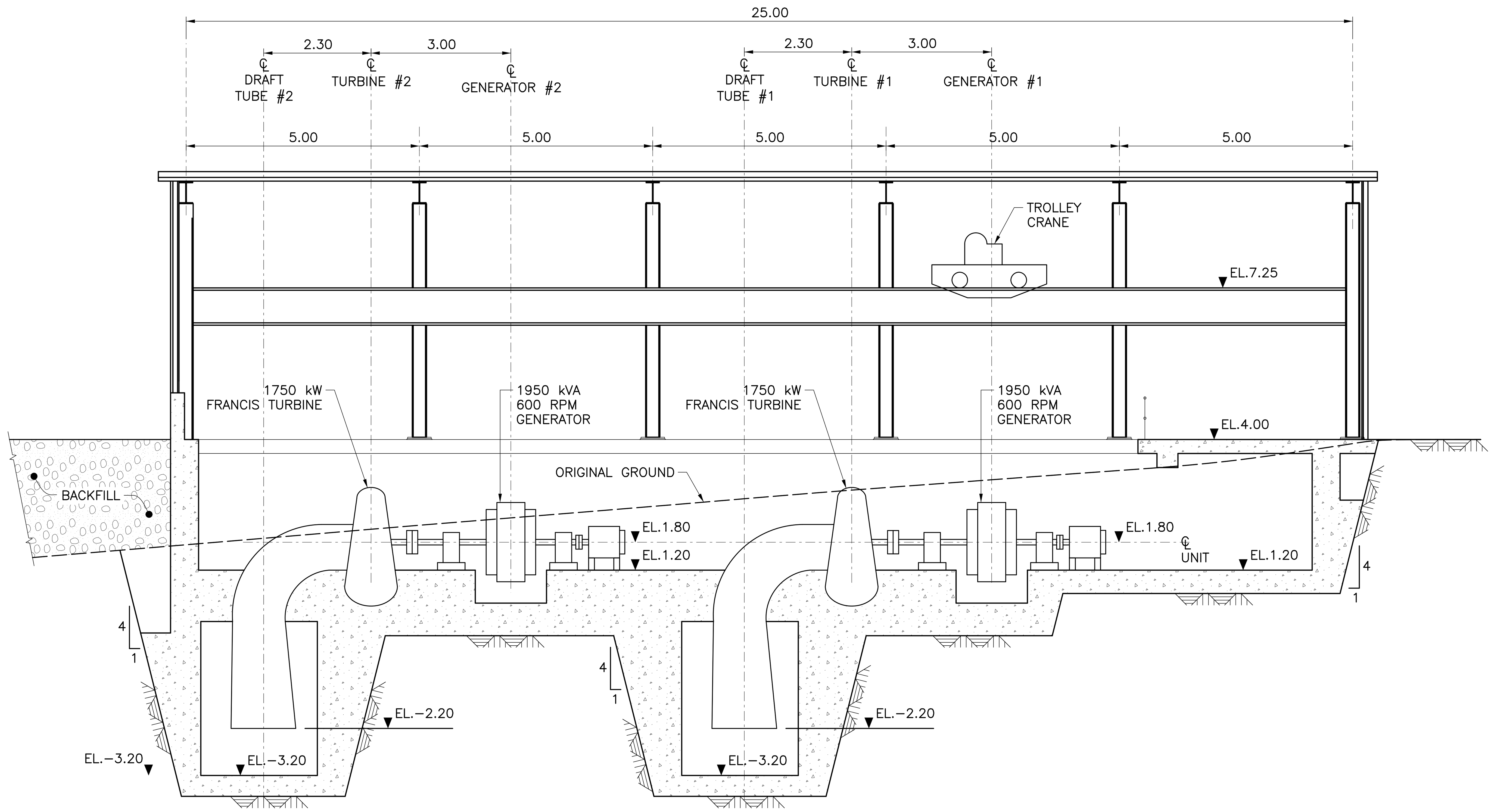
CHECKED	M. McFARLANE
DRAWING	
PREPARED	J. WAYE
CHECKED	S. RUSSELL
PROJECT MANAGER	M. McFARLANE
SCALE	AS SHOWN (D–SHEET)
HATCH Ltd. PROJECT NO.	H340870

SITE 8D –
MAIN DAM SECTIONS

DRAWING NO. H340870–SITE 8D–002

SHEET 2 OF 3

REVISION A



C SECTION – POWERHOUSE
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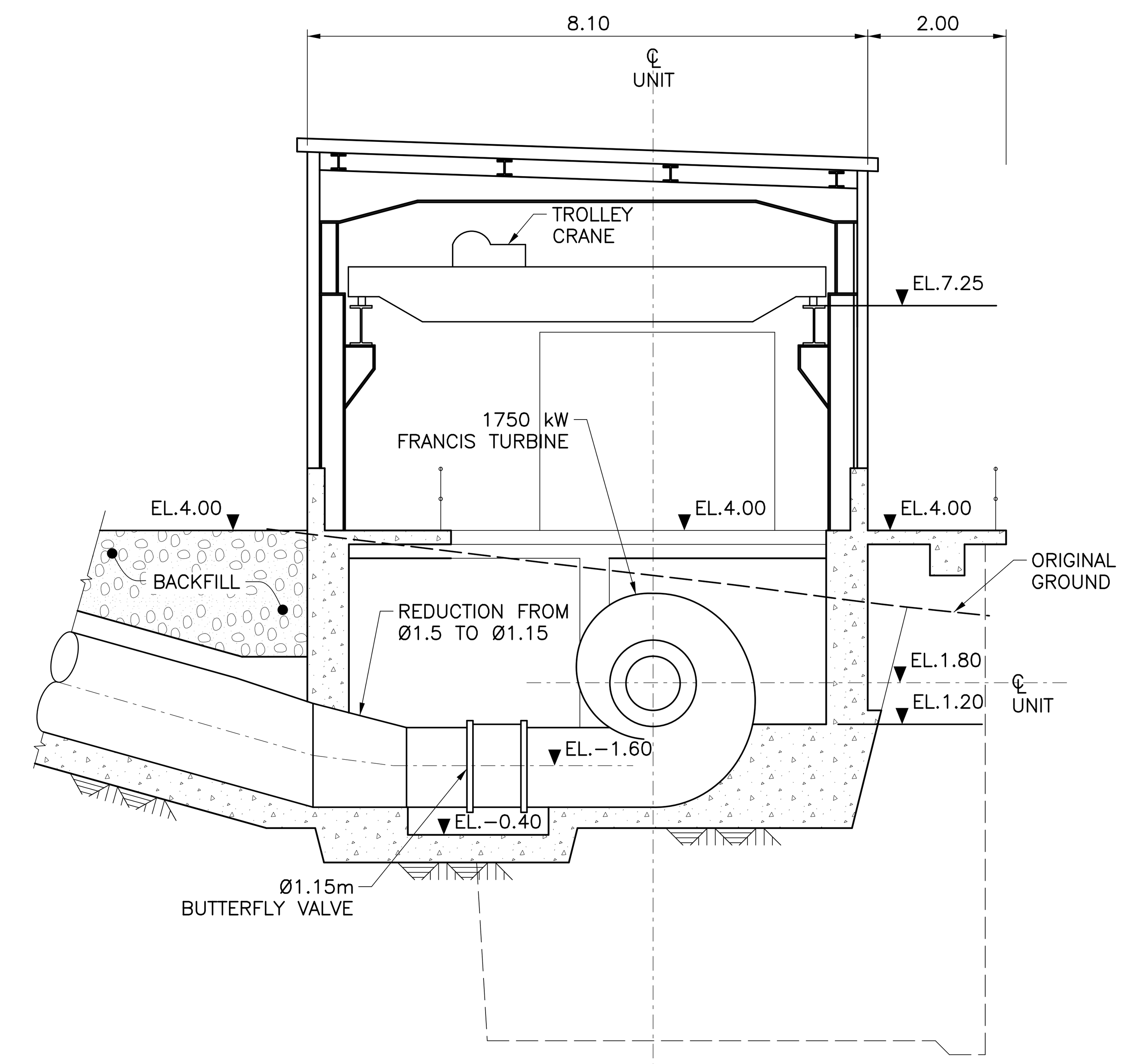

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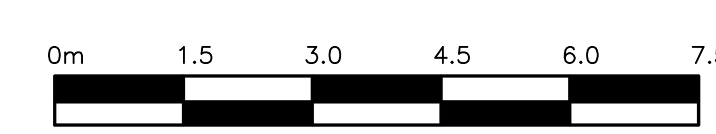

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	COASTAL LABRADOR HYDRO PHASE 2: POTENTIAL STORAGE
DESIGN PREPARED G. FRANK CHECKED M. McFARLANE DRAWING PREPARED J. WAYE CHECKED S. RUSSELL PROJECT MANAGER M. McFARLANE	SITE 8D – POWERHOUSE SECTIONS
SCALE AS SHOWN (D-SHEET) HATCH Ltd. PROJECT NO. H340870	DRAWING NO. H340870–SITE 8D–003 SHEET 3 OF 3 REVISION A

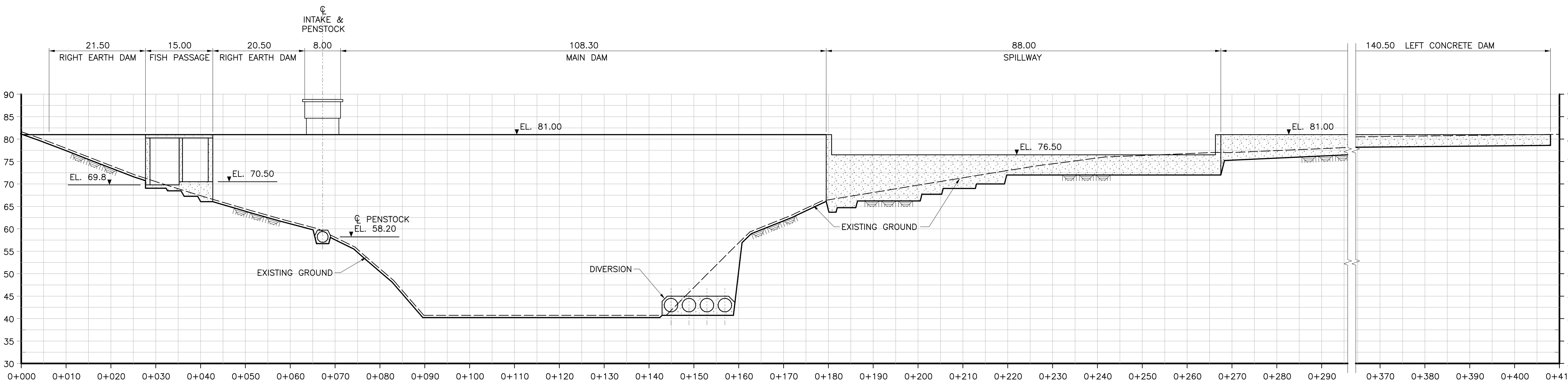
GENERAL ARRANGEMENT PLAN

SCALE: 1:1000

0m 20 40 60 80 100

SCALE: 1:1000

HATCH	NL HYDRO ST. JOHN'S, NL, CANADA
HATCH Ltd.	COASTAL LABRADOR HYDRO PHASE 2: POTENTIAL STORAGE
DESIGN PREPARED G. FRANK CHECKED M. McFARLANE	SITE ALX B – GENERAL PLAN
DRAWING PREPARED J. WAYE CHECKED S. RUSSELL	
PROJECT MANAGER M. McFARLANE	
SCALE AS SHOWN (D–SHEET)	DRAWING NO. H340870–SITE ALX B–001
HATCH Ltd. PROJECT NO. H340870	SHEET 1 OF 3
	REVISION A



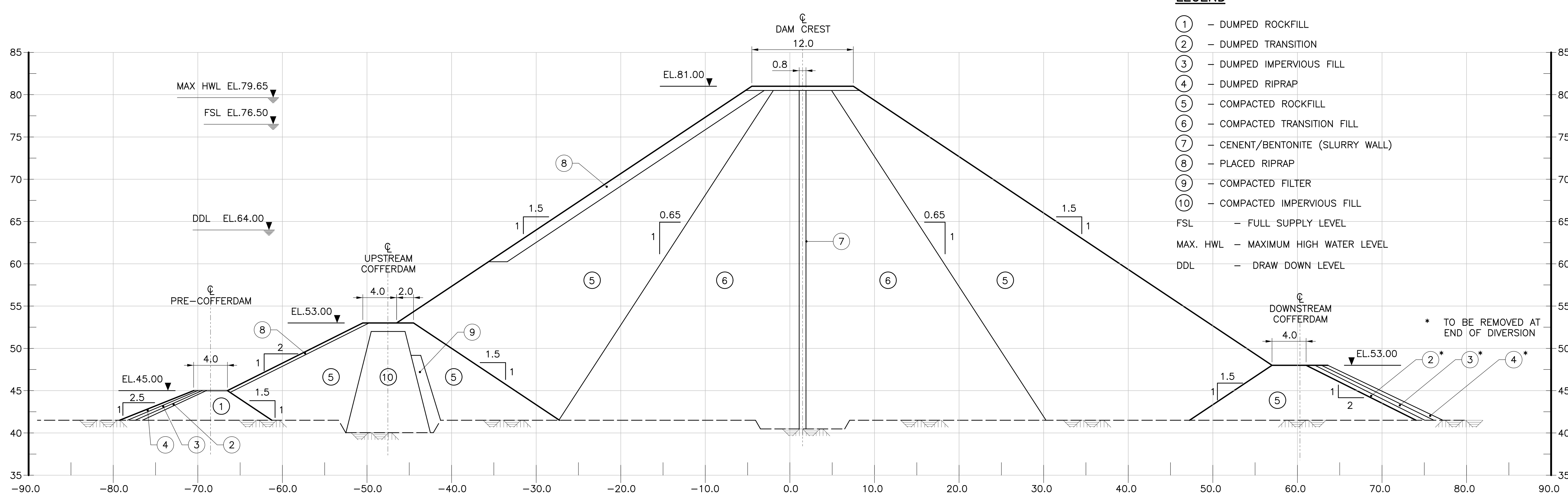
A SECTION – MAIN DAM

002 001

SCALE: 1:500

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



B SECTION – MAIN DAM

002 001

SCALE: 1:300

0m 6 12 18 24 30
SCALE: 1:300

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

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ST. JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: POTENTIAL STORAGE

DESIGN
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CHECKED M. McFARLANE

DRAWING
PREPARED J. WAYE
CHECKED S. RUSSELL

PROJECT MANAGER M. McFARLANE

SCALE AS SHOWN (D–SHEET)

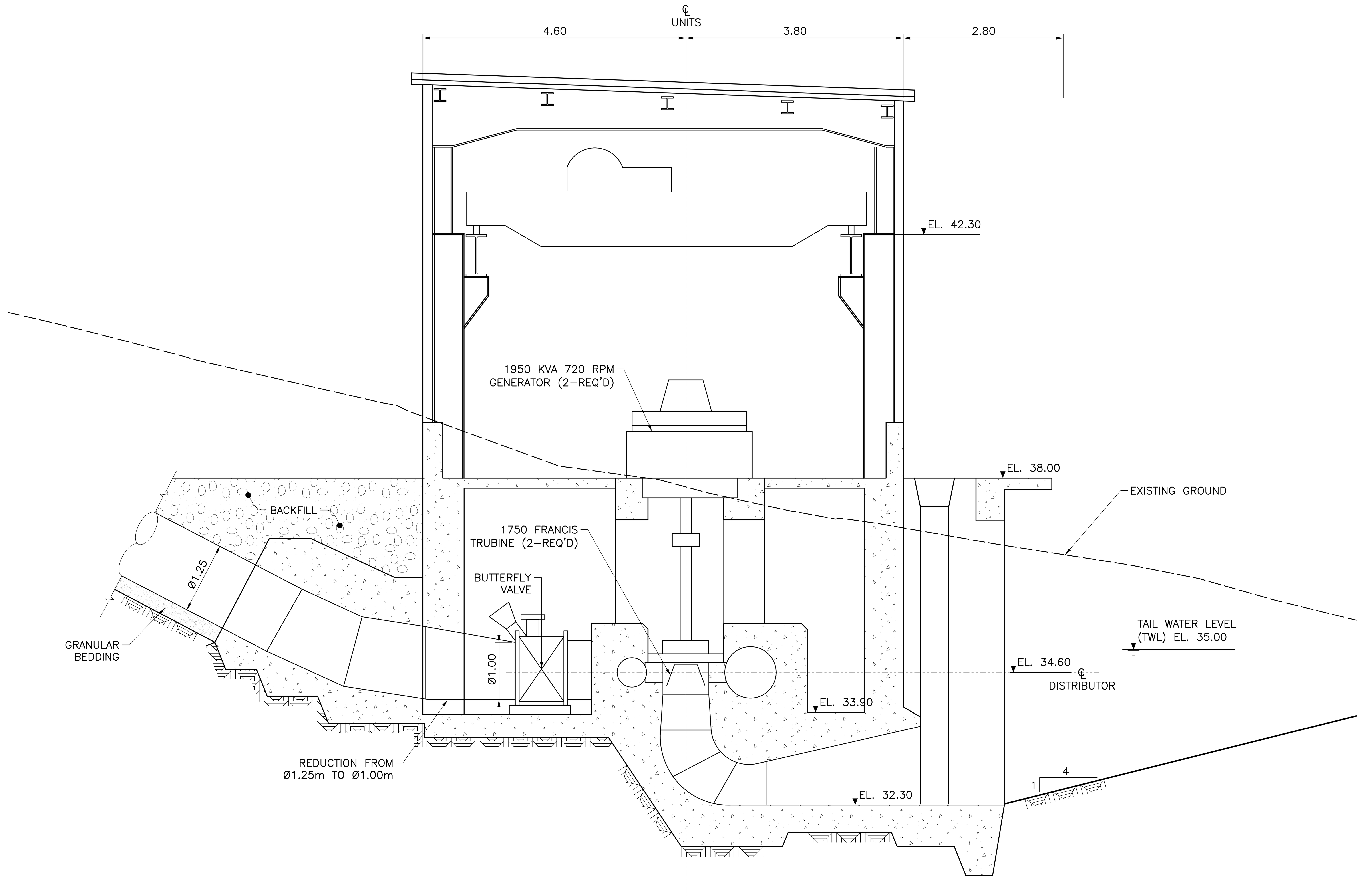
HATCH Ltd. PROJECT NO. H340870

SITE ALX B –
MAIN DAM SECTIONS

DRAWING NO. H340870–SITE ALX B– 002

SHEET 2 OF 3

REVISION A



A
003 | 001

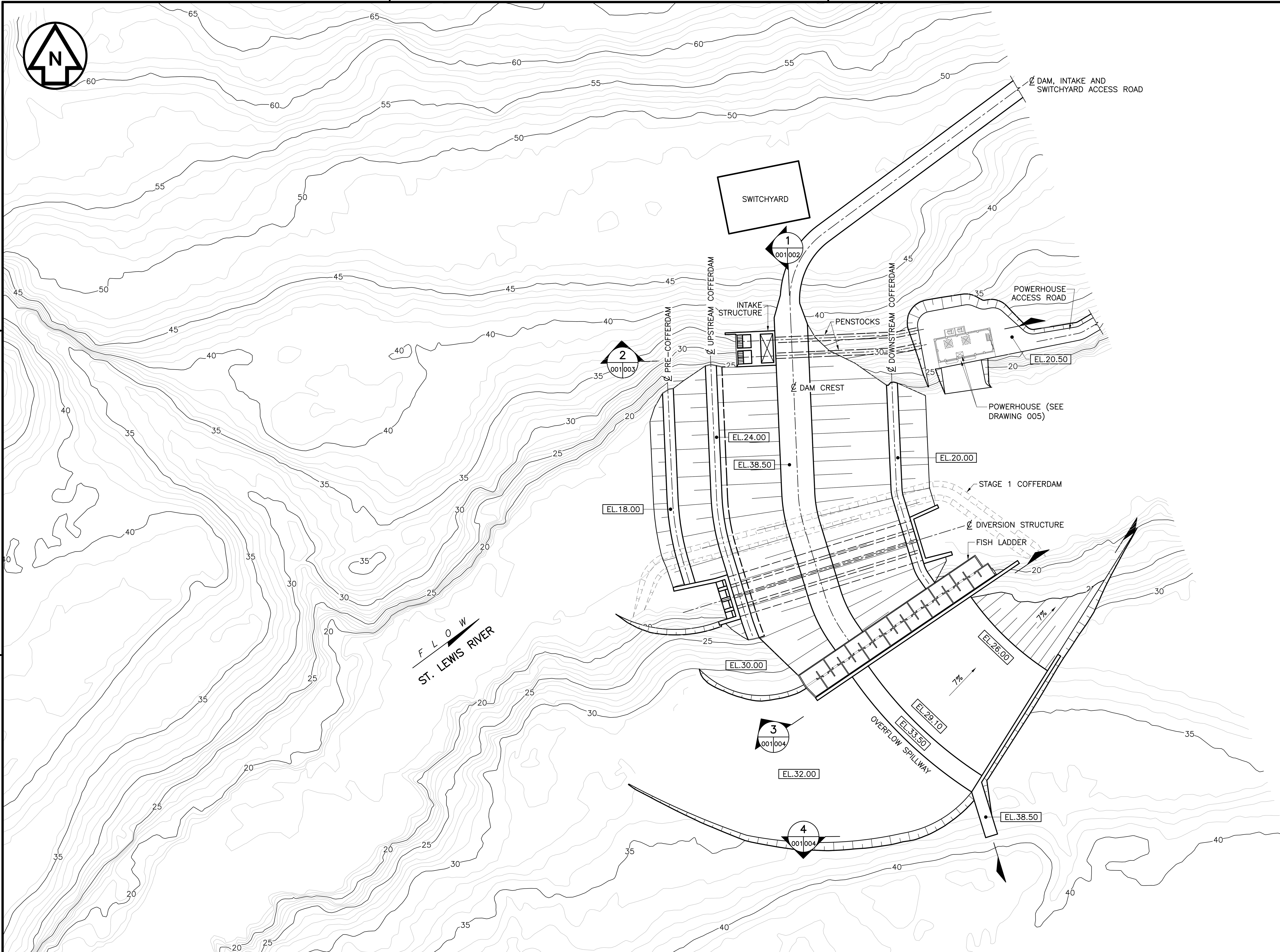
SECTION – POWERHOUSE

SCALE: 1:50

0m 1 2 3 4 5

SCALE: 1:50

HATCH™ 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 J. WAYE CHECKED S. RUSSELL PROJECT MANAGER M. McFARLANE	SITE ALX B – POWERHOUSE SECTION
SCALE AS SHOWN (D-SHEET) HATCH Ltd. PROJECT NO. H340870	DRAWING NO. H340870–SITE ALX B–003 SHEET 3 OF 3 REVISION A

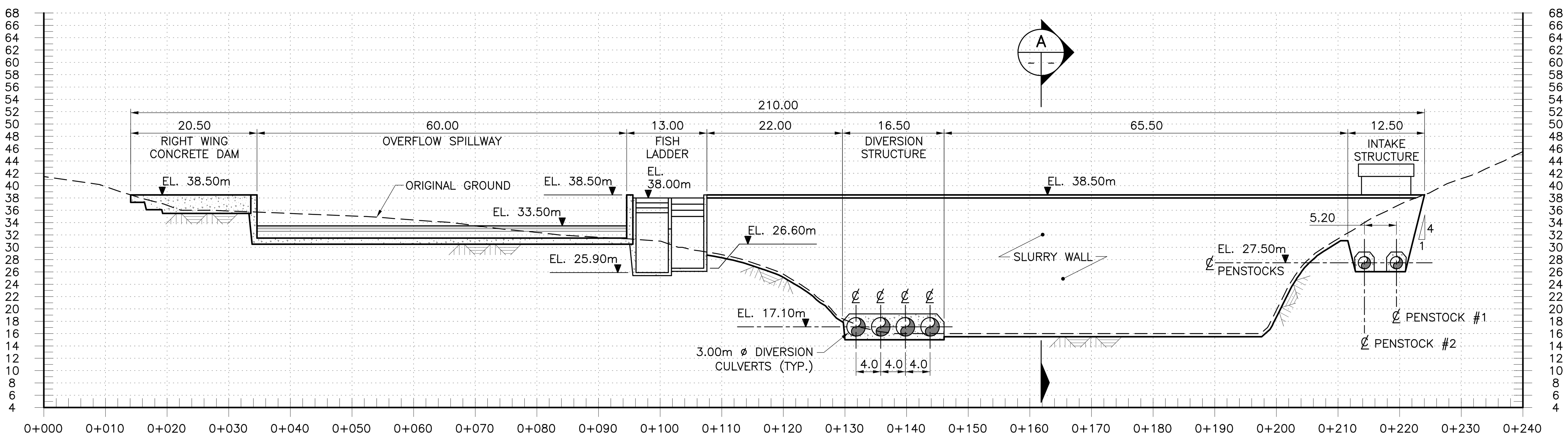


PLAN – GENERAL ARRANGEMENT SITE 8C

0m 15 30 45 60 75

SCALE: 1:750

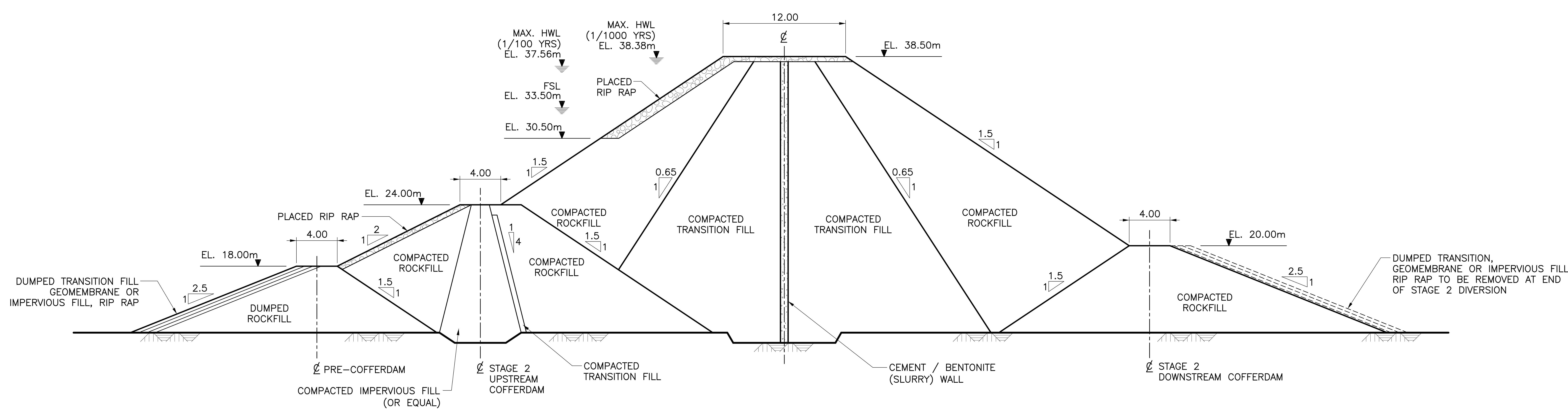
HATCH™ HATCH Ltd.	NL HYDRO ST. JOHN'S, NL, CANADA
	COASTAL LABRADOR HYDRO PHASE 2: POTENTIAL STORAGE
DESIGN PREPARED G. FRANK CHECKED M. McFARLANE DRAWING PREPARED S. RUSSELL CHECKED J. WAYE PROJECT MANAGER M. McFARLANE	SITE 8C–2 – GENERAL ARRANGEMENT PLAN
SCALE 1:750 (D–SHEET) HATCH Ltd. PROJECT NO. H340870	DRAWING NO. H340870–SITE 8C–2–001 SHEET 1 OF 5 REVISION A



1 002 001 PROFLE – RIGHT WING DAM, SPILLWAY, FISH LADDER, EMBANKMENT DAM AND INTAKE

0m 10 20 30 40 50

SCALE: 1:500

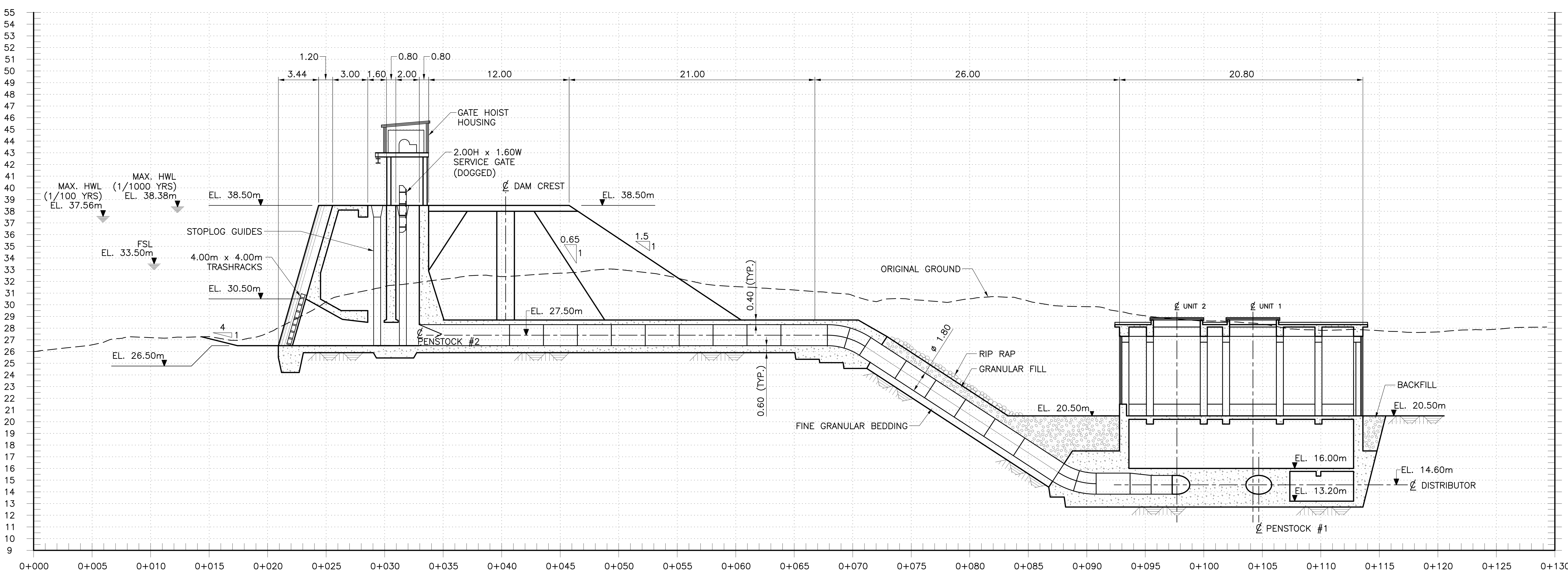


A SECTION – SLURRY WALL EMBANKMENT DAM

0m 5 10 15 20 25

SCALE: 1:250

HATCH 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	SITE 8C–2 – PROFILE AND SECTION
SCALE AS SHOWN (D–SHEET) HATCH Ltd. PROJECT NO. H340870	DRAWING NO. H340870–SITE 8C–2–002 SHEET 2 OF 5 REVISION A



2 PROFILE – INTAKE, PENSTOCK, AND POWERHOUSE

003 | 001

0m 4 8 12 16 20

SCALE: 1:200

HATCH

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NL HYDRO

ST. JOHN'S, NL, CANADA

COASTAL LABRADOR HYDRO
PHASE 2: POTENTIAL STORAGE

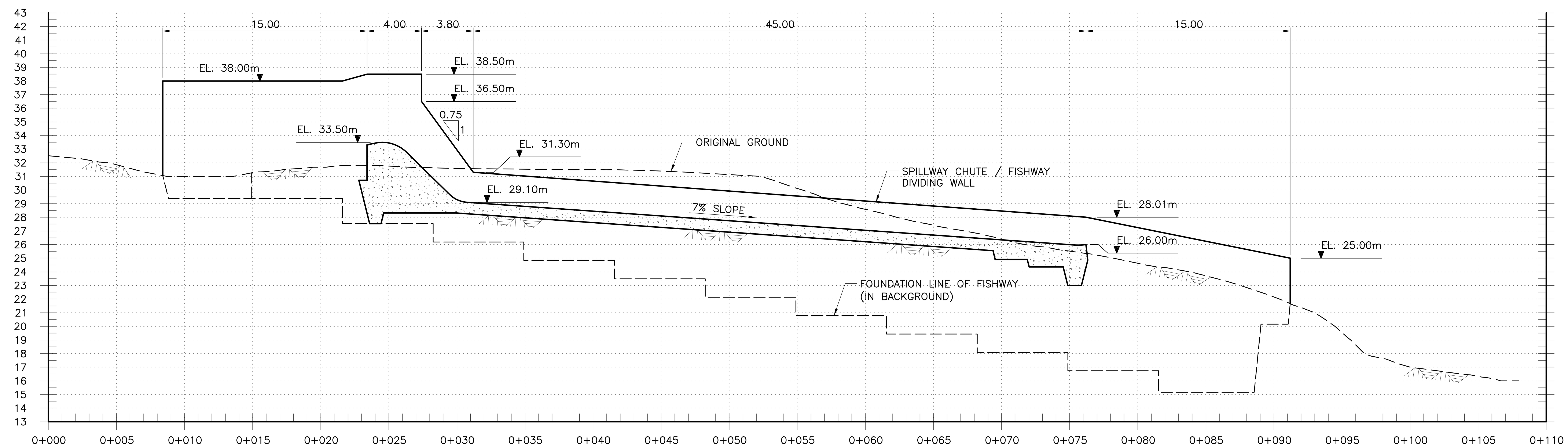
DESIGN	
PREPARED	G. FRANK
CHECKED	M. McFARLANE
DRAWING	
PREPARED	S. RUSSELL
CHECKED	J. WAYE
PROJECT MANAGER	M. McFARLANE
SCALE	1:200 (D-SHEET)
HATCH Ltd. PROJECT NO.	H340870

SITE 8C–2 –
INTAKE, PENSTOCK AND
POWERHOUSE PROFILE

DRAWING NO. H340870–SITE 8C–2–003

REVISION A

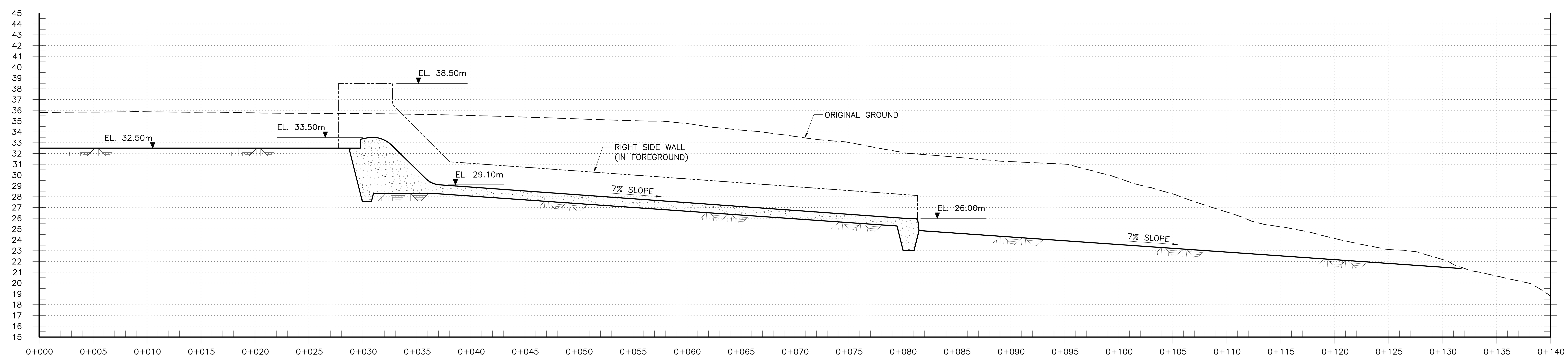
SHEET 3 OF 5



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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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 1:200 (D-SHEET)

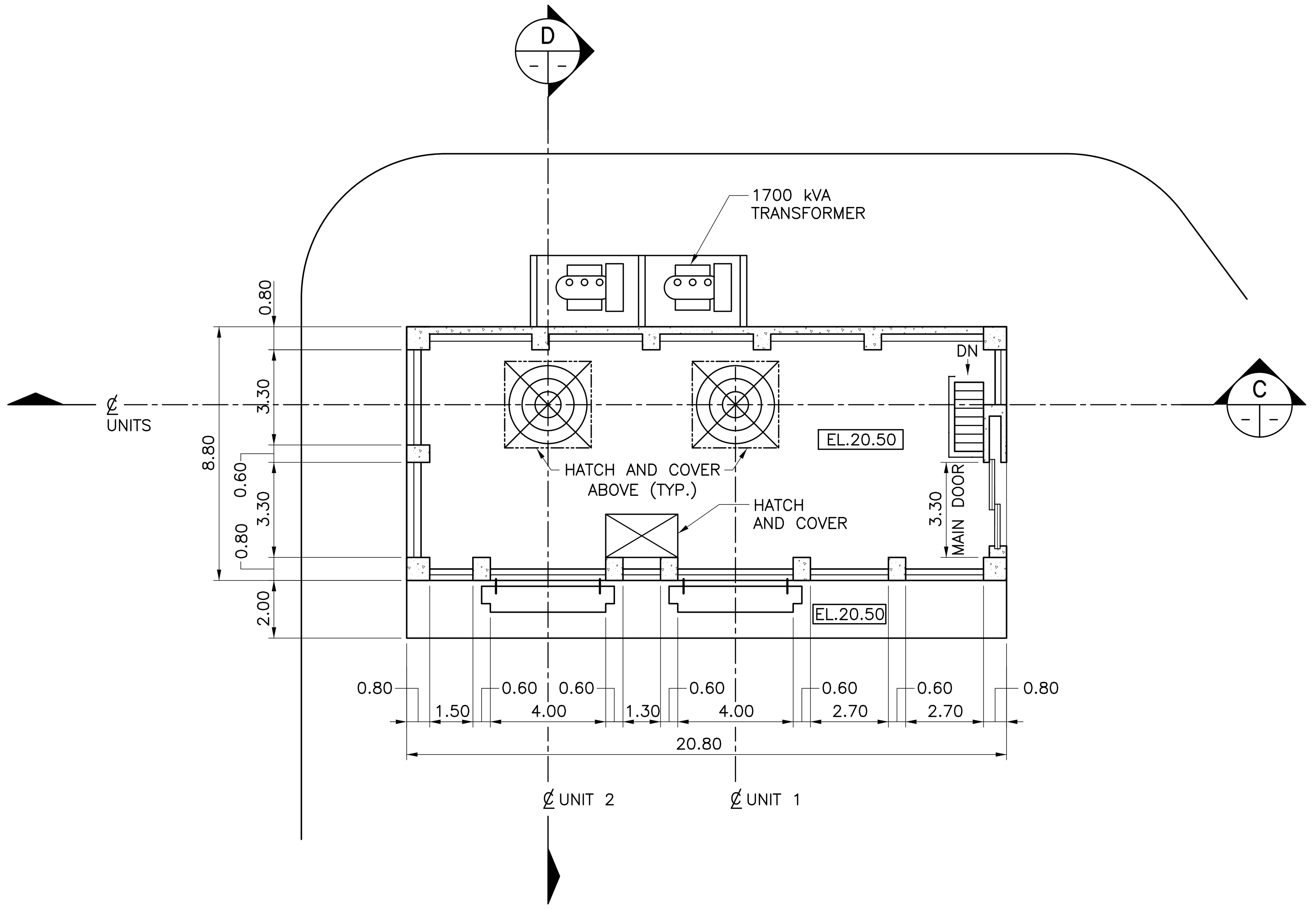
HATCH Ltd. PROJECT NO. H340870

SITE 8C–2 –
SPILLWAY PROFILES

DRAWING NO. H340870–SITE 8C–2–004

SHEET 4 OF 5

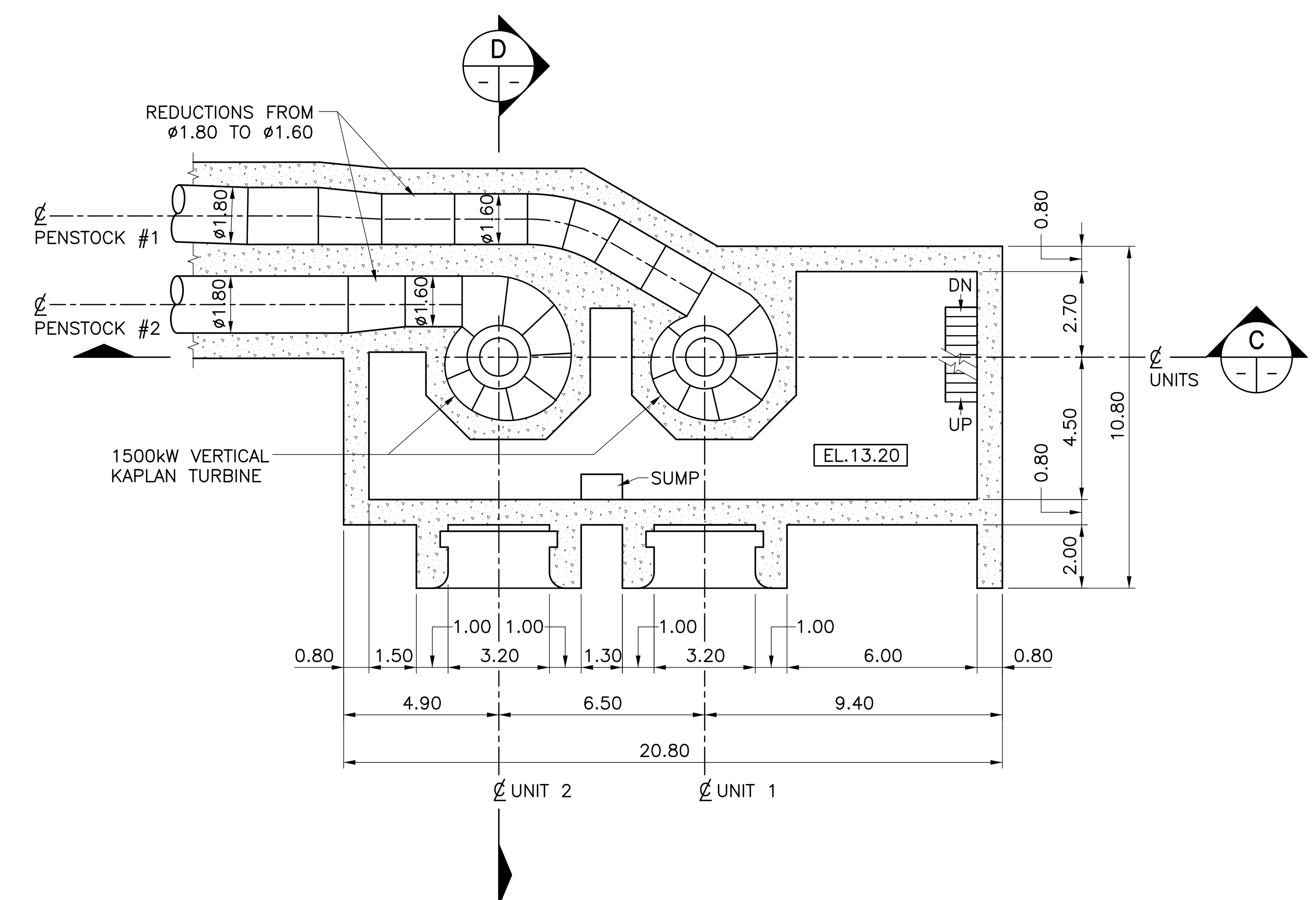
REVISION A



A
POWERHOUSE PLAN @ EL. 23.00m

0m 3 6 9 12 15

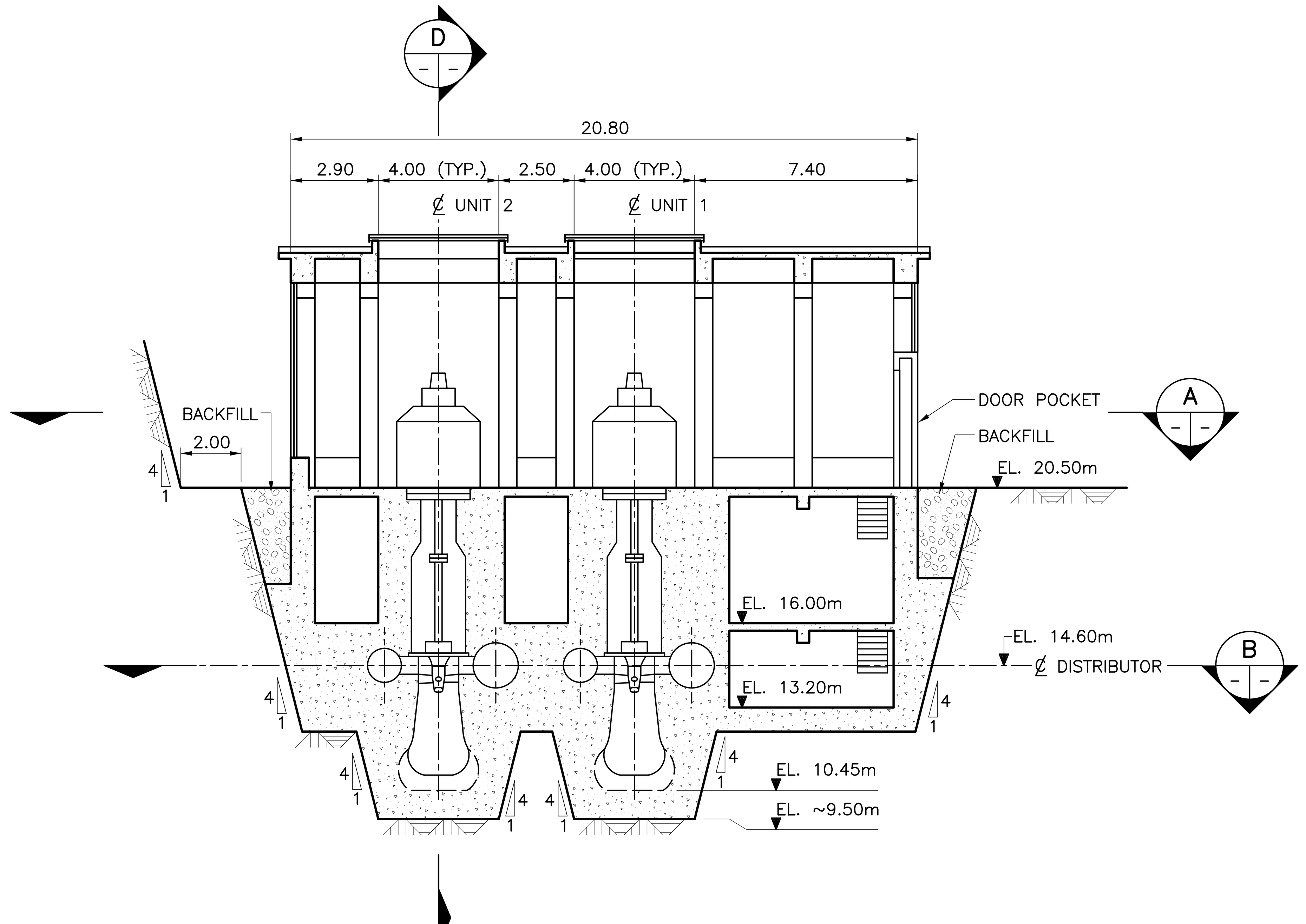
SCALE: 1:150



B
POWERHOUSE PLAN @ EL. 15.70m

0m 3 6 9 12 15

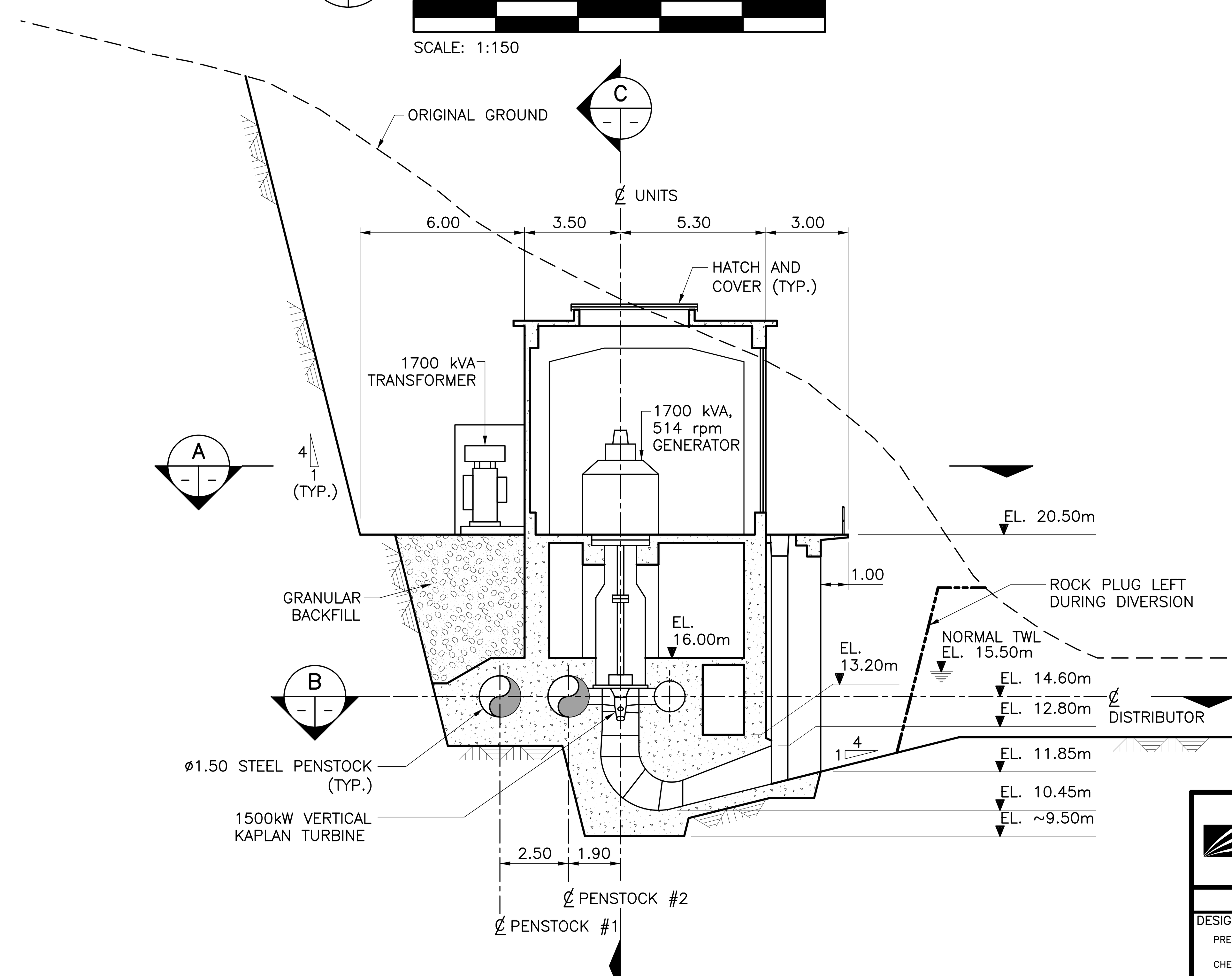
SCALE: 1:150



C
SECTION – CENTERLINE OF UNITS #1 & #2

0m 3 6 9 12 15

SCALE: 1:150

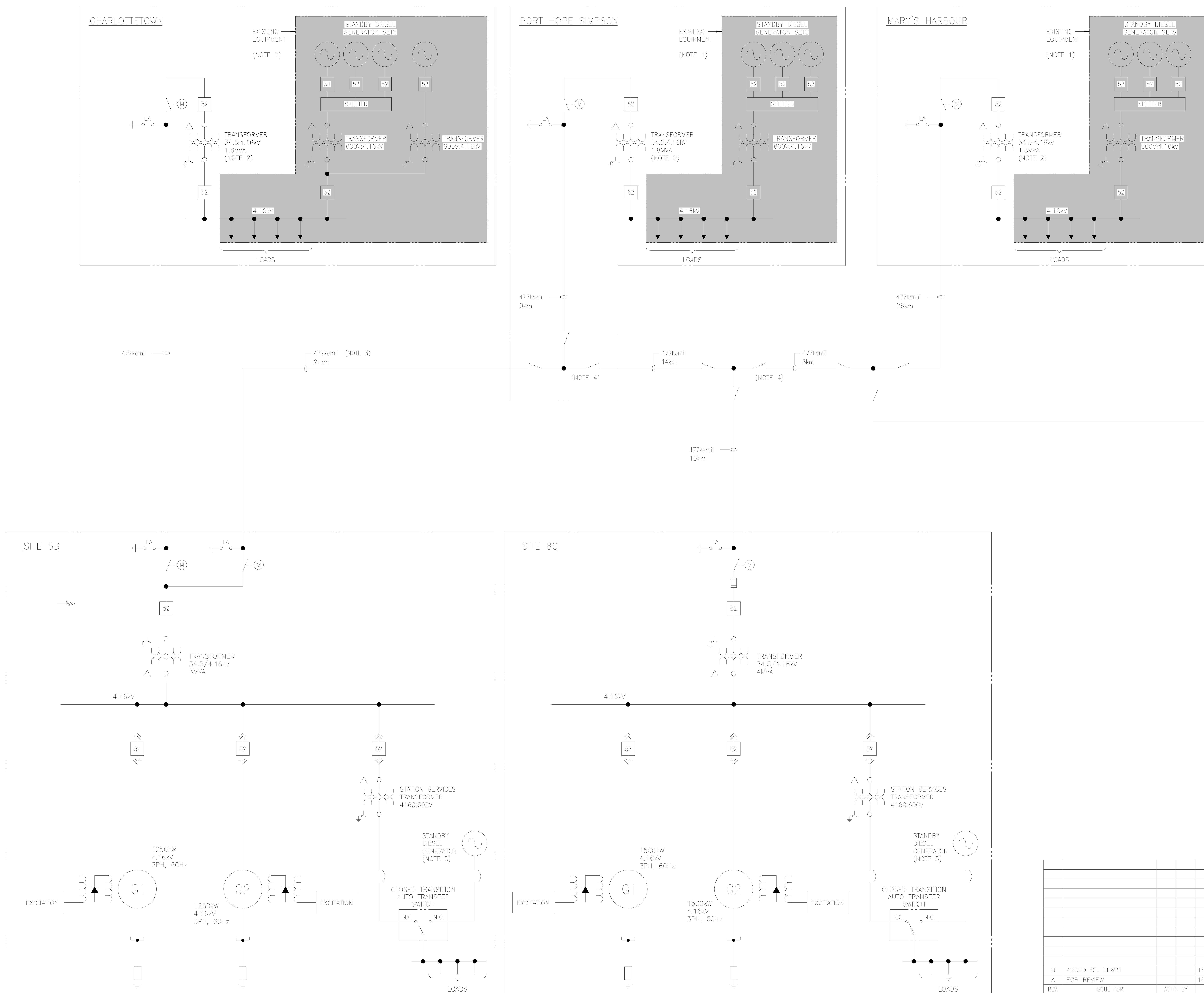


D
SECTION – CENTERLINE OF UNIT #2

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
DESIGN PREPARED G. FRANK CHECKED M. McFARLANE DRAWING PREPARED S. RUSSELL CHECKED J. WAYE PROJECT MANAGER M. McFARLANE	SITE 8C–2 – POWERHOUSE SECTIONS
SCALE 1:150 (D-SHEET) HATCH Ltd. PROJECT NO. H340870	DRAWING NO. H340870–SITE 8C–2–005 SHEET 5 OF 5 REVISION A



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
SHEET 1 OF 1
REVISION B

Attachment 3

Cost Estimates and Project Schedule

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**

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 (Ǿ=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**

HATCH

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

HATCH

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**

HATCH

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

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

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

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

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***

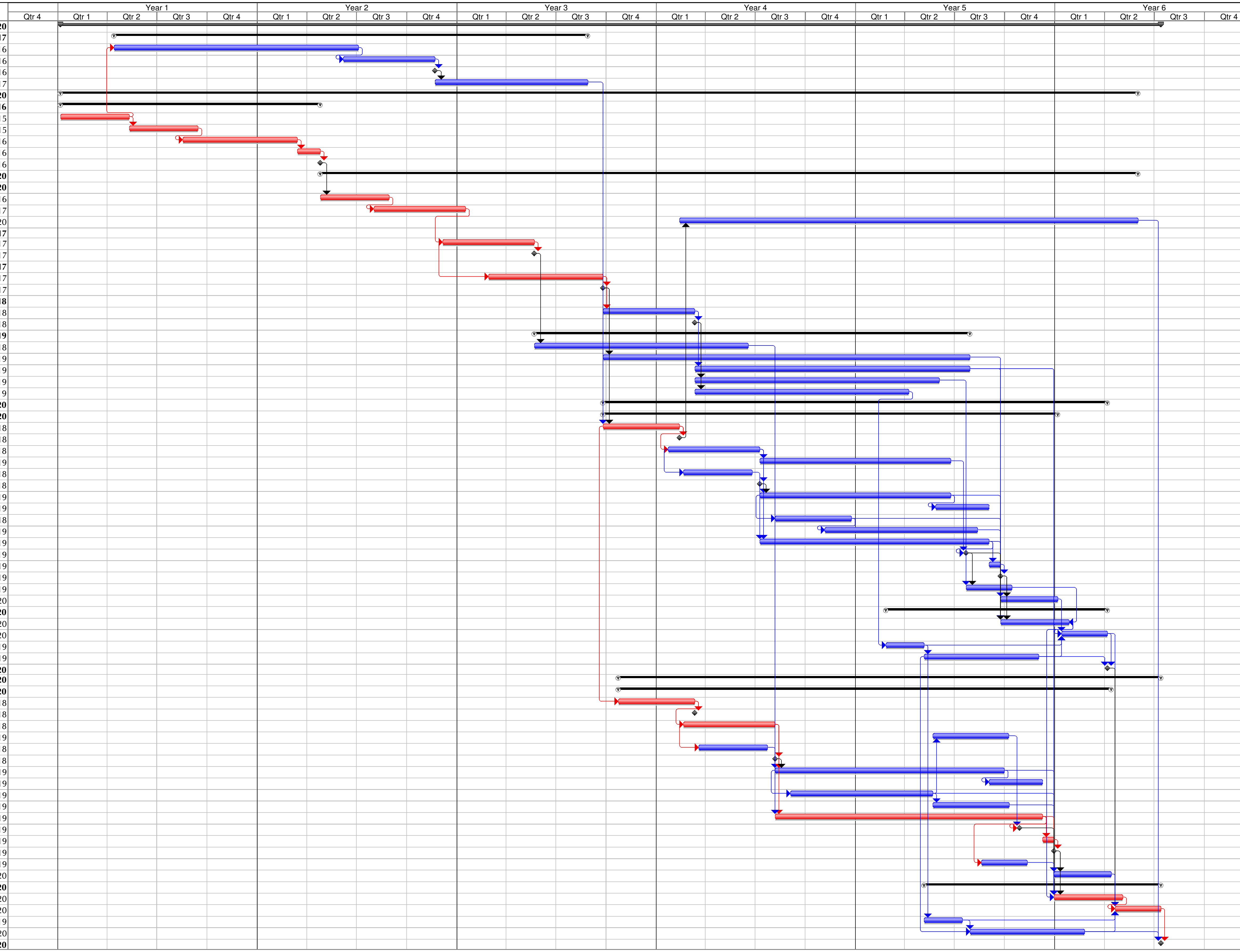
Exclusions:

- 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

HATCH

Critical | Task | Split | Milestone | Summary

Attachment 4

Commentary on Gilbert Bay Golden Cod

Site 5B, Gilbert River, is upstream (west) of Gilbert Bay, and the powerhouse tailrace as proposed would discharge into Gilbert Bay. This bay has a resident population of genetically distinct Atlantic cod referred to as the Golden Cod. In 2005, the Gilbert Bay Marine Protected Area (MPA) was established to protect the Golden Cod and its habitat. The MPA designation does not preclude possible hydroelectric development on lands near the Gilbert River. However, if this site were selected for further consideration, more study would be warranted to define potential effects the development could have on the marine ecosystem downstream. In addition, environmental assessment planning would need to take into account the Golden Cod and the MPA as part of its routine stakeholder identification and issues scoping analysis. It is likely that this exercise would identify that the existence of the MPA and the Golden Cod would require additional stakeholder consultations and detailed assessment of the potential interactions between the project and the downstream Golden Cod population and habitat.

The location of the downstream components (powerhouse and tailrace) of the proposed Site 5B development were selected to maximize head and corresponding energy production, and with a footprint outside the boundaries of the MPA. During environmental studies and final engineering, the final selected coordinates of the powerhouse and tailrace would be fixed to fall outside of the MPA.

80 Hebron Way, Suite 100
St. John's, Newfoundland, Canada A1A 0L9
Tel: +1 (709) 754 6933

80 Hebron Way, Suite 100
St. John's, Newfoundland, Canada A1A 0L9
Tel: +1 (709) 754 6933