Q. **Reference: Reliability and Resource Adequacy Study 2022 Update, Volume III, page 42, line 17 to page 43, line 5.**

Describe all studies and analyses performed of alternatives considered for comparison of the generation/capacity addition alternatives, including comparisons of costs, schedules, needed operating characteristics and risks. Include in the response the date each generation addition alternative was first studied and when it was last revised and updated. Provide copies of any performed.

A. Most of Newfoundland and Labrador Hydro's ("Hydro") portfolio of available resource options has consistently been included in resource planning assessments spanning decades. Most recently, in the 2018 "Reliability and Resource Adequacy Study" ("2018 Filing"),[1] renewable resource options, such as solar generation and battery storage technology, have been included in the resource mix as advances in technology have improved reliability and cost considerations.

The following resource options were discussed at length in the 2018 Filing and the costs escalated in the "Reliability and Resource Adequacy Study – 2019 Update" ("2019 Update").[2] Hydro contracted external consultants to provide cost estimates and schedule updates for the "Reliability and Resource Adequacy Study – 2022 Update" ("2022 Update").[3] The resource alternatives listed herein have been considered in the Reliability and Resource Adequacy Studies.

[1] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018).
[2] "Reliability and Resource Adequacy Study – 2019 Update," Newfoundland and Labrador Hydro, November 15, 2019.
[3] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022.

Wind Generation

Wind generation has been studied as a generation alternative by Hydro for several decades and is updated on a regular basis. The "NL Hydro Wind Generation Alternative: Project Development Estimate,"[4] was provided in support of the 2018 Filing.[5] Project costs were escalated to 2019 dollars in support of the 2019 Update. Please refer to PUB-NLH-288, Attachment 1 for the updated cost estimate Hydro received from Hatch Ltd. ("Hatch") in support of the 2022 Update.[6]

Solar Generation

Solar generation as a resource expansion alternative was first included in the 2018 Filing.[7,8] Project costs were escalated to 2019 dollars in support of the 2019 Update. Please refer to PUB-NLH-288, Attachment 2 for the updated cost estimate Hydro received from Wood Canada Limited ("Wood") in support of the 2022 Update.[9]

Battery Generation

Batteries as a resource expansion alternative were first included in the 2018 Filing.[10,11] Project costs were escalated to 2019 dollars in support of the 2019 Update. Please refer to PUB-NLH-288, Attachment 3 for the updated cost estimate Hydro received from Wood in support of the 2022 Update.[12]

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[4] "NL Hydro Wind Generation Alternative: Project Development Estimate," New Colliers Ltd., November 3, 2018.
[5] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. III, att. 5.
[6] "Wind Integration Study – Project Cost Estimate," Hatch Ltd., July 14, 2022.
[7] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. III, att. 6.
[8] "NL Hydro Solar Generation Alternative: Project Development Estimate," New Colliers Ltd., November 2, 2018.
[9] "Solar Project Preliminary Cost Estimate," Wood Canada Limited, August 22, 2022.
[10] "NL Hydro Battery Storage Alternative: Project Development Estimate," New Colliers Ltd., November 2, 2018.
[11] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. III, att. 7.
[12] "BESS Project Preliminary Cost Estimate," Wood Canada Limited, August 22, 2022.

New Hydroelectric Generation Developments

Hydro has considered the following new hydroelectric generation developments as potential resource options since before the 1980s:

<u>Island Pond Hydroelectric Development</u>

The cost estimate for the construction of the Island Pond Hydroelectric Generating Station was derived from the report, "Studies for Island Pond Hydroelectric Project,"[13] and updated by SNC-Lavalin in 2012. To support the 2018 Filing, the 2012 estimate was derived by escalating the 2012 costs to 2018 dollars.[14] The cost was further escalated to 2019 dollars in support of the 2019 Update. Please refer to PUB-NLH-288, Attachment 4 for the "Evaluation of Island Hydroelectric Generation Expansion Alternatives."

<u>Portland Creek Hydroelectric Development</u>

The cost estimate for the construction of the Portland Creek Hydroelectric Generating Station was derived from the 2007 SNC-Lavalin report, "Feasibility Study for Portland Creek Hydroelectric Project,"[15] and updated by SNC-Lavalin in 2012. To support the 2018 Filing, the 2012 estimate was derived by escalating the 2012 costs to 2018 dollars.[16] The cost was further escalated to 2019 dollars in support of the 2019 Update. Please refer to PUB-NLH-288, Attachment 4 for the "Evaluation of Island Hydroelectric Generation Expansion Alternatives."

<u>Round Pond Hydroelectric Development</u>

The cost estimate for the construction of the Round Pond Hydroelectric Generating Station was derived from the report, "Round Pond Feasibility Study."[17] To support the 2018 Filing, the estimate was derived by escalating the 2012 costs to 2018 dollars.[18] The cost was further

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[13] "Studies for Island Pond Hydroelectric Project," SNC-Lavalin, December 2006, <https://www.assembly.nl.ca/business/electronicdocuments/MuskratFalls/Exhibit5b-IslandPond.pdf>.
[14] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. III, att. 8.
[15] "Feasibility Study for Portland Creek Hydroelectric Project," SNC-Lavalin, 2007.
[16] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. III, att. 9.
[17] "Round Pond Feasibility Study," Shawinigan Newfoundland Ltd., 1988.
[18] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. III, att. 10.

escalated to 2019 dollars in support of the 2019 Update. Please refer to PUB-NLH-288, Attachment 4 for the "Evaluation of Island Hydroelectric Generation Expansion Alternatives."

Exploits River Hydroelectric Generation Expansion: Badger Chute and Red Indian Falls

The cost estimate for the construction of the Badger Chute and Red Indian Falls Hydroelectric Generation alternatives were originally developed in 1979 as part of an Exploit's River Hydro Inventory Study, completed by Shawmont Newfoundland Ltd. for Price (Newfoundland) Pump and Paper Ltd. The Badger Chute alternative was revisited in 2002 by AMEC E&C Services Ltd, where it was the subject of a high-level concept review and cost update. The estimate was later updated in 2005 by SGE Acres Ltd. To support the 2018 Filing, the estimate was derived by escalating the 2012 costs to 2018 dollars.[19] The cost was further escalated to 2019 dollars in support of the 2019 Update. Please refer to PUB-NLH-288, Attachment 4 for the "Evaluation of Island Hydroelectric Generation Expansion Alternatives."

Additional Generation at Existing Hydroelectric Generation Facilities

Hydro has considered the following hydroelectric generation developments at existing hydroelectric generation facilities as potential resource options since the 1980s:

Unit 8 at the Bay d'Espoir Hydroelectric Generating Facility ("Bay d'Espoir Unit 8")

The cost estimate for the construction of Bay d'Espoir Unit 8 is an AACE[20] Class 3 Estimate completed by SNC-Lavalin in 2017.[21] The cost was further escalated to 2019 dollars in support of the 2019 Update. Please refer to PUB-NLH-288, Attachment 4 for the "Evaluation of Island Hydroelectric Generation Expansion Alternatives."

Unit 3 at the Cat Arm Hydroelectric Generating Station ("Cat Arm Unit 3")

The original cost estimate for the addition of Cat Arm Unit 3 was originally prepared by Shawmont Newfoundland Ltd. in 1985. The cost estimate for the construction of the Round

[19] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. III, att. 11.

[20] Association for the Advancement of Cost Engineering ("AACE").

[21] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. III, att. 12.

Pond Hydroelectric Generating Station was derived from the report, "Round Pond Feasibility Study," Shawinigan Newfoundland Ltd. in 1988. To support the 2018 Filing, the estimate was derived by escalating the 2012 costs to 2018 dollars.[22] The cost was further escalated to 2019 dollars in support of the 2019 Update. Please refer to PUB-NLH-288, Attachment 4 for the "Evaluation of Island Hydroelectric Generation Expansion Alternatives."

Thermal Generation

Hydro has consistently considered simple-cycle and combined-cycle combustion gas turbines as a potential resource options. A "Gas Turbine Alternatives Report"[23] was provided In support of the 2018 Filing.[24] Project costs were escalated to 2019 dollars in support of the 2019 Update. The proposed federal "Clean Electricity Standard" has raised questions about resource options that would traditionally have been recommended, including whether they will be a viable future resource option (i.e., fossil fuel-burning combustion turbine). In the 2022 Update, Hydro committed to continue to assess thermal generation as a resource option in relation to the proposed Clean Electricity Standard and investigate gas turbines with a renewable fuel source as a resource option in the Reliability and Resource Adequacy Study – 2023 Update ("2023 Update").

Hydro reached out to Hatch to review the availability and estimates for combustion turbines that could utilize bio-diesel or hydrogen fuel. The "Combustion Turbine Screening Final Study Report,"[25] provided as PUB-NLH-288, Attachment 5, was received after the filing of the 2022 Update. The report considers the use and sourcing of biodiesel, ethanol, and hydrogen to generate electricity, including technical limitations as well as a Class 5 cost estimate. This report will be included in the 2023 Update.

Hydro notes that although it now has further information with respect to gas turbine alternatives, in particular the use, sourcing and cost of biofuel technology, a comprehensive feasibility review of gas turbine alternatives is necessary to determine whether it is a viable,

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[22] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. III, att. 10.
[23] "Gas Turbine Plant Alternatives," Newfoundland and Labrador Hydro, November 2018.
[24] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018), vol. III, att. 14.
[25] "Combustion Turbine Screening Final Study Report," Hatch Ltd., rev. October 28, 2022 (originally issued October 17, 2022).

least-cost option that would fit Hydro's need as a resource. The range of additional analysis includes determination of possible site locations, land purchase requirements, fuel supply considerations, water supply considerations, engine selection, and electrical interconnection and environmental impacts in the Northeast Avalon area. Hydro will continue with the analysis in preparation for the 2023 Update as well as to consider in the preparation of documents necessary for any future application for construction of Bay d'Espoir Unit 8.

Capacity Assistance and Curtailable Load

Please refer to the 2022 Update[26] for Hydro's assumptions on Capacity Assistance and Curtailable Load.

Rate Structure and Customer Demand Management

Please refer to the 2022 Update[27] for details and reports on this resource option.

Market Purchases

As discussed in the 2022 Update,[28] to date Hydro has not secured any firm capacity support from external markets for a duration of more than one month and does not have the information to assume that such solutions would be available to meet long-term planning requirements. Market purchases were excluded in the analysis as a potential firm resource option. Hydro will continue to evaluate this option in future updates.

[26] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, vol. I, sec. 4.2.2.
[27] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, vol. III, sec. 7.1.1.
[28] "Reliability and Resource Adequacy Study – 2022 Update," Newfoundland and Labrador Hydro, October 3, 2022, vol. III, sec. 7.1.2.

HATCH

H-369130
14th July 2022

Newfoundland and Labrador Hydro
Wind Integration Study (24 Ea x 4.26 MW = 100 MW)
Enercon E115: 4.26 MW, Class 1A Machine, 77/92 m hub, 115.7 m rotor
Project Cost Estimate

Item	Description	Total, CA$	Comments
	Construction Costs		
1	**Turbine Generators**		
	Turbine supply, inc. transport from port to site	65,000,000	For 24 turbines
	Turbine transport from Germany to Canada	6,441,492	For 24 turbines
	Turbine assembly, crane cost and tower erection	5,473,500	For 24 turbines
	Turbine assembly, in-tower mechanical/electrical	3,204,000	For 24 turbines
	Total - Turbine Generators	**80,118,992**	**3,338,000 $ / turbine**
2	**Construction Indirects & General Items, Civil and Electrical**		
2.1	General Costs / Suppervision & Site Cost	854,400	
2.2	Surveying	569,600	
2.3	QA/QC Subcontract	0	Included in rates below
	Total Construction Indirects & General Items	**1,424,000**	
3	**Civil Works**		
3.1	New Access Roads	4,981,553	332,000 $ / km 15 km of access road
3.2	Crane Pads and Erection Areas	1,420,013	59,200 $ / turbine
3.3	Foundation for Wind Turbines	38,407,992	2,197,000 $ / turbine
	Total Civil Works	**44,809,557**	**1,867,000 $ / turbine**
4	**Electrical Works**		
4.1	Tranmission line 138 kV	6,500,000	5 km
4.2	Collector network 34.5 kV	22,500,000	15 km total collector system
4.3	Transformer including breaker 138 kV	3,500,000	
4.4	E-House c/w switchgear 34.5 kV	2,000,000	

	Total Electrical Works	**34,500,000**	
	TOTAL CONSTRUCTION COSTS	**160,852,550**	**1,609 $ / kW**
5	**Indirects**		
5.1	Engineering & Project Management & Site Supervision	5,464,600	
5.2	Owner Capital Investment in Operations Support	2,358,500	
5.3	Accomodation / Mess & Travel Costs	623,000	
5.4	Temporary Construction Facilities	222,500	
	TOTAL Indirects	**8,668,600**	**87 $ / kW**
6	**Contingency**		
6.1	**Owners Contingency**		
	Owners Contingency (Intended to be P50)	29,904,930	Contingency of 15%
	Total Owner Costs	**29,904,930**	
	TOTAL	**199,426,079**	**1,994 $ / kW**

Solar Project Preliminary Cost Estimate

254388-0000-DF00-STY-0001

August 22, 2022

Wood Canada Limited
600–2020 Winston Park Drive
Oakville, ON L6H 6X7

wood.

APPROVALS

Igor Bozic	August 22, 2022
Prepared by: Igor Bozic	Date
Lewis Hann	August 22, 2022
Checked by: Lewis Hann	Date
Lewis Hann	August 22, 2022
Approved by: Lewis Hann	Date

Professional Stamp

PROVINCE OF NEWFOUNDLAND AND LABRADOR
pegnl ENGINEERING PERMIT D0018
Wood Canada Limited
02020
Signature or Member Number
(Member-in-Responsible Charge)

IMPORTANT NOTICE

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REVISION HISTORY

Rev.	Description	Prepared By	Checked By	Approved By	Date
A	Issued for review	IB	LH	LH	07/12/2022
B	Issued for use	IB	LH	LH	07/28/2022
C	Reissued for use	IB IB	LH LH	LH LH	08/22/2022

Table of Contents

1. Introduction

Newfoundland and Labrador (NL) Hydro is looking for an opportunity to introduce photovoltaic (PV) solar systems in Central Newfoundland and Labrador West. Solar energy projects will diversify the NL Hydro generation mix and provide an opportunity to pair with energy storage solutions. The specific locations of the solar power systems have not been determined. However, the sites are expected to be near Gander and Labrador City and connected to existing terminal station on a 69kV bus in NL or 46kV bus in Labrador.

2. Purpose and Scope

The purpose of the report is to provide an indicative (Class 5) cost estimate for a 10MWac and 20MWac solar farm with integrated BESS system. The solar farm would be connected to the existing terminal station at 46kV or 69kV bus. This estimate includes relevant MV substation interconnection components needed to integrate with the existing terminal stations. With the respect to equipment rating and selection, 46kV insulation class will likely fall under the same category as 69kV. Therefore, for the purpose of this estimate, 69kV voltage level have been considered. Costs associated with the Battery Energy Storage System (BESS) have been identified to enable removal of these values for projects where is BESS will not be required.

Wood has provided assumptions based on industry standards and previous experience for utility scale ground mounted PV solar farms as follows:

- Latest PV modules and inverter technologies
- MV collector system design including substation requirements
- Project scheduling and major project milestones
- Developmental activities such as field investigation (ex. Geotech report), desktop studies, permitting, preliminary & detailed engineering, environmental studies, licenses, etc.
- Major equipment costs
- Construction cost for both DC field and upgrades at the existing 69kV terminal station
- Supporting activities during the construction stage (Site management & monitoring, owner engineer costs, safety, equipment rental, etc.)

3. System Characteristics

This section describes technologies and technical characteristics of the major components for DC solar system, DC/AC conversion (solar inverters), DC coupled BESS, MV collector system including associated cabling, substation components required at the terminal station including main power transformer, breaker, disconnect switch, VAR compensation, protection and metering.

3.1 Solar PV System

3.1.1 PV module

Over the course of the last few years PV solar technology has been improving exponentially and efficiency has increased from a low 15% to mid 20%. Solar PV technology voltage ratings have increased from 600Vdc to 1000Vdc and most recently PV modules rated at 1500Vdc have become available. The industry and electrical safety codes have standardized at this higher voltage level and now it is widely used for utility scale solar projects. 1000Vdc systems are still available however they are generally used for smaller applications such as residential or roof mounted installation.

PV module manufacturers will normally provide a linear power warranty which runs up to 25 to 30 years. This generally means that manufacturer guarantees 90% capacity at 10 years, and 80% at 25 years (See Figure 1 below).

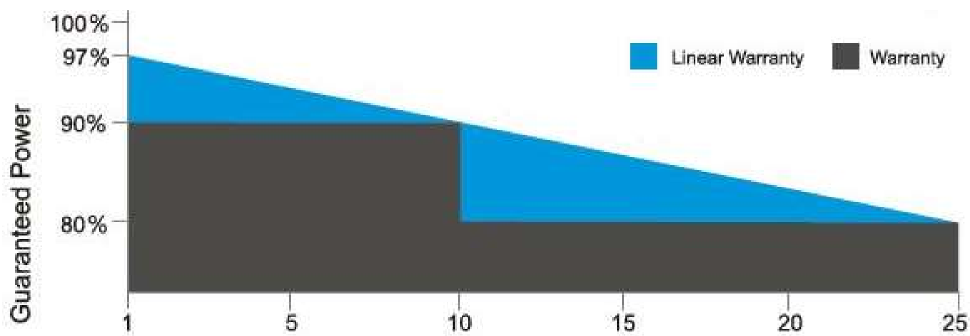


Figure 1: PV module linear warranty

For the remainder of the solar plant, typical industry standard for a lifespan is 20 to 30 years.

There are two different technologies used for commercial projects and they are based on mono-crystalline and poly-crystalline silicone (Si) structure. Mono-crystalline technology is slightly more efficient however, and poly-crystalline design has been improving with efficiency exponentially increasing. As of today, the most common PV solar module available commercially for utility scale solar panel is based on poly technology utilizing half cell and bifacial design. In today's market, the common power output for a typical PV module, ranges from 400W to 600W range per PV module.

As PV module standard size is approximately 2m x 1m, half cell technology allowing for more modules to fit on the same area where one half operates independently of the other, allowing for additional yield due to reduced shading impact (See Figure 2 below).

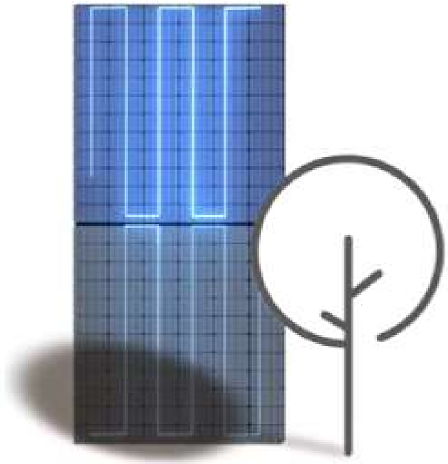


Figure 2: PV module, half cell design

The PV module bi-faciality allows for additional generation from the back of the module from the reflected (indirect) irradiance. The % reflectance depends on type of the reflective elements (albedo effect). The lighter the finished grade, % yield is better and reaching as high as 25%. Considering that our Canadian climate accounts for number of days with snow on the ground, this would benefit for the overall generation (See Figure 3).

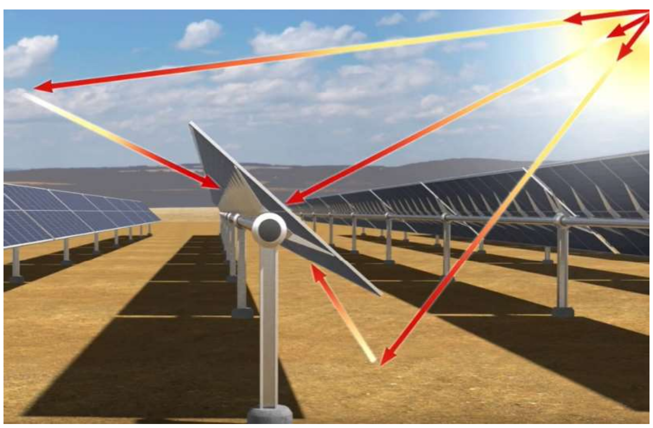


Figure 3: Bifacial module energy yield.

Consequently, the module selected for this application should be poly-crystalline, bi-facial, half-cell design. One of the typical PV modules Wood has used in their design recent project (June 2022) is provided in **Appendix B.**

3.1.2 DC electrical system

PV modules are connected in series forming a string rated up to 1500Vdc. Depending on system design parameters, local weather parameters, module specifications, a typical single string would consist of 24 to 27 PV modules connected in series for 1500Vdc class as the most common voltage. It is noteworthy that there are still 1000Vdc systems on the market but for utility scale solar projects they are rarely considered.

Groups of PV strings (roughly 16 to 20 strings) are connected to a common consolidating bus called DC combiner box. A group of combiner boxes are typically connected to a recombiner box or dedicated recombiner terminal bus at the solar inverter. As indicated in the Figure 4 below, DC feeds from combiner boxes are connected to the inverter common DC bus. Depending on solar farm DC zoning, the number of inputs can vary, typically from 20-28.

The Inverter loading ratio, also called DC-to-AC ratio, defines ratio of installed DC capacity (kWdc) to inverter AC output rating (kWac). To compensate for system losses (inverter, transformer, DC and AC cabling) the DC-to-AC ratio must be greater than 1.0. In previous projects Wood has utilized ratios ranging from 1.2 to 1.5. The higher the ratio, the higher the overall kWh yield, however the capital cost of the equipment (PV modules, cabling) will be also higher. Additionally, the power purchase agreement (PPA) and government solar incentive programs may limit the project DC overbuilt. For the estimate Wood has assumed a DC-to-AC ratio of 1.3.

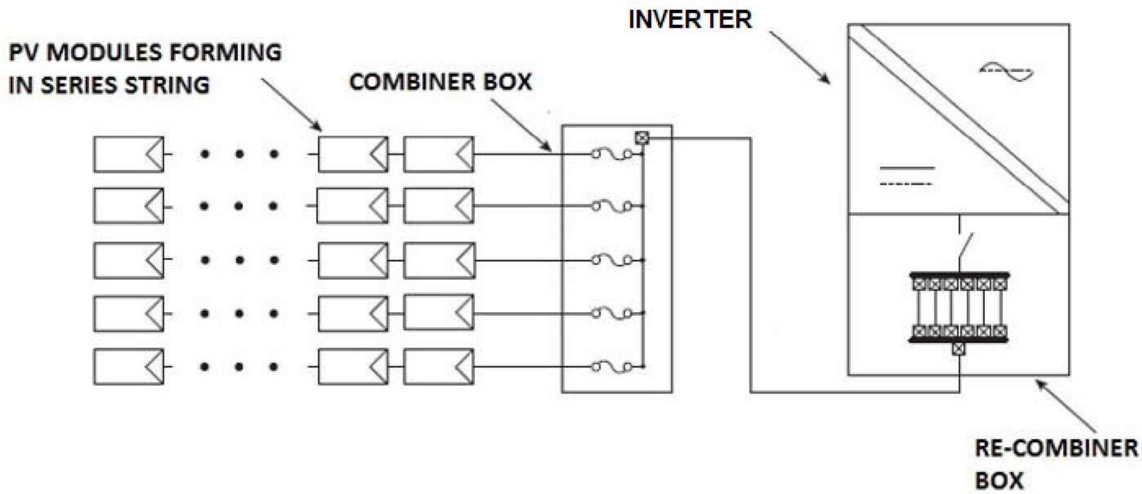


Figure 4: PV solar wiring design

DC string wiring is standardized as PV90 and RPVU90, 2kV class photovoltaic cable and is typically sized as #10 AWG Cu for strings and 350kcmil AL to #500kcmil AL for combiner to recombiner runs. Combiner boxes are relatively simple devices consisting of disconnect switch and finger-safe fuse holders for incoming strings and can be assembled in electrical shops as long as they can be CSA certified before installation (See Figure 5).

Figure 5: Combiner box

From Figure 4 above, a DC solar system will connect to the dedicated DC bus at the solar inverter. Considering that the sites will be rated at 10MWac and 20MWac, Wood recommends utility scale skid mounted inverter package. A typical package consists of DC/AC inverter(s) and MV step-up transformer connecting to MV collector system typically run at 25kV or 35 kV level. Based on our experiences, it is not a standard package to have an inverter station connected to voltages higher then 35 kV level.

Currently, Wood's design team is utilizing Sungrow 3600UD-MV unit, rated for a maximum 3600MVA however there are other credible vendors Wood has used in other projects such in past such as TMEIC and SMA. Refer to **Appendix A** for Sungrow unit specifications.

3.1.3 Solar racking system

There are three different racking configurations considered for ground mounted solar system:

a) fixed tilt arrangement
b) single axis tracker
c) dual axis tracker system

Fixed tilt arrangement is based on the most optimal fixed angle as determined by energy yield software (PVsyst or equivalent). Single axis tracker arrangement follows sun azimuth and oriented east-west for an additional yield and dual axis arrangement rotates both east-west and north-south for the maximum yield.

Most common arrangement in Canadian climate is fixed tilt and on some occasions single-axis tracker. It should be noted that tracker systems have moving parts and more potential for failure as our Canadian temperature ranges from extreme cold to extreme hot. Furthermore, weather elements such as freezing rain, snow accumulation may put additional burden and potential for premature failure to the racking structures.

3.2 Battery Energy Storage System (BESS)

Latest trends in solar system design considers BESS. This arrangement can be AC coupled where batteries are connected to a common MV bus at the substation. The other, more common option for a new project, is DC coupled with batteries connected directly to DC bus of the inverter. DC coupled system directly harvest excess energy production from PV system and discharge during no or low PV generation such as nighttime, dusk & dawn or a cloudy day. See Figure 6 below.

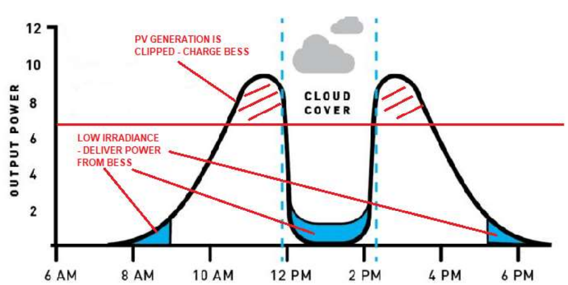


Figure 6: BESS Charging and discharging cycle

AC coupled systems are generally considered for existing solar farms where it is challenging to interface DC coupled system to an existing solar inverter but also where there is a need for grid support such as frequency response, voltage regulation and peak shaving.

For the energy arbitrage benefits, AC coupled systems do not provide the benefit of storing excess solar generation and storing clipped solar PV power as this is only possible with DC coupled systems.

Additionally, AC coupled systems are subject to an additional electrical transformation, from the DC to AC and again from the AC to DC, contributing to additional losses. For the purpose of this exercise, Wood recommends DC coupled systems.

It is necessary to perform a detailed analysis for actual BESS sizing, taking into account actual PV plant production, BESS augmentation, base capital costs and electricity rates. Wood assumptions for the size of the battery system is 100% of the actual solar farm MW rating with 4-hour reserve. Therefore, for a solar farm rated at 10MWac, BESS would be considered at 10MW/40MWh, or 20MW/80MWh for 20MWac solar farm.

3.3 Civil Engineering Considerations

Civil aspects can often be neglected when it comes to estimating of the civil works. Lack of geotechnical information at the early stages of the project may lead to wrong assumptions and minimize civil works scopes such as grading, grubbing and clearing. In general, 10% slope or less is recommended, so where sites are steep, additional grading may be required or sections of the land can be excluded from the layout. Elements such as the 50 year and 100 year flood plain can further reduce buildable area. Knowing type of the soil can impact the solar PV pile and racking design. Addressing actual available (buildable) area is critical as it drives the DC layout design and quantity of the PV modules which can be installed.

Minimum clearance from the waterways, residential areas and other environmental features (nesting areas, endangered species) will impact and may reduce actual construction area.

Based on previous experience, Wood assumes that approximately 5 acres is required for 1MW of solar PV installation. This also impacted by energy yield system modelling (using software tools such as PVsyst, Helioscope, Homer, etc.) which would dictate rack-to-rack spacing (pitch).

3.4 MV Collector System

Knowing that solar system would be connecting to 69kV bus at the terminal station, it would be recommended to connect solar collector system at 34.5kV level which is industry standard distribution voltage for the utility scale solar farms. Inverter station would be interconnected with 35kV, AL, 100% insulation, TRXLPE cable (c/w concentric neutral) cable. The cable size can range from 2/0 to 500kmil depending on circuit configuration and soil thermal characteristics. For larger solar farms, a 34.5kV single feeder (main home run) can carry in the range of 25MW to 30MW utilizing 1250kcmil cable. Depending on the solar farm layout configuration, 35kV, 600A class junction boxes may be required to connect sub-circuits.

3.5 Terminal Station Interconnection

At the existing MV terminal station (69kV), it will be necessary to step up from 34.5kV collector system voltage to the terminal station voltage. For the interconnection, it is required to interface with a new 69kV breaker along with 69KV voltage transformer (for relay protection purposes), main two stage fan cooled step-up transformer

(6/8/10MVA, 69kV-35kV) and 35kV pad mount switchgear with minimum two 35kV feeders c/w breaker protection. If required by NL Hydro, a separate metering structure can be considered on 69kV side of the project.

4. Cost and Schedule

4.1 Type of Estimate

This estimate is a Class 5 indicative estimate. This classification represents a rough order of magnitude estimate. It generally implies from -20% to 50% on the low side and +30% to up to 100% on the high side in accordance with AACE International Recommended Practices.

4.2 Project schedule

Project schedule is very important aspect in particular in today's volatile market because of longer lead time for equipment procurement. Addressing preliminary design at early stages and securing long lead items are critical for the overall project delivery. This in particular refers to: PV modules, racking & posts, inverter and BESS packages, 69kV substation equipment such as main transformer, PTs & breakers.

Utility scale solar is quite new in NL and availability of skilled resources and general labour may be limited. Construction activities shall ensure that all civil and electrical work occurs in spring to fall period. During winter months limited electrical work (such as LV wiring connections at protection building), commissioning activities and addressing minor deficiencies can occur.

Geotech field work must be performed as early as possible to enable the project team can to account for site conditions for racking system design and solar farm layout.

Solar project durations can range from approximately one year for accelerated commercial ventures to in excess of 2 years when pre-feed activities, permitting, project sanctioning, procurement of long lead items and construction season limitations are all taken into account. For an indicative project schedule please that takes these elements into consideration refer to **Appendix D**.

Following is a list of typical sequential project activities:

a) Permitting and approval process
b) Geotech field work
c) Base engineering (needed for key equipment procurement)
d) Equipment procurement
e) Detailed engineering
f) Construction
g) Testing and commissioning
h) Post construction activities (deficiencies, warranty items, etc.)

4.3 Cost Summary

10 MW Solar Farm		
	Engineering and Permitting	$960,000
	Solar Field	$11,645,000
	Terminal Station Upgrades (69 kV)	$3,101,000
	Contingency (10%)	$1,700,000
	Total Estimated Cost (Excl BESS)	$17,406,000
	BESS System	$1,380,000

20 MW Solar Farm		
	Engineering and Permitting	$1,080,000
	Solar Field	$23,290,000
	Terminal Station Upgrades (69 kV)	$4,312,,000
	Contingency (10%)	$3,100,000
	Total Estimated Cost (Excl BESS)	$31,782,000
	BESS System	$2,760,000

For detailed breakdown for both 10MWac solar farm + BESS and 20MWac solar farm + BESS please refer to **Appendix C**.

APPENDICES

Appendix A

Inverter Package including BESS

SG3425UD-MV/ SG3600UD-MV

SUNGROW
Clean power for all

Turnkey Station for North America 1500 Vdc System - MV Transformer Integrated

HIGH YIELD

- Advanced three-level technology, max. efficiency 98.9%
- Full power operation at 45 ℃ (113 ℉)
- Effective cooling, wide operation temperature
- Max. DC/AC ratio up to 2.0

SMART O&M

- Integrated current, voltage and MV parameters monitoring function for online analysis and trouble shooting
- Modular design, easy for maintenance

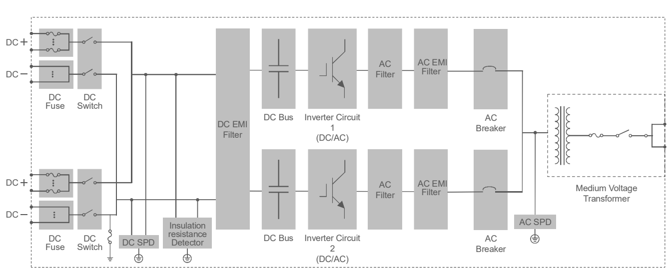
SAVED INVESTMENT

- Low transportation and installation cost due to 20-foot container size design
- DC-coupled storage interface and charging power from the grid, low system cost
- Integrated MV transformer and LV auxiliary power supply
- Q at night optional

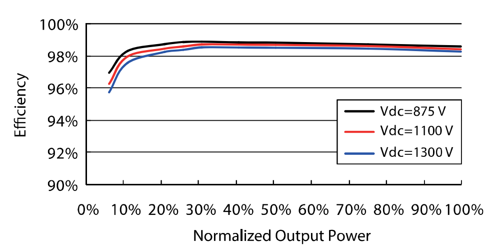
GRID SUPPORT

- Compliance with standards:UL 1741,UL 1741 SA, IEEE 1547, Rule 21 and NEC code
- Low / High voltage ride through (L/HVRT), L/HFRT, soft start/stop
- Active & reactive power control and power ramp rate control

CIRCUIT DIAGRAM



EFFICIENCY CURVE (SG3425UD)



SG3425UD-MV/SG3600UD-MV

Type designation	SG3425UD-MV	SG3600UD-MV
Input (DC)		
Max. PV input voltage	1500 V	
Min. PV input voltage / Startup input voltage	875 V / 915 V	915 V / 955 V
Available DC fuse sizes	250A, 315A, 400A, 450A, 500A	
MPP voltage range	875 – 1300 V	915 – 1300 V
No. of independent MPP inputs	1	
No. of DC inputs	20 (optional: 22 / 24 / 26 / 28)	
Max. DC short-circuit current	10000 A	
PV array configuration	Negative grounding or floating	
Output (AC)		
AC output power	3425 kVA @ 45 ℃ (113 ℉), 3083 kVA @ 50 ℃ (122 ℉)	3600 kVA @ 45 ℃ (113 ℉), 3240 kVA @ 50 ℃ (122 ℉)
Nominal grid frequency / Grid frequency range	50 Hz / 45 – 55 Hz, 60 Hz / 50 – 65 Hz	
Harmonic (THD)	< 3 % (at nominal power)	
Power factor at nominal power / Ajustable power factor	> 0.99 / 0.8 leading - 0.8 lagging	
Efficiency		
Inverter Max. efficiency	98.9 %	
Inverter CEC efficiency	98.5 %	
Transformer		
Transformer rated power	3425 kVA	3600 kVA
Transformer max. power	3425 kVA	3600 kVA
LV / MV voltage	0.6 kV / (12 – 35) kV	0.63 kV / (12 – 35) kV
Transformer vector	Dy1 or Dy11	
Transformer cooling type	ONAN (Optional: KNAN)	
Protection		
DC input protection	Load break switch + fuse	
Inverter output protection	Circuit breaker	
AC MV output protection	Load break switch + fuse	
Overvoltage protection	DC Type II / AC Type II	
Grid monitoring / Ground fault monitoring	Yes / Yes	
Insulation monitoring	Yes	
Overheat protection	Yes	
General Data		
Dimensions (W*H*D)	6058 * 2896 * 2438 mm 238.5'' * 114.0'' * 96.0''	
Weight	18000 kg 39683.2 lbs	
Degree of protection	NEMA 4X(Electronic for Inverter) / NEMA 3R(Others)	
Auxiliary power supply	5kVA, 120Vac/240Vac; Optional: 30kVA, 480Vac/277Vac	
Operating ambient temperature range	-35 to 60 ℃ (> 45 ℃ derating) / optional: -40 to 60 ℃ (> 45 ℃ derating) -22 to 140 ℉ (> 113 ℉ derating) / optional: -40 to 140 ℉ (> 113 ℉ derating)	
Allowable relative humidity range	0 - 100 %	
Cooling method	Temperature controlled forced air cooling	
Max. operating altitude	1000 m (Standard) / > 1000 m (Customized) (3280.8 ft (standard) / > 3280.8 ft (Customized))	
DC-coupled storage interface	Optional	
Charging power from the grid	Optional	
Communication	Standard: RS485, Ethernet; Optional: optical fiber	
Compliance	UL 1741, IEEE 1547, UL1741 SA, NEC 2017, CSA C22.2 No.107.1-01	
Grid support	Q at night function (optional), L/HVRT, L/HFRT, Active & reactive power control and power ramp rate control, Volt-var, Frequency-watt	

280Ah Cell Datasheet

Datasheet

SUNGROW

Version 1.0 EN

Version Record

Version	Revision time	Revision Content	Reviser	Reviewer
V1.0	2020.04.29	Initial version	PXY	
V1.1	2020.06.09	Modify Eff., Weight etc.	PXY	

1. Overview

This document describes the Cell Parameters of CATL (280Ah).

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2. Cell Datasheet

NO.	Classification	Specification	Remarks
1.	image		
2.	Type of Battery	LFP	/
3.	Nominal Voltage (V)	3.2	/
4.	Nominal Capacity (Ah)	280	/
5.	C-rate (C)	≤1	/
6.	Voltage Range (V)	2.5-3.65	25℃

7.	Cycles	7500	@25℃,100%DOD%,EOL70%,1C/1C
8.	Energy efficiency	≥92.2%	@25℃，1C/1C （Discharging energy）/（Charging energy）
9.	Dimension（W×D×H mm）	173.9×71.7×207.2	/
10.	Weight（Kg）	5.46	/
11.	Storage Temperature Range（℃）	-30-60	/
12.	Operating Temperature Range（℃）	0-55 (Charging) -30-55 (Discharging)	/

SUNGROW
Clean power for all

LFP Li-ion Battery System New

Over 1 hour

EFFICIENT & HIGH YIELD

- 20-year service life, 8000+ times system-level cycle life
- Support 1500V system, reduce AC side loss by 60%
- Deep charge & discharge design, initial investment saves more than 5%

INTELLIGENT & FRIENDLY

- 40-foot container can hold 4.4MWh, compatible downwards
- Oneline estimation of SOC & SOH based on scenes and big data
- Support cloud platform, remote real-time monitoring and fault identification

SAFE & RELIABLE

- Two-level short-circuit protection, graded fast current limiting
- Fool-proof, anti-reverse connection design, safer installation and maintenance
- Patented air duct and intelligent air cooling design, temperature difference < 3℃
- Meet global high standard authoritative certification requirements

Item	Specification
Model	M2L-M143
Charge&discharge rate	≤ 1C
Cell type	LFP 280Ah
Configuration	1P16S
Capacity	280 Ah
Nominal energy	14.3 kWh
Charging&discharging power	≤ 14.3 kW
Nominal voltage	51.2 V
Operating voltage range	43.2 V–58.4 V
Dimensions (W*H*D)	455*230*760mm
Weight	105 kg

Item	Specification
Model	M2L-R372
Charge&discharge rate	≤ 1C
Cell type	LFP 280Ah
Configuration	1P416S
Key component	PACK*26+SG*1
Capacity	280 Ah
Nominal energy	372,7 kWh
Charging&discharging power	≤ 372.7 kW
Nominal voltage	1331.2 V
Operating voltage range	1123.2V–1497.6 V
Dimensions (W*H*D)	1500*2285*760 mm

Switchgear Cabinet Datasheet

Datasheet

SUNGROW

Version 1.0 EN

Version Record

Version	Revision time	Revision Content	Reviser	Reviewer
V1.0	2020.04.29	Initial version	PXY	

1. Overview

This document describes the Switchgear Cabinet Datasheet of CATL (280Ah).

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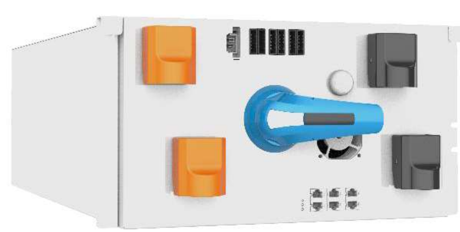
2. Switchgear Cabinet Datasheet

Classification	Specification
Image	
Model	M2L-S280H
Key Component	Control BMS unit 1ea Relay 2ea Fuse 2ea Current sensor 2ea Load switch 1ea
Dimension W x H x D	16.1"×9.0"×29.9"
Auxiliary Power	24V

Pack to Rack communication	UART
Rack to System communication	CAN 2.0B
Voltage Accuracy	±5V
Current Accuracy	0.2%FSR

SUNGROW

SD1250HV Preliminary

DC/DC Converter

HIGH YIELD

- Max efficiency 99%
- Wide DC input voltage range, flexible for battery configuration
- Modular design, compatible with rack level battery management

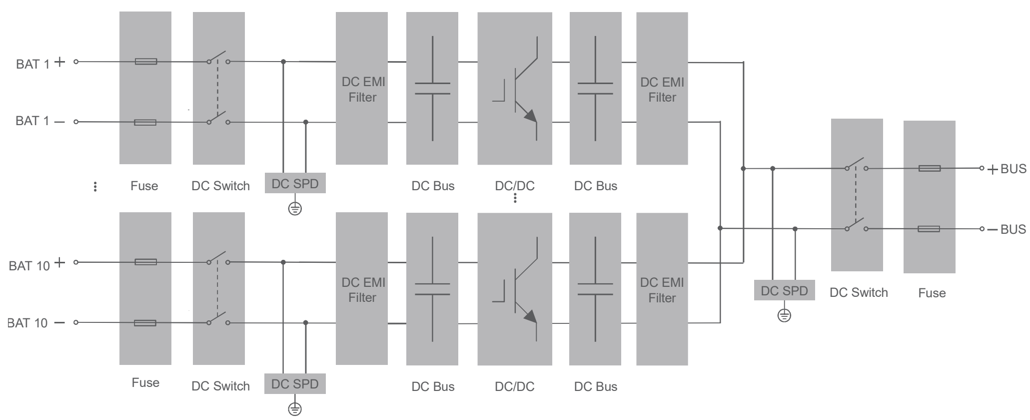
EASY O&M

- High protection degree (IP65/NEMA 4X, C5)
- Compact design and light weight for easy installation

FLEXIBLE APPLICATION

- Bidirectional buck-boost design for better voltage matching
- Compatible with 1500V battery system
- MPPT function integrated, compatible with DC microgrid applications

CIRCUIT DIAGRAM



Type Designation	SD1250HV
Power Rating	
Nominal power	1250 kW
Max. power	1690 kW
Battery Side	
Max. DC voltage	1500 V
DC operating voltage range	0 – 1500V
Max. DC current	140 A * 10
BUS Side	
Max. DC voltage	1500 V
DC operating voltage range	500 – 1500 V
Max. DC current	1400 A
Efficiency	
Max efficiency	99.0%
Protection	
Reverse polarity protection	Yes
Overvoltage protection	Type II
Insulation monitoring	Yes
Overheat protection	Yes
General Data	
Dimensions (W*H*D)	2150 * 2150 * 850 mm 84.6" * 84.6" * 33.5"
Weight	1200 kg 2645.5 lbs
Degree of protection	IP 65 NEMA 4X
Operating ambient temperature range	-30 to 60 ℃ -22 to 140 ℉
Allowable relative humidity range (non-condensing)	0 – 100 %
Cooling concept	Temperature-controlled forced air cooling
Max. operating altitude	4,000m(> 3,000 m derating) 13123 ft (> 9,843 ft derating)
Display	LED, Bluetooth + APP
Communication	RS485, Ethernet, CAN
Compliance	CE, IEC 62109-1, UL 1741

SUNGROW

SD125HV

Preliminary

DC/DC Converter

HIGH YIELD

- Max efficiency 99%
- Wide DC input voltage range, flexible for battery configuration
- Modular design, compatible with rack level battery management

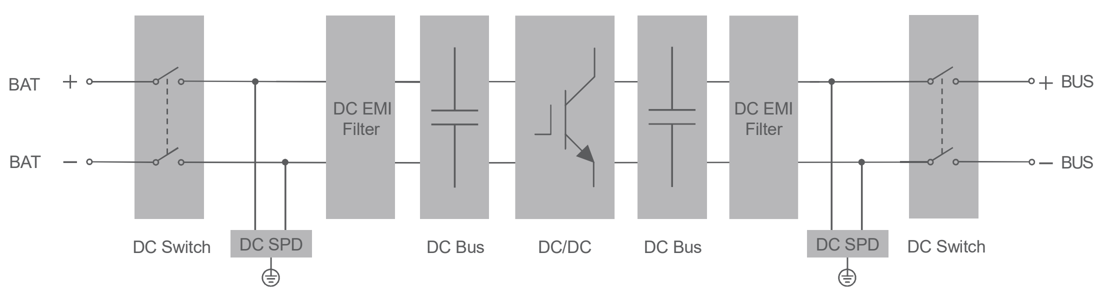
EASY O&M

- High protection degree(IP65/NEMA 4X, C5)
- Compact design and light weight for easy installation
- Easy site commissioning & monitoring via APP

FLEXIBLE APPLICATION

- Bidirectional buck-boost design for better voltage matching
- Compatible with 1500V battery system
- MPPT function integrated, compatible with DC microgrid applications

CIRCUIT DIAGRAM



Type Designation	SD125HV
Power Rating	
Nominal power	125 kW
Max. power	169 kW
Battery Side	
Max. DC voltage	1500 V
DC operating voltage range	0 – 1500V
Max. DC current	140 A
BUS Side	
Max. DC voltage	1500 V
DC operating voltage range	500 – 1500 V
Max. DC current	140 A
Efficiency	
Max efficiency	99.0%
Protection	
Reverse polarity protection	Yes
Overvoltage protection	Type II
Insulation monitoring	Yes
Overheat protection	Yes
General Data	
Dimensions (W*H*D)	650 * 650 * 300 mm 25.6" * 25.6" * 11.8"
Weight	60 kg 132.3 lbs
Degree of protection	IP 65 NEMA 4X
Operating ambient temperature range	-30 to 60 ℃ -22 to 140 ℉
Allowable relative humidity range (non-condensing)	0 – 100 %
Cooling concept	Temperature-controlled forced air cooling
Max. operating altitude	4,000m(> 3,000 m derating) 13123 ft (> 9,843 ft derating)
Display	LED, Bluetooth + APP
Communication	RS485, Ethernet, CAN
Compliance	CE, IEC 62109-1, UL 1741

Appendix B

PV module specifications

Hi-MO 5

LR5-72HBD
520~545M

- Based on M10-182mm wafer, best choice for ultra-large power plants
- Advanced module technology delivers superior module efficiency
  - M10 Gallium-doped Wafer • Smart Soldering • 9-busbar Half-cut Cell
- Globally validated bifacial energy yield
- High module quality ensures long-term reliability

12 — 12-year Warranty for Materials and Processing

30 — 30-year Warranty for Extra Linear Power Output

Complete System and Product Certifications

IEC 61215, IEC 61730, UL 61730
ISO 9001:2008: ISO Quality Management System
ISO 14001: 2004: ISO Environment Management System
TS62941: Guideline for module design qualification and type approval
OHSAS 18001: 2007 Occupational Health and Safety

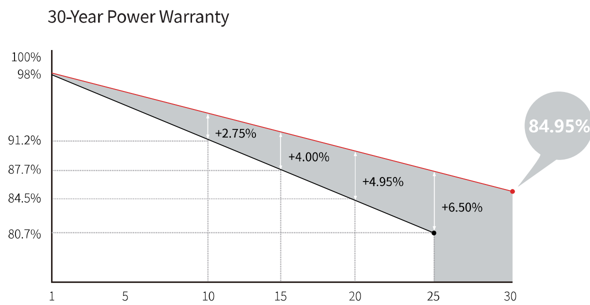
LONGi

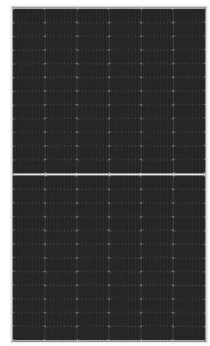
Hi-MO 5

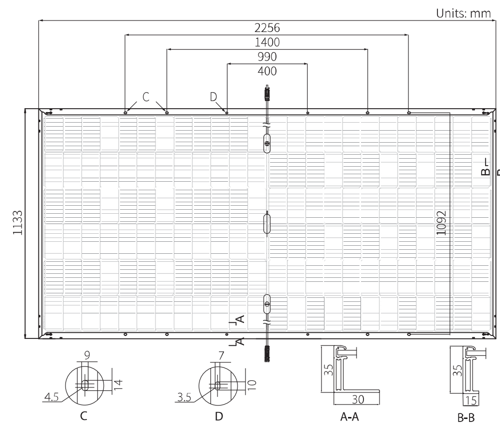
LR5-72HBD 520~545M

21.3%	0~+5W	<2%	0.45%	HALF-CELL
MAX MODULE EFFICIENCY	POWER TOLERANCE	FIRST YEAR POWER DEGRADATION	YEAR 2-30 POWER DEGRADATION	Lower operating temperature

Additional Value







Mechanical Parameters

Cell Orientation	144 (6×24)
Junction Box	IP68, three diodes
Output Cable	4mm², positive 400 / negative 200mm length can be customized
Glass	Dual glass, 2.0mm coated tempered glass
Frame	Anodized aluminum alloy frame
Weight	32.3kg
Dimension	2256×1133×35mm
Packaging	31pcs per pallet / 155pcs per 20' GP / 620pcs per 40' HC

Electrical Characteristics
STC : AM1.5 1000W/m² 25°C Test uncertainty for Pmax: ±3%

Power Class	520	525	530	535	540	545
Maximum Power (Pmax/W)	520	525	530	535	540	545
Open Circuit Voltage (Voc/V)	48.90	49.05	49.20	49.35	49.50	49.65
Short Circuit Current (Isc/A)	13.57	13.65	13.71	13.78	13.85	13.92
Voltage at Maximum Power (Vmp/V)	41.05	41.20	41.35	41.50	41.65	41.80
Current at Maximum Power (Imp/A)	12.67	12.75	12.82	12.90	12.97	13.04
Module Efficiency(%)	20.3	20.5	20.7	20.9	21.1	21.3

Operating Parameters

Operational Temperature	-40°C ~ +85°C
Power Output Tolerance	0 ~ +5 W
Voc and Isc Tolerance	±3%
Maximum System Voltage	DC1500V (IEC/UL)
Maximum Series Fuse Rating	30A
Nominal Operating Cell Temperature	45±2°C
Protection Class	Class II
Fire Rating	UL type 29
Bifaciality	70±5%

Mechanical Loading

Front Side Maximum Static Loading	5400Pa
Rear Side Maximum Static Loading	2400Pa
Hailstone Test	25mm Hailstone at the speed of 23m/s

Temperature Ratings (STC)

Temperature Coefficient of Isc	+0.050%/°C
Temperature Coefficient of Voc	-0.284%/°C
Temperature Coefficient of Pmax	-0.350%/°C

LONGi

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826, Pudong Shanghai, China
Tel: +86-21-80162606
Web: en.longi-solar.com

Appendix C

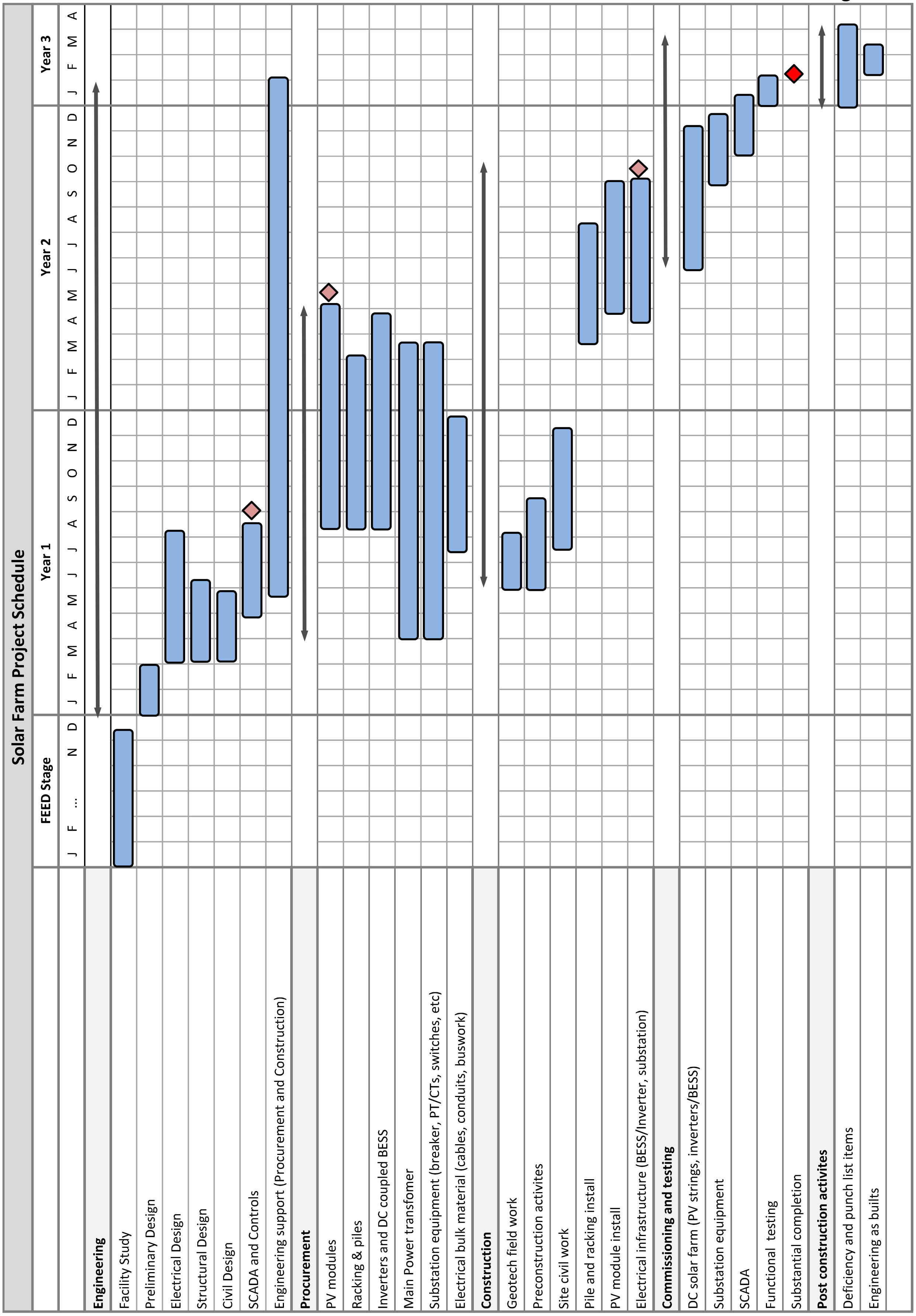
Cost Summary

Class 5 Solar farm Estimate	10MWac solar farm + BESS				
DC/AC ratio	1.3				
Module type	Longi, LR5-72W, 545W				
Size (MWac)	10				
Size (MWdc)	13				
Number of Modules	23,853				
Development Activities		***Description***	***PU cost ($ CAD)***	***Total***	***Comments***
Engineering and Permitting					
1	Interconnection Studies		1	$50,000	
2	Environmental Assessments		1	$50,000	
3	Permits and licenses		1	$50,000	
4	Site surveys		1	$50,000	
5	Geotech		1	$40,000	
5	Detailed Engineering		1	$480,000	Assumes 4000 hours with an average rate of $120/hour. Includes construction support.
6	Site management (site mtg, cost controller, safety)		2	$160,000	
7	Owner Engineer Role		1	$80,000	Includes drawing reviews and approvals and occasional site visit
	Subtotal - Engineering and Permitting			**$960,000**	
Solar Field					**Installed costs**
1	PV module	Longi LR5-72HBD 545W	0.45	$5,850,000	Cost of PV assumed to be $0.45/Watt based on previous project quotes
2	Inverters package	Sungrow 3600UD-MV	3	$660,000	Quote from vendor (prorated for this project)
3	Solar AC and DC supply & installation		0.1	$1,300,000	Includes DC harnesses, combiner boxes, AC cabling. Factor reference from another project
4	SCADA and fiber		0.01	$130,000	Factor reference from another project
5	Solar posts & racking		0.18	$2,340,000	$0.13/W. Cost reference from another project as per vendor quote
6	Post, PV module and rack installation		0.05	$650,000	Cost reference from another project.
7	Civil Works		0.05	$650,000	Includes site clearing, solar farm service roads, grubbing
8	DC system commissioning		0.005	$65,000	Cost reference from another project.
	Subtotal - Solar Field			**$11,645,000**	
Terminal area (69kV)					**Installed costs**
1	Main step up transformer			$600,000	Northern Transformer reference, 10MW (6/8/10MVA) 2 stage fan cooled, 35kV-69kV,
2	69kV Motorized Disconnect Switch			$25,000	Cost reference from another project.
3	MV Surge arresters			$15,000	Cost reference from another project.
4	69kV circuit breaker			$250,000	Cost reference from another project.
5	69kV Revenue Metering			$150,000	Cost reference from another project.
6	Additions to existing protection and control building			$200,000	Protection relays & racking, LV DC/AC wiring, power plant controller. It is assumed that new protection equipment will fit within existing P&C building
7	SCADA and solar plant controller			$150,000	SCADA equipment added to the existing P&C building
8	69kV support steel structures			$300,000	
9	Upgrade to station service transformer			$25,000	
10	35kV pad mount switchgear			$95,000	Reference to vendor quote (G&W)
11	Substation Civil works and foundation			$160,000	Internal references (includes foundation for main transformer, MV breaker, pad mount switchgear and support structures)
12	Substation testing and commissioning		0.007	$91,000	
13	Indirect Costs		0.08	$1,040,000	Equipment rentals, tools, etc. Cost reference from another project.
	Subtotal - Terminal Area			**$3,101,000**	
	Contingency		**0.1**	**$1,700,000**	Assumes 10% (reference from another project)
	TOTAL			**$17,406,000**	
	BESS system				
1	DC BESS	Sungrow 3.3MW/10MWh	3	$525,000	Quote from vendor (prorated for this project)
2	BESS 40 foot container	Sungrow	3	$525,000	Quote from vendor (prorated for this project)
3	BESS and inverter foundations			$330,000	
	TOTAL			**$1,380,000**	

Class 5 Solar farm Estimate	20MWac solar farm + BESS				
DC/AC ratio	1.3				
Module type	Longi, LR5-72W, 545W				
Size (MWac)	20				
Size (MWdc)	26				
Number of Modules	47,706				
Development Activities		***Description***	***PU cost ($ CAD)***	***Total***	***Comments***
Engineering and Permitting					
1	Interconnection Studies		1	$50,000	
2	Environmental Assessments		1	$50,000	
3	Permits and licenses		1	$50,000	
4	Site surveys		1	$50,000	
5	Geotech		1	$40,000	
5	Detailed Engineering		1	$600,000	Assumes 5000 hours with an average rate of $120/hour. Includes construction support and occasional site visit
6	Site management (site mtg, cost controller, safety)		2	$160,000	
7	Owner Engineer Role		1	$80,000	Includes drawing review and approval, occasional site visit
	Subtotal - Engineering and Permitting			**$1,080,000**	
Solar Field					**Installed costs**
1	PV module	Longi LR5-72HBD 545W	0.45	$11,700,000	Cost of PV assumed to be $0.45/Watt based on previous project quotes
2	Inverters package	Sungrow 3600UD-MV	6	$1,320,000	Quote from vendor (prorated for this project)
3	Solar AC and DC supply & installation		0.1	$2,600,000	Includes DC harnesses, combiner boxes, AC cabling. Factor reference from another project
4	SCADA and fiber		0.01	$260,000	Factor reference from another project
5	Solar posts & racking		0.18	$4,680,000	$0.13/W. Cost reference from another project as per vendor quote
6	Post, PV module and rack installation		0.05	$1,300,000	Cost reference from another project.
7	Civil Works		0.05	$1,300,000	Includes site clearing, solar farm service roads, grubbing
8	DC system commissioning		0.005	$130,000	Cost reference from another project.
	Subtotal - Solar Field			**$23,290,000**	
Terminal area (69kV)					**Installed costs**
1	Main step up transformer			$600,000	Northern Transformer reference, 10MW (6/8/10MVA) 2 stage fan cooled, 35kV-69kV
2	69kV Motorized Disconnect Switch			$25,000	Cost reference from another project.
3	MV Surge arresters			$15,000	Cost reference from another project.
4	69kV circuit breaker			$250,000	Cost reference from another project.
5	69kV PT (for protection)			$80,000	Cost reference from another project.
6	69kV Revenue Metering			$150,000	Cost reference from another project.
7	Additions to existing protection and control building			$200,000	Protection relays & racking, LV DC/AC wiring, power plant controller. It is assumed that new protection equipment will fit within existing P&C building
8	SCADA and solar plant controller			$150,000	SCADA equipment added to the existing P&C building
9	69kV support steel structures			$300,000	
10	Upgrade to station service transformer			$25,000	
11	35kV pad mount switchgear			$95,000	Reference to vendor quote (G&W)
12	Substation Civil works and foundation			$160,000	Internal references (includes foundation for main transformer, MV breaker, pad mount switchgear and support structures)
13	Substation testing and commissioning		0.007	$182,000	
14	Indirect Costs		0.08	$2,080,000	Equipment rentals, tools, etc. Cost reference from another project.
	Subtotal - Terminal Area			**$4,312,000**	
15	**Contingency**		**0.1**	**$3,100,000**	Assumes 10% (reference from another project)
	TOTAL			**$31,782,000**	
	BESS system				
1	DC BESS	Sungrow 3.3MW/10MWh	6	$1,050,000	Quote from vendor (prorated for this project)
2	BESS 40 foot container	Sungrow	6	$1,050,000	Quote from vendor (prorated for this project)
3	BESS and inverter foundations			$660,000	
	TOTAL			**$2,760,000**	

Appendix D

Project Schedule


Solar Farm Project Schedule
FEED Stage
Year 1
Year 2
Year 3
J F … N D
J F M A M J J A S O N D
J F M A M J J A S O N D
J F M A
Engineering
Facility Study
Preliminary Design
Electrical Design
Structural Design
Civil Design
SCADA and Controls
Engineering support (Procurement and Construction)
Procurement
PV modules
Racking & piles
Inverters and DC coupled BESS
Main Power transfomer
Substation equipment (breaker, PT/CTs, switches, etc)
Electrical bulk material (cables, conduits, buswork)
Construction
Geotech field work
Preconstruction activites
Site civil work
Pile and racking install
PV module install
Electrical infrastructure (BESS/Inverter, substation)
Commissioning and testing
DC solar farm (PV strings, inverters/BESS)
Substation equipment
SCADA
Functional testing
Substantial completion
Post construction activites
Deficiency and punch list items
Engineering as builts

BESS Project Preliminary Cost Estimate

254388-0000-DF00-STY-0002

August 22, 2022

Wood Canada Limited
600–2020 Winston Park Drive
Oakville, ON L6H 6X7

wood.

APPROVALS

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Professional Stamp

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Wood Canada Limited
02020
Signature or Member Number (Member-in-Responsible Charge)

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REVISION HISTORY

Rev.	Description	Prepared By	Checked By	Approved By	Date
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1. Introduction

Newfoundland and Labrador (NL) Hydro is looking for an opportunity to introduce AC coupled Battery Energy Storage System (BESS) into their existing infrastructure. The specific location of the system has not yet been determined, however the site is expected to be near Avalon Peninsula connected to an existing terminal station on a 69/66kV bus.

2. Purpose and Scope

The purpose of the report is to provide an indicative (Class 5) cost estimate for an 20MWac and 50MWac BESS system with 4-hour reserve. The BESS would be connected to the existing terminal station at 66kV/69kV bus. This estimate includes relevant MV substation interconnection components needed to integrate with the existing terminal stations. For the purpose of this estimate, 69kV voltage level shall be considered.

Wood has made assumptions based on industry standards and previous experiences with AC coupled BESS, as follows:

- MV collector system design including substation requirements
- Project scheduling and major project milestones
- Developmental activities such as field investigation (ex. Geotech report), desktop studies, permitting, preliminary & detailed engineering, environmental studies, licenses, etc.
- Major equipment costs
- Supporting activities during the construction stage (Site management & monitoring, owner engineer costs, safety, equipment rental, etc.)
- Construction cost for both BESS and upgrades at the existing 69kV terminal station

3. System Characteristics

This section describes technologies and technical characterises of the major components for AC coupled BESS package, MV collector system including associated cabling, substation components required at the terminal station (such as main power transformer, breaker, disconnect switch, protection and metering).

3.1 Battery Energy Storage System (BESS)

The proposed BESS solution is AC coupled, where batteries are connected to a common MV bus at the substation. The system can store energy from any generation source with main purpose being to discharge during peak electricity use. Peak shaving concept is depicted on **Figure 1** below.

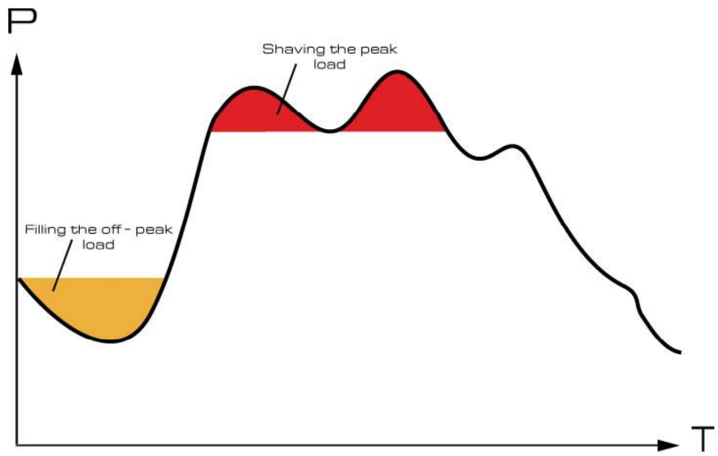


Figure 1: Peak shaving concept

AC coupled systems are generally considered for existing electrical infrastructure as they are easier to retrofit when compared to DC coupled solutions (typical for new solar PV installations). The drawback with AC coupled systems is the additional power conversion, from generating source to BESS and then from BESS to AC grid, resulting in additional efficiency losses. The typical industry standard for BESS lifespan is 20 years and standard warranties are 3 years. Extended warranties up to 20 years can be procured, however pricing for this was not available for this study..

3.2 Civil Engineering Considerations

Preliminary design approach needs to ensure that there is adequate area for BESS equipment. A typical BESS is housed in container with approximate dimensions: 12m (L) x 3m (W) x 3.5m (H), however every vendor provides different MW/MWh capacity per container and as a result physical sizes will vary. Wood assumes 3MW/12MWh for a typical container with dimension as noted above.

a) Option 1: 20MW, 4 hours reserve system would require 7 containers
b) Option 2: 50 MW, 4 hours reserve system would require 17 containers

To allow for clearance and location for AC MV connections (MV transformers, cabling, etc.), additional 2.5m around each side of the BESS container is assumed. The arrangement will require following area:

a) Option 1: 7 containers x [12m x (3m + 2.5m + 2.5m)] + 20% contingency = 806 m²
b) Option 2: 17 containers x [12m x (3m + 2.5m + 2.5m)] + 20% contingency = 1958 m²

Figure 2: BESS Layout

3.3 MV collector system

Wood recommends to have BESS system stepped up at 34.5kV level which is industry standard distribution voltage for the collector system in renewable sector; further this will be stepped up to 69kV level at the terminal station.

A typical BESS package will consist of a DC battery pack, DC-AC inverter, and 34.5kV step-up transformer connecting to point of common coupling (PCC) as per **Figure 3** below.

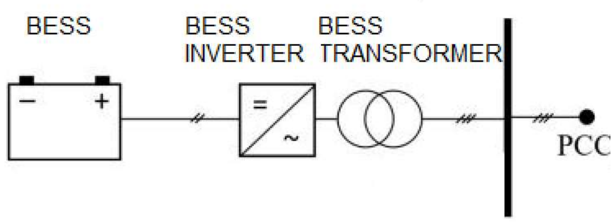


Figure 3: BESS SLD

As indicated above Wood assumed 3MW/12MWh BESS block. Units will be daisy chained and connected to a dedicated 34.5kV switchgear at the terminals station as per sample single line noted in **Figure 4**. Depending on the size of the BESS system, additional feeder breakers may be required. Further, design philosophy may dictate less BESS blocks in a circuit to ensure redundancy in case of trip or maintenance. With this approach, other blocks connected in a separate 34.5kV circuit can perform without interruption.

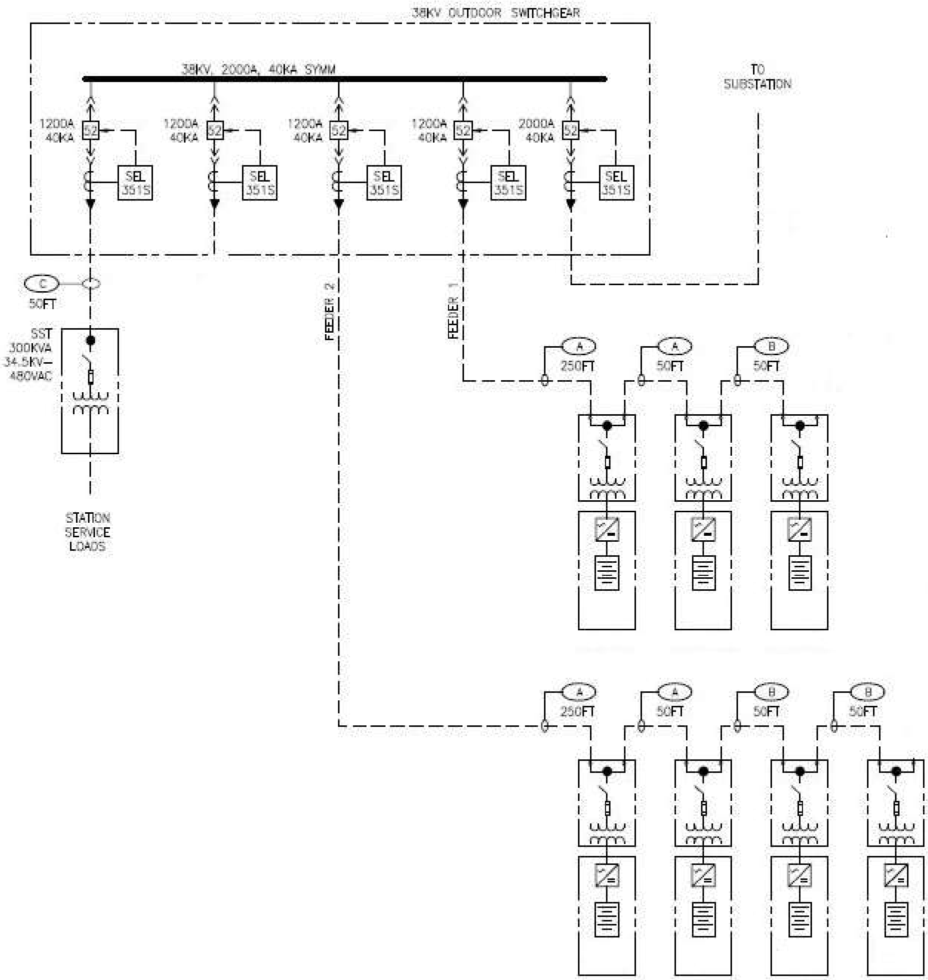


Figure 4: BESS AC arrangement

In addition to 34.5kV distribution, each BESS container will require external power supply for auxiliary loads (HVAC, controls, small power, etc.) and fiber optic connection to SCADA system.

3.4 Terminal Station interconnection

At the existing MV terminal station (69kV), it would be necessary to step up from 34.5kV switchgear to the terminal station voltage. For the interconnection, it will be necessary to interface with new 69kV breaker along with 69KV voltage transformer (for relay protection purposes), HV metering structure and main two stage fan cooled step-up transformer as follows:

- Option 1: 12/16/20MVA, 69kV-35kV
- Option 2: 30/40/50MVA, 69kV-35kV

4. Cost and Schedule

4.1 Type of Estimate

This estimate is a Class 5 indicative estimate. This classification represents a rough order of magnitude estimate. It generally implies from -20% to 50% on the low side and +30% to up to 100% on the high side in accordance with AACE International Recommended Practices.

4.2 Project schedule

Project schedule is very important aspect in particular in today's volatile market and much longer lead time for equipment procurement. Addressing preliminary design at early stages and securing long lead items are critical for the overall project delivery. This in particular refers to: BESS packages, 69kV substation equipment such as main transformer, PTs & breakers.

Utility scale BESS are new in NL and availability of skilled resources and general labour may be limited. Construction activities shall ensure that all civil and electrical work occurs in spring to fall period. During winter months limited electrical work (such as LV wiring connections at protection building), commissioning activities and addressing minor deficiencies can occur.

Geotech field work must be performed as soon as possible so the project team can understand the proposed land features in order to plan for proper foundation design for BESS. For indicative project schedule please refer to **Appendix C**.

Project durations for BESS installations can range from approximately one year for accelerated commercial ventures to in excess of 2 years when pre-feed activities, permitting, project sanctioning, procurement of long lead items and construction season limitations are all taken into account. For an indicative project schedule please that takes these elements into consideration refer to **Appendix D**.

Following is a list of typical sequential project activities:

a) Permitting and approval process
b) Geotech field work
c) Base engineering (needed for key equipment procurement)
d) Equipment procurement
e) Detailed engineering
f) Construction
g) Testing and commissioning
h) Post construction activities (deficiencies, warranty items, etc.)

4.3 Cost Summary

20 MW BESS (4hr @ 20 MW / 80 MWh)		
	Engineering and Permitting	$940,000
	BESS Area	$30,975,000
	Terminal Station Upgrades (69 kV)	$2,675,000
	Contingency (10%)	$3,500,000
	Total Estimated Cost	$37,910,000

50 MW BESS (4hr @ 50 MW / 200 MWh)		
	Engineering and Permitting	$1,080,000
	BESS Area	$74,582,000
	Terminal Station Upgrades (69 kV)	$3,190,000
	Contingency (10%)	$7,500,000
	Total Estimated Cost	$86,312,000

For detailed breakdown for both 20MW/80MWh and 50MW/200MWh BESS please refer to **Appendix B**.

APPENDICES

Appendix A

AC Coupled BESS package

Customer:	John Wood Group PLC	SunGrid Solutions	
Name:	Igor Bozic	135 George St. N	
Contact:	Igor.bozic@woodplc.com	Cambridge, ON, N1S 2M6	
		www.sungridsolutions.com	
Project:	BESS in NL	Contact:	Jacky Jiang
Prj. #:	570		jacky.jiang@sungridsolutions.com
Quote #:	01		647-865-5624
Size:	23MW, 85MWh / 52MW, 210MWh	Date:	30-Jun-22
Delivery:	Newfoundland and Labrador	Valid:	30 Days

SunGrid Indicative Pricing			**Notes**
	23MW, 85MWh	**52MW, 210MWh**	
Description	**Total Price**	**Total Price**	Dischargeble Energy = 85MWh DC and 210MWh DC at Year 0
Integration Engineering Services	$ 624,000	$ 1,192,000	
Interconnection (support only)	TBD	TBD	
Permits (support only)	TBD	TBD	
Equipment			- Delivery Date: TBD
Battery Cabinet	Included	Included	
-Batteries, Enclosures, HVAC, FSS, DC combiner	Included	Included	Payment Terms
-PCS	Included	Included	- 30% Purchase Order
MV Transformer	Included	Included	- 30% Mfg Start - 30% Delivery
EMS (Fractal or customer preference)	Included	Included	- 10% Commissioning
MV Switchgear, Pole Mounted Disconnects, Pole Run, Protection, Minor Equopment, etc.	Included	Included	
Shipping Logistics	Included	Included	
Total Equipment	**$ 24,686,000**	**$ 60,807,000**	
Construction/Install			
Civil(Fencing, Foundations, Piles, Vaults etc.)	Included	Included	
Civil Site Works/ Install	Included	Included	
Mechanical Installation	Included	Included	
Electrical install (all terminations)	Included	Included	
Total Construction/Install	**$ 5,085,000**	**$ 11,173,000**	
Commissioning	Included	Included	
Sales Tax	Not Included	Not Included	
Warranty and Performance Guarantee			
3-year workmanship	Included	Included	
Total	**$ 30,395,000**	**$ 73,882,000**	

Clarifications

- Import duties and sales tax not included
- Assumed clear site/road access to BESS
- Non-unionized labour
- Transfer trip not included
- POI located within BESS site
- Permit fees, application fees, etc. not included (support only)
- Final Interconnection not included
- Water well or city water or city sewer connection
- Hazardous and or contaminated material removal, investigation, abatement or removals not included
- Utility fees and/or interconnection costs not included
- Charge/Discharge signal/algorithm not included, Provided by Others
- Internet connection provided to BESS by others
- Special situations for equipment handling, offloading, rigging and the installation of DC Stacks
- Temporary equipment laydown area provided on worksite
- No extreme irregularities with soil quality
- ALL onsite commissioning maximum of 2 weeks included application support, operation support, SCADA support, etc.
- Duties and tariffs in excess of 4% of BESS Equipment Value
- Excludes ALL PV/Solar work

Appendix B

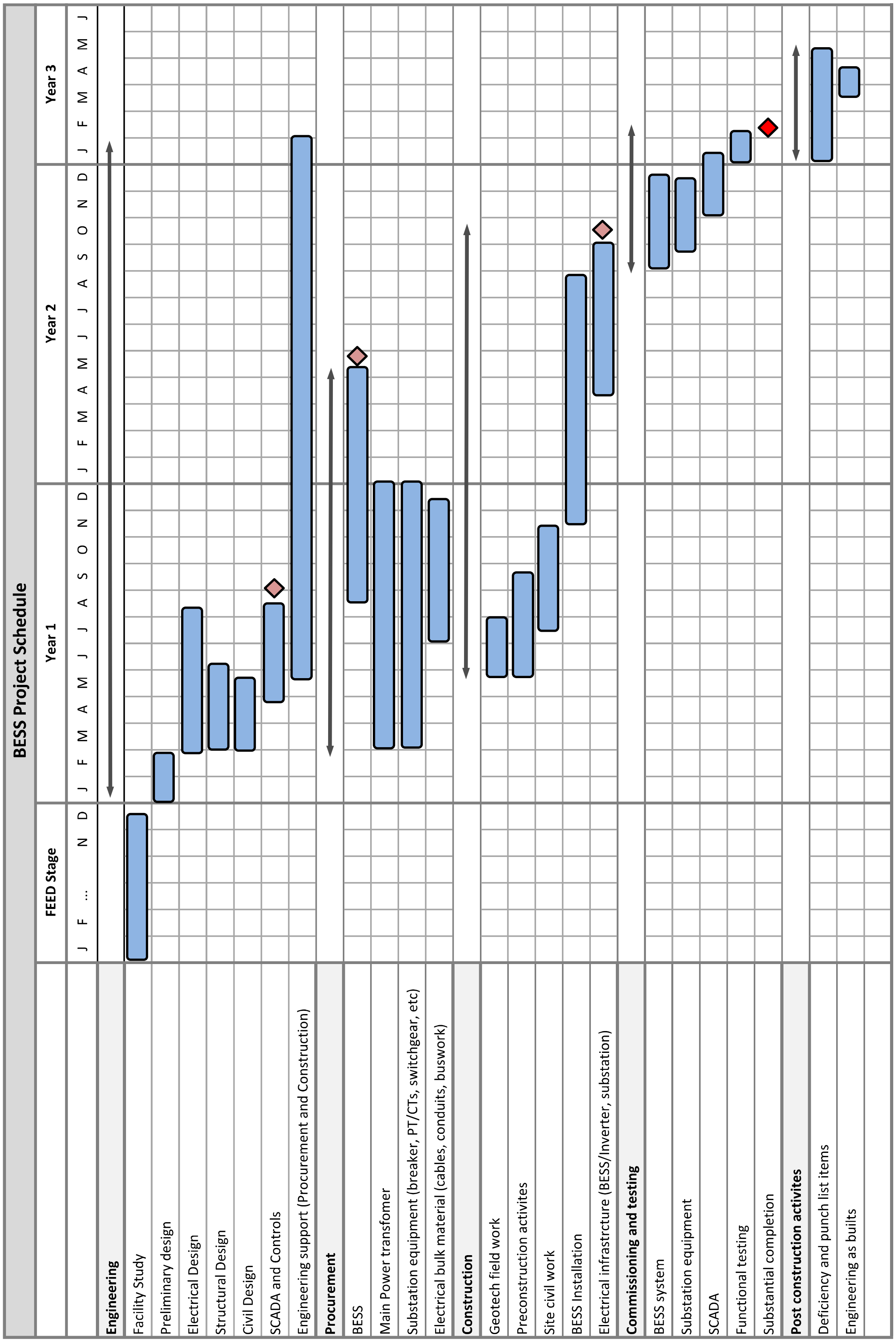
Cost Estimate

Class 5 Solar farm Estimate	20MWac BESS, 4 h reserve				
Size (MW)	20				
Duration (h)	4				
Size (MWh)	80				
Development Activities		***Description***	***PU cost ($ CAD)***	***Total***	***Comments***
Engineering and Permitting					
1	Interconnection Studies		1	$50,000	
2	Environmental Assessments		1	$50,000	
3	Permits and licenses		1	$50,000	
4	Site surveys		1	$50,000	
5	Geotech		1	$40,000	
6	Detailed Engineering		1	$480,000	Assumes 4000 hours with an average rate of $120/hour. Includes construction support and occasional site visits
7	Site management (site mtg, cost controller, safety		2	$160,000	
8	Owner Engineer Role		1	$60,000	Includes drawing review and approval, occassional site visit
	Subtotal - Engineering and Permitting			**$940,000**	
BESS area					**Installed costs**
1	AC BESS package	Quotes obtained from Sungrid solutions and Tesla	1	$30,395,000	Quotes includes civil works, foundation, MV transfomers, HVAC, enclosures, PCS, DC connections
2	AC/fiber cabling to Substation		100	$100,000	Assume $1000/meter
3	Civil Works		1	$200,000	Includes site clearing, service roads, grubbing, drainage, etc
4	BESS system commissioning		1	$100,000	Cost reference from another project.
	Subtotal - BESS Areas			**$30,795,000**	
Terminal area (69kV)					**Installed costs**
1	Main step up transformer			$750,000	Northern Transformer reference, 20MW (12/16/20MVA) 2 stage fan cooled, 35kV-69kV
2	69kV Motorized Disconnect Switch			$25,000	Cost reference from another project.
3	MV Surge arresters			$15,000	Cost reference from another project.
4	69kV circuit breaker			$250,000	Cost reference from another project.
5	69kV PT (for protection)			$80,000	
6	69kV Revenue Metering			$150,000	Cost reference from another project.
7	Addition to existing protection and control building			$200,000	Protection relays & racking, LV DC/AC wiring. It is assumed that new protection equipment will fit within existing P&C building
8	69kV support steel structures			$300,000	
9	Upgrade to station service transformer			$50,000	Aux power to BESS containers
10	35kV pad mount switchgear			$95,000	Reference to vendor quote (G&W)
11	Substation Civil works and foundation			$160,000	Internal references (includes foundation for main transformer, MV breaker, pad mount switchgear and support structures)
12	Substation testing and commissioning		1	$100,000	
13	Indirect Costs		1	$500,000	Equipment rentals, tools, etc.
	Subtotal - Terminal Area			**$2,675,000**	
	Contingency		**0.1**	**$3,500,000**	Assumes 10% (reference from another project)
	TOTAL			**$37,910,000**	

Class 5 Solar farm Estimate	50MWac BESS, 4 h reserve				
Size (MW)	50				
Duration (h)	4				
Size (MWh)	200				
Development Activities		***Description***	***PU cost ($ CAD)***	***Total***	***Comments***
Engineering and Permitting					
1	Interconnection Studies		1	$50,000	
2	Environmental Assessments		1	$50,000	
3	Permits and licenses		1	$50,000	
4	Site surveys		1	$50,000	
5	Geotech		1	$40,000	
6	Detailed Engineering		1	$540,000	Assumes 4500 hours with an average rate of $120/hour. Includes construction support and occasional site visits
7	Site management (site mtg, cost controller, safety		2	$180,000	
8	Owner Engineer Role		1	$80,000	Includes drawing review and approval, occasional site visit
	Subtotal - Engineering and Permitting			**$1,040,000**	
BESS area					**Installed costs**
1	AC BESS package	Quotes obtained from Sungrid Solutions and Tesla	1	$73,882,000	Quotes includes civil works, foundation, MV transformers, HVAC, enclosures, PCS, DC connections
2	AC/fiber cabling to Substation		200	$200,000	Assume $1000/meter
3	Civil Works		1	$350,000	Includes site clearing, service roads, grubbing, drainage, etc.
4	BESS system commissioning		1	$150,000	
	Subtotal - BESS Areas			**$74,582,000**	
Terminal area (69kV)					**Installed costs**
1	Main step up transformer			$1,250,000	Northern Transformer reference, 20MW (12/16/20MVA) 2 stage fan cooled, 35kV-69kV
2	69kV Motorized Disconnect Switch			$25,000	Cost reference from another project.
3	MV Surge arresters			$15,000	Cost reference from another project.
4	69kV circuit breaker			$250,000	Cost reference from another project.
5	69kV PT (for protection)			$80,000	
6	69kV Revenue Metering			$150,000	Cost reference from another project.
7	Addition to existing protection and control building			$200,000	Protection relays & racking, LV DC/AC wiring, power plant controller. It is assumed that new protection equipment will fit within existing P&C building
8	69kV support steel structures			$300,000	
9	Upgrade to station service transformer			$50,000	Aux power to BESS containers
10	35kV pad mount switchgear			$110,000	Reference to vendor quote (G&W)
11	Substation Civil works and foundation			$160,000	Internal references (includes foundation for main transformer, MV breaker, pad mount switchgear and support structures)
12	Substation testing and commissioning		1	$100,000	Includes interconnection costs
13	Indirect Costs		1	$500,000	Equipment rentals, tools, etc.
	Subtotal - Terminal Area			**$3,190,000**	
	Contingency		**0.1**	**$7,500,000**	Assumes 10% (reference from another project)
	TOTAL			**$86,312,000**	

Appendix C

Project Schedule


BESS Project Schedule
FEED Stage
Year 1
Year 2
Year 3
J F … N D
J F M A M J J A S O N D
J F M A M J J A S O N D
J F M A M J
Engineering
Facility Study
Preliminary design
Electrical Design
Structural Design
Civil Design
SCADA and Controls
Engineering support (Procurement and Construction)
Procurement
BESS
Main Power transfomer
Substation equipment (breaker, PT/CTs, switchgear, etc)
Electrical bulk material (cables, conduits, buswork)
Construction
Geotech field work
Preconstruction activites
Site civil work
BESS Installation
Electrical infrastrcture (BESS/Inverter, substation)
Commissioning and testing
BESS system
Substation equipment
SCADA
Functional testing
Substantial completion
Post construction activites
Deficiency and punch list items
Engineering as builts

NEWFOUNDLAND AND LABRADOR HYDRO

Evaluation of Island Hydroelectric Generation Expansion Alternatives

MAIN REPORT

SLI Document No. 691499-0000-40ER-1-0001

Date: October 21, 2022

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APPENDICES

1. EXECUTIVE SUMMARY

As part of its System Planning strategy, Newfoundland and Labrador Hydro ("Hydro") continuously assesses the electrical generation capacity required to meet power demands. Currently, an increased interest in power demand requires Hydro to consider the potential of undeveloped generation prospects in its portfolio.

This Study, ***Evaluation of Island Hydroelectric Generation Expansion Alternatives***, builds on 2018 work by Hydro by screening and ranking generation alternatives according to a pre-established set of criteria. The primary objective was to determine the gap in Project Planning maturity for a suite of prospects by comparing existing documentation against the requirements for completion of Front-End Execution Planning (FEEP). A secondary objective was identification of technical deficiencies and optimization opportunities through a review of existing documentation by the Engineering disciplines (e.g., Civil, Electrical, Mechanical, etc.).

A key assumption in this Study was that Project Planning, Screening and Ranking methods be consistent with industry practice for large capital projects (>$50 million). Such industry practice includes the Decision Gate Process for large capital projects, the Association for Advancement of Cost Engineering (AACE) Recommended Practices, the Heavy Civil Project Execution Standard and other internal SNC-Lavalin ("SLI") experience and best practices. It was also assumed that the Study should be conducted in keeping with the recommendations of the Commission of Inquiry Respecting the Muskrat Falls Project Report (March 5, 2020).

After a data and documentation review, including the assessment of previous costs and schedules and escalation of costs to Year-end 2022, a workshop was held to Screen and Rank the six (6) generation alternatives in Hydro's current portfolio against criteria such as capacity, cost, environmental impacts, market conditions, and so on. A Gap Analysis was performed to identify the level of effort required to bring the project documentation to the industry standard for "Pre-Sanction (Gate 3)", which is the typical final project sanction gate for major capital projects. The results of the Gap Analysis were then used to prepare the Scope of Work required to complete Front-End Execution Planning (FEEP) deliverables for each prospect. Subject Matter Experts (SMEs) also provided optimization opportunities for each prospect, including technical optimizations opportunities to improve cost and schedule certainty.

The resulting ranking of Hydroelectric Generation Expansion Alternatives was recommended as follows.

1. Bay d'Espoir Hydro Generating Unit 8
2. Addition of a Third Generating Unit Cat Arm
3. Island Pond Hydroelectric Development
4. Round Pond Hydroelectric Development
5. Portland Creek Hydroelectric Development
6. Exploits River Hydroelectric Developments

It is also recommended that Hydro align the Heavy Civil Project Execution Standard used in this Study with its Decision Gate Process. Hydro should also ensure that recommended deliverables / activities in the Standard be addressed prior to the relevant Decision Gate. It is further recommended that Hydro review and adopt, in whole or modified accordingly for its business, a Contracting Strategy Best Practice.

Hydro should also align its cost estimating procedures and its expectations of contractor(s) estimates with the Association for Advancement of Cost Engineering (AACE) Best Practices. The level of detail and quality of cost estimate to meet Gate 3 (Pre-Sanction) industry requirements will require completion of 40% to 70% of Project Definition deliverables. It must be acknowledged that this front-end work will be an expense even if the P85 cost estimate (the minimum suggested by the Commission of Inquiry) prove to be uneconomic.

Among other recommendations, Hydro should also carefully consider its sanction parameters for its portfolio of projects. This should take into consideration the need for power / energy and the importance of project cost estimate accuracy. These considerations should be balanced against pre-investment expenditures and pre-sanction commitments for the purchase of long-lead items, compared to the potential "lost value" of power / energy should first power be delayed by minimizing pre-sanction expenditures.

2. STUDY MANDATE

2.1. BACKGROUND

As part of its System Planning strategy, Newfoundland and Labrador Hydro ("Hydro") continuously assesses the electrical generation capacity required to meet power demands. Currently, an increased interest in power demand requires Hydro to consider the potential of undeveloped generation prospects in its portfolio. In 2018, Hydro compiled file information, cost and schedule estimates, and commissioned a Study to confirm that cost and schedule estimates for various generation alternatives were adequate for concept screening.

In its Professional Service Request of May 11, 2022, Hydro requested assistance with the screening and ranking of potential generation alternatives with the goal of recommending prospects for further study and evaluating the additional work required to complete Front-End Engineering Design (FEED)[1].

2.2. STUDY OBJECTIVES

The primary objective of this Study is the recommendation of generation alternatives for further study by determining the gap in Project Planning maturity of the prospects by comparing existing documentation against the requirements for completion of Front-End Execution Planning (FEEP)[1]. A secondary objective is the identification of technical deficiencies and optimization opportunities through a review of existing documentation by the Engineering disciplines (e.g., Civil, Electrical, Mechanical, etc.).

2.3. HYDROELECTRIC GENERATION EXPANSION PROSPECTS

Six (6) generation expansion prospects provided by Hydro for this Study are summarized in **TABLE 2-1** in descending order of degree of completeness of the Front-End Execution Planning (FEEP) stage. (Note: Prospect 6 includes two (2) subprojects.) Also shown is the "approximate position" of each prospect in a typical Phase Gate project lifecycle process used by Hydro, which is discussed further in **SECTION 3.2**.

TABLE 2-1 ISLAND HYDROELECTRIC GENERATION EXPANSION PROSPECTS

NO.	PROSPECT NAME	PHASE (approximate)
1	Bay d'Espoir Hydro Generating Unit 8	Phase 3 (near Gate 3)
2	Addition of a Third Generating Unit Cat Arm	Phase 1 / 2
3	Island Pond Hydroelectric Development	Phase 3
4	Round Pond Hydroelectric Development	Phase 1 / 2
5	Portland Creek Hydroelectric Development	Phase 2
6	Exploits River Hydroelectric Developments • Red Indian Falls • Badger Chute	Phase 1

[1] *Front-End Engineering Design (FEED)* is a major part of *Front-End Execution Planning (FEEP)*, a larger Project Planning effort that is considered the industry standard for execution planning of large Heavy Civil and Earthworks developments.

2.4. STUDY TASKS

The study was subdivided into five (5) main tasks, as follows.

TASK 1: Document Review

Review of documentation and data provided by Hydro for the prospects.

TASK 2: Assessment of Costs and Schedules

For each prospect, escalate the project cost to year-end (YE) 2022 and determine average project cost per installed megawatt ($ / MW), overall project development timeline, and construction timeline.

TASK 3: Screening and Ranking of Prospects

Screen and rank prospects using an Assessment Model appropriate for the level of study.

TASK 4: Identification of Optimization Opportunities

Identify opportunities that could add value to each prospect through a review of documents and data by the engineering disciplines (Electrical, Civil, Mechanical, etc.), e.g., a quality improvement to extend life cycle, reduce maintenance costs, improve operability, etc.

TASK 5: Development of a Go-Forward Plan

Perform a Gap Analysis to identify differences between current "planning maturity" and the maturity required to meet industry standard. For this study, a Gap Analysis was performed to identify differences between the current state of Project Planning maturity against the desired state of Project Planning maturity required to meet industry standard.

Prepare scope of work required to complete Front-End Execution Planning (FEEP) deliverables for each prospect, plus a Level 3 (L3) schedule to complete that work (see below for Schedule Level definition).

2.5. STUDY TEAM

Greg Snyder – Project Manager	Yasas Ponweera – SME Electrical
Brad Chaulk – Lead Project Execution Planner	Martin Landry – SME Mechanical
Kurt Kennedy – Project Execution Planner	Alan Parker – SME Environmental
Michel Tremblay – SME[2] Hydrotechnical	Karola Toth – Environmental Lead

2.6. ACKNOWLEDGEMENTS

The Study Team would also like to acknowledge the contributions and support of the following members of Hydro's Project Team: Brian Sparkes (Project Manager), Marc Cullen, Forhad Ahmad, Stephen Parsons and Evan Broderick.

2.7. DEFINITIONS

Annual Facility Usage – Sometimes known as Capacity Factor, it is the ratio of actual electrical energy output over time against the theoretical maximum electrical energy output over the same time (typically annually).

[2] SME = Subject Matter Expert

Class (#) Cost Estimate – A classification that describes the accuracy level of a cost estimate based on the degree of maturity of Project Definition Deliverables (see APPENDIX B).

Decision Gate Process – The division of the development of large capital projects into discrete Phases, separated by Decision Gates.

Decision Gate – A checkpoint where project status is formally reviewed by management and either (a) the project formally proceeds to the next Phase; (b) the project conditionally proceeds to the next Phase pending additional work or re-work; or (c) the project is suspended or cancelled.

DEP – Detailed Execution Planning.

FEED – Front-End Engineering Design

FEEP – Front-End Execution Planning.

Gap Analysis – Comparison of a “current state” against a “future state” or “desired state”.

Level (#) Schedule – A classification that describes the level of detail shown in a particular schedule (see **APPENDIX B**).

Management Contingency (Schedule) – A time period added to an overall project development timeline to account for unforeseen or uncontrollable delays.

Period of Analysis for Energy Study – The years of hydrological data used for completion of energy study(ies) used to assess hydropower projects. Energy Studies using older data sets generally need to be updated with more recent data, perhaps also including climate change considerations.

Project Definition – Commonly referred to as Conceptual Design, it is when concepts evolve to a point that project facilities are identified, initial scope of work developed, project layouts / schematics prepared, and project output/value is conceptualized.

Project Portfolio Management – Aligning project execution with corporate strategy to maximize the value of an entire portfolio of opportunities, to balance the portfolio to ensure that risks are properly considered, and to ensure that short-term results do not become the focus

Project Sanction – When a project is formally given the go-ahead by management to move into the execution phase (typically making a committing to construction).

SME – Subject Matter Expert is an individual with specialized knowledge in a specific field, e.g., engineering, environmental science, finance, etc.

Traffic Light Assessment Model – A rating system that uses simple RED, YELLOW and GREEN codes for evaluating the performance of an input against a predefined standard or set of criteria.

3. KEY ASSUMPTIONS

3.1. INDUSTRY PRACTICE

The Project Planning, Screening and Ranking methods used in this Study are consistent with industry practice for large capital projects (>$50 million) and internal SNC-Lavalin ("SLI") experience and best practices. It was also assumed that the Study be conducted in keeping with the recommendations in the report of the Commission of Inquiry Respecting the Muskrat Falls Project (March 5, 2020).

3.2. OVERALL DECISION GATE PROCESS

A "Decision Gate" process has been used by Hydro and affiliated companies to divide the development of large capital projects into discrete Phases, separated by Decision Gates. A Decision Gate is a checkpoint where project status is formally reviewed by management and either (a) the project formally proceeds to the next Phase; (b) the project conditionally proceeds to the next Phase pending additional work or re-work; or (c) the project is suspended or cancelled.

The Decision Gate Process shown in the flowchart in **FIGURE 3.1** represents the overall project lifecycle for power generation projects. This process was recognized as "best in class"[3] by a third-party auditor. The approximate position in the lifecycle of each of the generation prospects in this study is also shown in the flowchart. "Gate 3" is commonly known as "Project Sanction", so the prospects are all currently "Pre-Sanction".

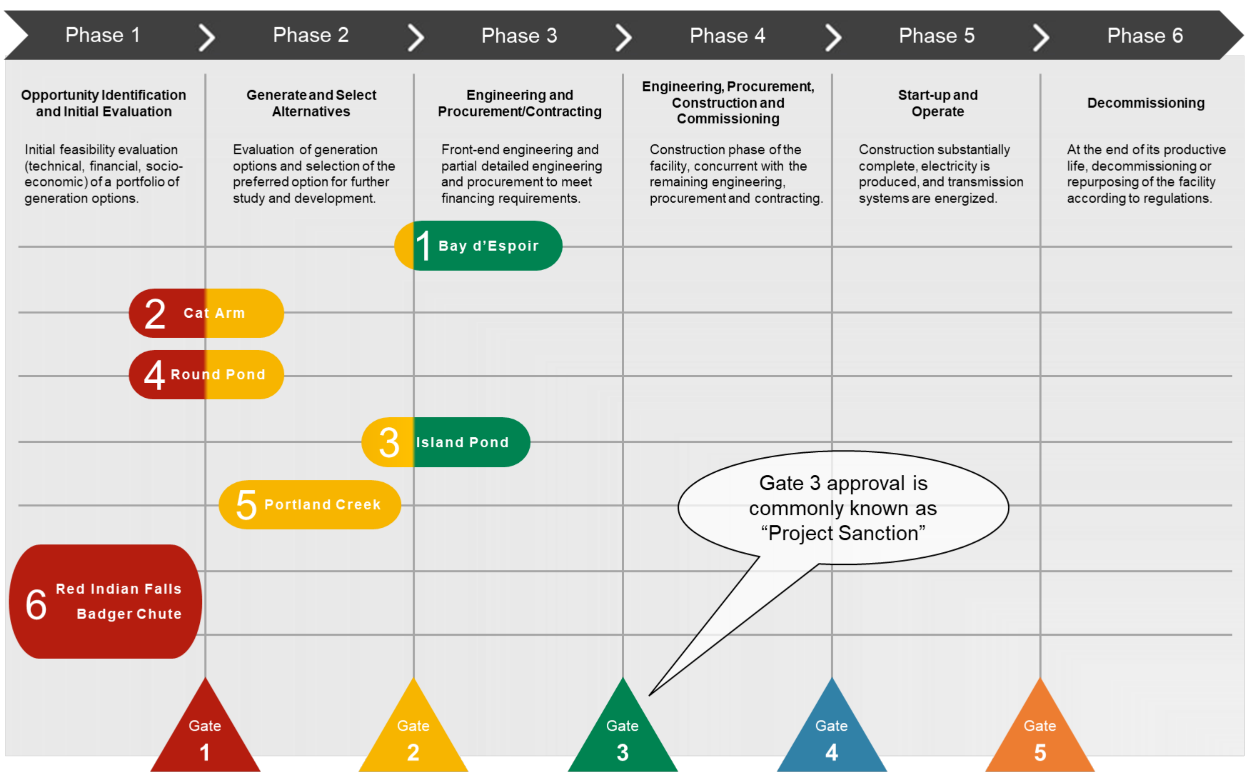

FIGURE 3.1 DECISION GATE PROCESS[2]

[3] After Grant Thornton LLP (July 16, 2018).

3.3. HEAVY CIVIL PROJECT EXECUTION STANDARD

Power generation projects generally have a significant Heavy Civil and Earthworks component. Project Execution Planning for this component follows a standard "sub-process" specific to the Heavy Civil deliverables required for power projects. For this study, the Heavy Civil Project Execution Standard shown in **FIGURE 3.2** was adopted as the basis for comparison of the design maturity of each prospect. Substantial completion of the deliverables listed for Stages 1 and 2 of the Standard is usually a requirement to pass Gate 3.

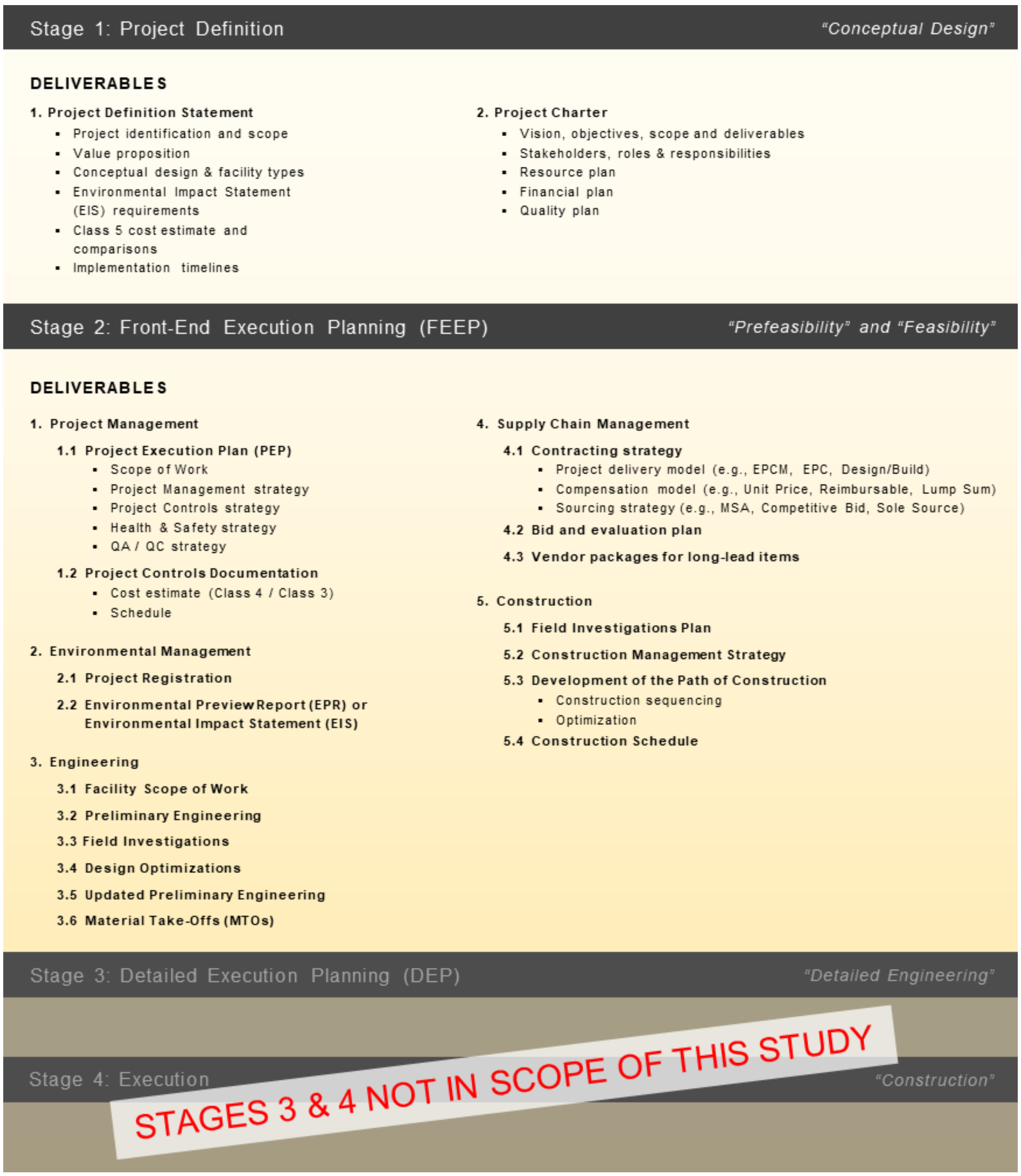

FIGURE 3.2 HEAVY CIVIL PROJECT EXECUTION STANDARD

STAGE 1 – PROJECT DEFINITION

The Project Definition stage, commonly referred to as Conceptual Design, is when concepts evolve to a point that project facilities are identified, initial scope of work developed, project layouts / schematics prepared, and project output/value is conceptualized. The key deliverable for Stage 1 is a Project Definition Statement that includes Project Definition and Scope, Conceptual Design, Timelines and Class 5 Cost Estimate[4].

STAGE 2 – FRONT-END EXECUTION PLANNING (FEEP)

The FEEP stage, commonly referred to as a *Feasibility Study*, is implemented when the Owner has decided to consider investment in a project. Depending on the Owner's risk profile (clearly stated by the Owner in a Project Charter), this stage can be undertaken as *Prefeasibility* and *Feasibility*. As a rule of thumb, undertaking this stage in two (2) separate steps usually results in approximately 30% additional planning cost.

> Step 1 is Early Front-end Execution Planning, commonly referred to as *Pre-FEED*, and involves developing the project definition, undertaking minimum field investigation to quantify the earthworks components, preparation of preliminary designs, construction sequencing plan (the precursor to the full Path of Construction[5] developed in Stage 3 – DEP), Level 2 (L2) Schedule, and Class 4 Cost Estimate[3].

> Step 2 is the completion of the Front-end Execution Plan, commonly referred to as FEED, which involves undertaking a detailed field investigation sufficient to complete all engineering requirements, followed by front-end execution planning that yields a Contracting Strategy[6], Level 3 (L3) Schedule and Class 3 Cost Estimate[3].

STAGE 3 – DETAILED EXECUTION PLANNING (DEP) *For information only (not in scope of this Study)*

Detailed Execution Planning (DEP), commonly referred to as Detailed Engineering, is where detailed engineering and execution planning are undertaken and procurement is implemented. Key deliverables include the Project Execution Plan (PEP), Engineering Work Packages (EWPs), Procurement Work Packages, Tender Documents, Evaluation/Award Recommendations, and Notices of Award.

STAGE 4 – EXECUTION *For information only (not in scope of this study)*

The Execution stage, commonly referred to as *Construction*, is where various contracts are issued and construction of the project takes place in three (3) main steps.

1. Construction Readiness, i.e., the initial step where Owner and contractor project documentation is finalized, approved, and issued for construction (IFC).
2. Construction, i.e., implementation and execution of each contract package.
3. Close-out, i.e., issuing of the final completion certificate, final payment certificate, and contractual closeout of each contract package.

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[4] Cost estimate classifications are based on the Association for Advancement of Cost Engineering (AACE) *Recommended Practice (RP) 18-R-97*. Schedule classifications are based on standard Primavera P6 practice.

[5] The *Path of Construction* is defined as the optimal sequencing of the building of a facility, developed by Construction, Engineering and Project Management Subject Matter Experts (SMEs), typically working backwards from the "end state".

[6] A "Contracting Strategy" is the sum of three main components: Project Delivery Model, Compensation Model, and Sourcing Strategy. The individual components are not contracting strategies.

3.4. COST AND SCHEDULE ASSUMPTIONS

Cost estimate classifications adopted in this report (e.g., Class 5, Class 3) are based on the Association for Advancement of Cost Engineering (AACE) Recommended Practice (RP) 18-R-97. Additional details are presented in **APPENDIX B: COSTS AND SCHEDULES**.

Similarly, terms such as “Level 1 Schedule” or “L1” are used in this report to describe the schedule level of detail, as described in **APPENDIX B: COSTS AND SCHEDULES.** In general, Level 1 and Level 2 schedules are developed as part of conceptual studies for program management and financial decision-making purposes.

4. TASK 1 – DOCUMENT REVIEW

4.1. DOCUMENT LIST

The documents provided to the Study Team by Hydro are listed in **APPENDIX A**: **DOCUMENT REVIEW** (see excerpt shown in **TABLE 4-1**).

4.2. REVIEW PROCESS

All documents were initially reviewed and screened by the Study Team Project Manager and Lead Project Execution Planner. Only material relevant to their technical discipline was then provided to the Subject Matter Experts (SMEs) for their review and assessment.

TABLE 4-1 DOCUMENT LIST EXCERPT FROM APPENDIX A

		DOCUMENT TITLE	DATE	REV.	AUTHOR(S)	DOCUMENT / PR
PROSPECT 1 BAY d'ESPOIR HYDRO GENERATING UNIT 8	1	Proposed Bay d'Espoir Hydro Generating Unit 8 HYDRAULIC ANALYSIS OF THE CONVEYANCE SYSTEM	March 22, 2018	00	SNC-Lavalin	647756-0000-40E
	2	Proposed Bay d'Espoir Hydro Generating Unit 8 CLASS 3 COST ESTIMATE AND PROJECT EXECUTION SCHEDULE	March 22, 2018	00	SNC-Lavalin	647756-0000-
	3	Final Report for Hydrology and Feasibility Study for Potential Bay d'Espoir Hydroelectric Generating Unit No. 8	December 11, 2020	0	Hatch	H363582-000
PROSPECT 2 ADDITION OF A THIRD GENERATING UNIT CAT ARM	4	CAT ARM DEVELOPMENT ADDITION OF UNIT # 3	September 13, 1985	-	Shawmont	Report No. SMR
	5	Addition of a Third Generating Unit, Cat Arm	August 24, 2018	-	NL Hydro	-
	6	Cat Arm Unit #3 Cost Estimate (August 24 2018)	August 24, 2018	-	Unspecified	-
PROSPECT 3 ISLAND POND HYDRO ELECTRIC DEVELOPMENT	7	Island Pond Development Final Feasibility Study January 1988 Volume 1 – Report	January 1988	-	Shawmont	Report No. SMR
	8	ISLAND POND / GRANITE CANAL RE-OPTIMIZATION AND COST UPDATE STUDY	January 14, 1997	-	AGRA Shawmont	SMR-05-96
	9	Studies for Island Pond Hydroelectric Project FINAL REPORT	December 2006	-	SNC-Lavalin	Project No. 7
	10	Portland Creek and Island Pond Hydroelectric Projects Update Cost Estimates	May 2012	PA	SNC-Lavalin	501325-40ER-0
	11	Island Pond Hydroelectric Development	August 29, 2018	-	NL Hydro	-
	12	Island Pond CADD Picture	Unspecified	-	Unspecified	-
	13	Feasibility Study Round Pond Development Summary Report	February 1989	-	NL Hydro Engineering Dept.	-
PROSPECT 4 ROUND POND HYDRO ELECTRIC DEVELOPMENT	14	Round Pond Hydroelectric Development – Update of the 1988 Cost Estimate (letter report)	May 7, 2012	-	Hatch	H341357-000
	[illegible]	Cost Estimate		-	Unspecified	

5. TASK 2: PREPARATION OF COSTS AND SCHEDULES

The following cost and schedule metrics were developed or updated for each Island Hydroelectric Generation Expansion prospect.

1. Total cost of each prospect, escalated to year-end 2022 (YE-2022).
2. Average cost per megawatt ($ / MW) of each prospect.
3. Overall Project Development Timeline for each prospect.
4. Construction Timeline for each prospect.

TABLE 5-1 summarizes the key technical metrics for the prospects, including updated cost estimates and the resulting average cost per megawatt ($ / MW) and other metrics. Cost estimates provided by Hydro from YE-2018 were escalated to YE-2022 as described below.

5.1. COST ESTIMATE ESCALATION TO YEAR-END 2022

In 2018, Hydro engaged a third-party consultant to conduct a cost and schedule estimate peer review to confirm if previous estimates for the generation alternatives were adequate for concept screening. As part of that peer review, cost estimates were escalated from the original date of the estimate to YE-2018. For this Study, the YE-2018 cost estimates were escalated to YE-2022 based on information from two (2) sources.

1. Statistics Canada *Canadian Construction Price Index* (CCPI) for the years 2019-21.
   - 2019: 2.2%   2020: 1.2%   2021: 11.4%
2. SLI Cost Estimating Department's inflation projection for 2022 for Newfoundland and Labrador. The projection was based on trends identified in construction works in which SLI is involved.
   - 2022: 15% (projection)

The net escalation to YE-2022 was, therefore, estimated at 132.5% of YE-2018 costs.

5.2. PROJECT SCHEDULES ASSESSMENT

Existing schedules for each prospect were assessed and adjustments made for Environmental Assessment timeline considerations and to reflect the requirements of the Heavy Civil Project Execution Standard for planning and executing a typical Heavy Civil project. Construction timelines were based on existing data and the Project Team's familiarity with the scope and type of work.

The adjusted schedules developed for each prospect, except for the Exploits River developments, are shown in **FIGURE 5.1** below.

As noted in **APPENDIX C – PROSPECT 6**, the level of planning and engineering required to support the Environmental Assessment Process for the Exploits River prospects will likely be very significant in terms of definition and scoping, but also very challenging in determining the cost and schedule implications. This is beyond the scope of the current study. As a result, the 1985 era schedules for Exploits River prospects were not included in FIGURE 5.1.

TABLE 5-1 KEY METRICS SUMMARY FOR ISLAND HYDROELECTRIC GENERATION EXPANSION PROSPECTS

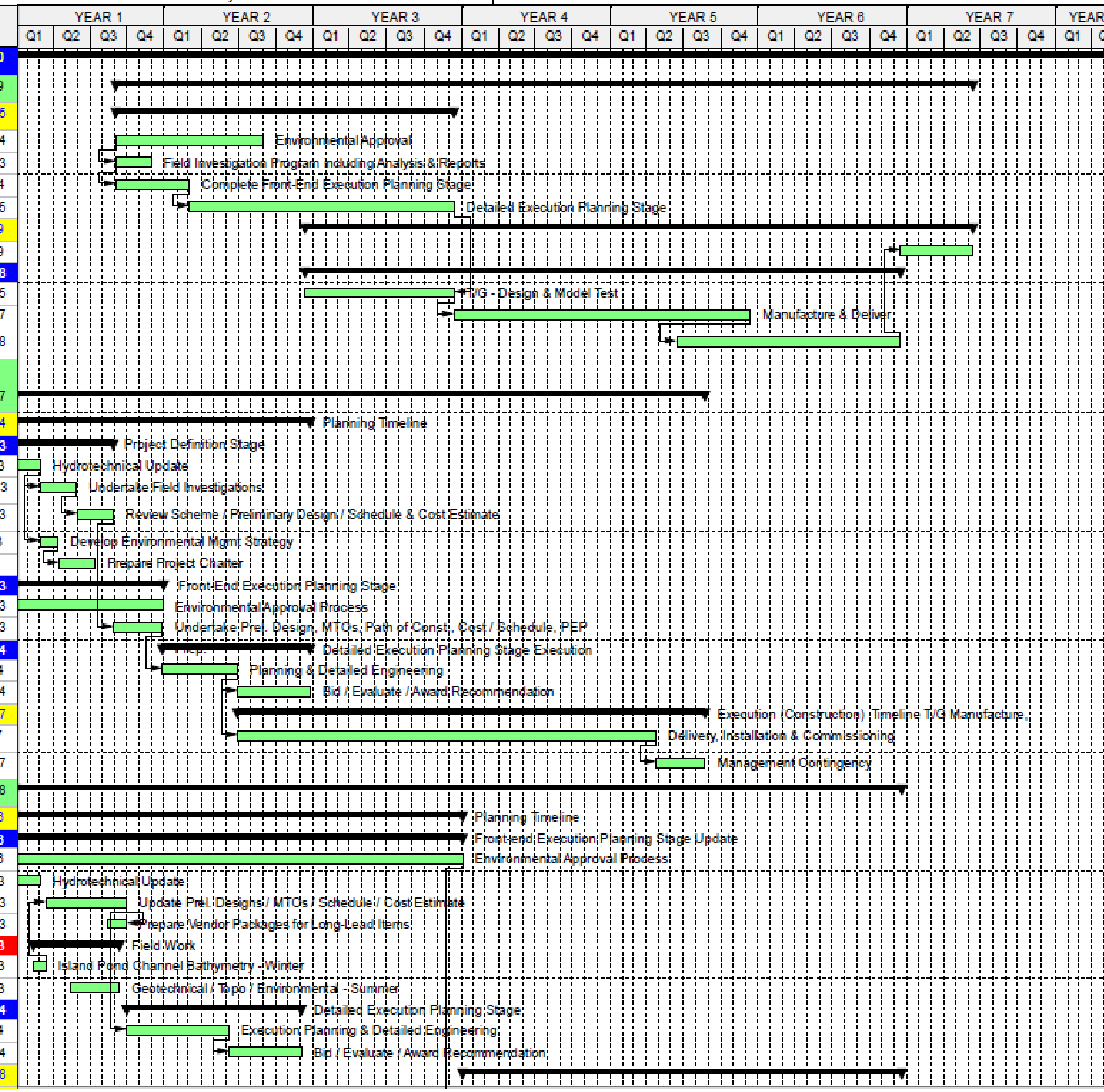
NO.	PROSPECT NAME	CAPACITY	TYPE	NO. OF UNITS	UNIT TYPE	PERIOD OF ANALYSIS FOR ENERGY STUDY[7]	COST YE-2018	COST YE-2022	M$ / MW YE-2022	M$ / GWh YE-2022	ANNUAL FACILITY USAGE[8]
1	BAY D'ESPOIR UNIT 8	150 MW	Storage	1	Francis	Probably 1970-2019	$393,688,684	$521,637,506	$3.5	$23.1	1.7%
2	CAT ARM ADDITION	68.2 MW	Storage	1	Pelton	Unspecified	$229,840,933	$304,539,236	$4.5	$12.2	4.2%
3	ISLAND POND	36 MW	Storage	1	Kaplan	1950-86	$405,200,154	$536,890,204	$14.9	$2.89	59.0%
4	ROUND POND	18 MW	Run-of-river	1	Bulb (Pit)	1950-86	$247,940,800	$328,521,560	$18.2	$2.36	88.2%
5	PORTLAND CREEK	23 MW	Storage	2	Pelton	Probably 1984-2005	$261,813,751	$346,903,220	$15.1	$2.44	70.5%
6	EXPLOITS RIVER • RED INDIAN FALLS • BADGER CHUTE	 42 MW 24 MW	 Run-of-river Run-of-river	 2 3	 Francis Francis	 Probably 1958-78 Probably 1958-78	 $392,632,346 $248,637,520	 $520,237,859 $329.444.713	 $12.4 $13.7	 $13.7 $12.4	 72.8% 73.2%

7 "Period of Analysis for Energy Study" refers to the years of hydrological data used for completion of the energy study(ies). Energy Studies using older data sets generally need to be updated with more recent data, perhaps also including climate change considerations.

8 "Annual Facility Usage" (sometimes also known as Capacity Factor) is the ratio of actual electrical energy output over a given period of time to the theoretical maximum electrical energy output over that same period (typically annually).

NL Hydro Generation Expansion - Project V2 — Classic Schedule Layout — 04-Oct-22 20:41

Activity ID	Activity Name	Original Duration	Start	Finish
HydroV2	NL Hydro Generation Expansion - Project \	2722	01-Jan-23	14-Jun-30
HydroV2.1	Bay d'Espoir	2112	03-Sep-23	14-Jun-29
HydroV2.1.1	Planning Timeline	832	03-Sep-23	12-Dec-25
A1000	Environmental Approval	365	03-Sep-23*	01-Sep-24
A1010	Field Investigation Program including Analysis & Reports	90	03-Sep-23	01-Dec-23
A1020	Complete Front-End Execution Planning Stage	182	03-Sep-23	02-Mar-24
A1030	Detailed Execution Planning Stage	650	03-Mar-24	12-Dec-25
HydroV2.1.2	Execution (Construction) Timeline	1645	13-Dec-24	14-Jun-29
A1050	Management Contingency	180	17-Dec-28	14-Jun-29
HydroV2.1.2.1	Turbine Generator	1465	13-Dec-24	16-Dec-28
A1060	T/G - Design & Model Test	365	13-Dec-24	12-Dec-25
A1070	Manufacture & Deliver	730	13-Dec-25	12-Dec-27
A1080	Install & Commission	550	16-Jun-27	16-Dec-28
HydroV2.2	Cat Arm	1695	01-Jan-23	22-Aug-27
HydroV2.2.1	Planning Timeline	725	01-Jan-23	25-Dec-24
HydroV2.2.1.1	Project Definition Stage	240	01-Jan-23	28-Aug-23
A1170	Hydrotechnical Update	60	01-Jan-23	01-Mar-23
A1180	Undertake Field Investigations	90	02-Mar-23	30-May-23
A1190	Review Scheme / Preliminary Design / Schedule & Cost	90	31-May-23	28-Aug-23
A1200	Develop Environmental Mgmt Strategy	45	02-Mar-23	15-Apr-23
A1210	Prepare Project Charter	90	16-Apr-23	14-Jul-23
HydroV2.2.1.2	Front-End Execution Planning Stage	365	01-Jan-23	31-Dec-23
A1220	Environmental Approval Process	365	01-Jan-23	31-Dec-23
A1230	Undertake Prel. Design, MTOs, Path of Const., Cost / S(	120	29-Aug-23	26-Dec-23
HydroV2.2.1.3	Detailed Execution Planning Stage	365	27-Dec-23	25-Dec-24
A1240	Execution Planning & Detailed Engineering	185	27-Dec-23	28-Jun-24
A1650	Bid / Evaluate / Award Recommendation	180	29-Jun-24	25-Dec-24
HydroV2.2.3	Execution (Construction) Timeline	1150	29-Jun-24	22-Aug-27
A1250	T/G Manufacture, Delivery, Installation & Commissioning	1030	29-Jun-24	24-Apr-27
A1260	Management Contingency	120	25-Apr-27	22-Aug-27
HydroV2.3	Island Pond	2180	01-Jan-23	19-Dec-28
HydroV2.3.1	Planning Timeline	1100	01-Jan-23	04-Jan-26
HydroV2.3.1.1	Front-end Execution Planning Stage Update	1100	01-Jan-23	04-Jan-26
A1270	Environmental Approval Process	1100	01-Jan-23	04-Jan-26
A1280	Hydrotechnical Update	60	01-Jan-23	01-Mar-23
A1320	Update Prel. Designs / MTOs / Schedule / Cost Estimate	200	15-Mar-23	30-Sep-23
A1330	Prepare Vendor Packages for Long-Lead Items	45	17-Aug-23	30-Sep-23
HydroV2.3.1.1.1	Field Work	211	13-Feb-23	11-Sep-23
A1290	Island Pond Channel Bathymetry - Winter	30	13-Feb-23*	14-Mar-23
A1300	Geotechnical / Topo / Environmental - Summer	120	15-May-23*	11-Sep-23
HydroV2.3.1.2	Detailed Execution Planning Stage	430	01-Oct-23	03-Dec-24
A1310	Execution Planning & Detailed Engineering	250	01-Oct-23	06-Jun-24
A1660	Bid / Evaluate / Award Recommendation	180	07-Jun-24	03-Dec-24
HydroV2.3.2	Execution (Construction) Timeline	1080	05-Jan-26	19-Dec-28



Actual Level of Effort — Actual Work — Remaining Work — Critical Remaining Work — ◆ Milestone — summary

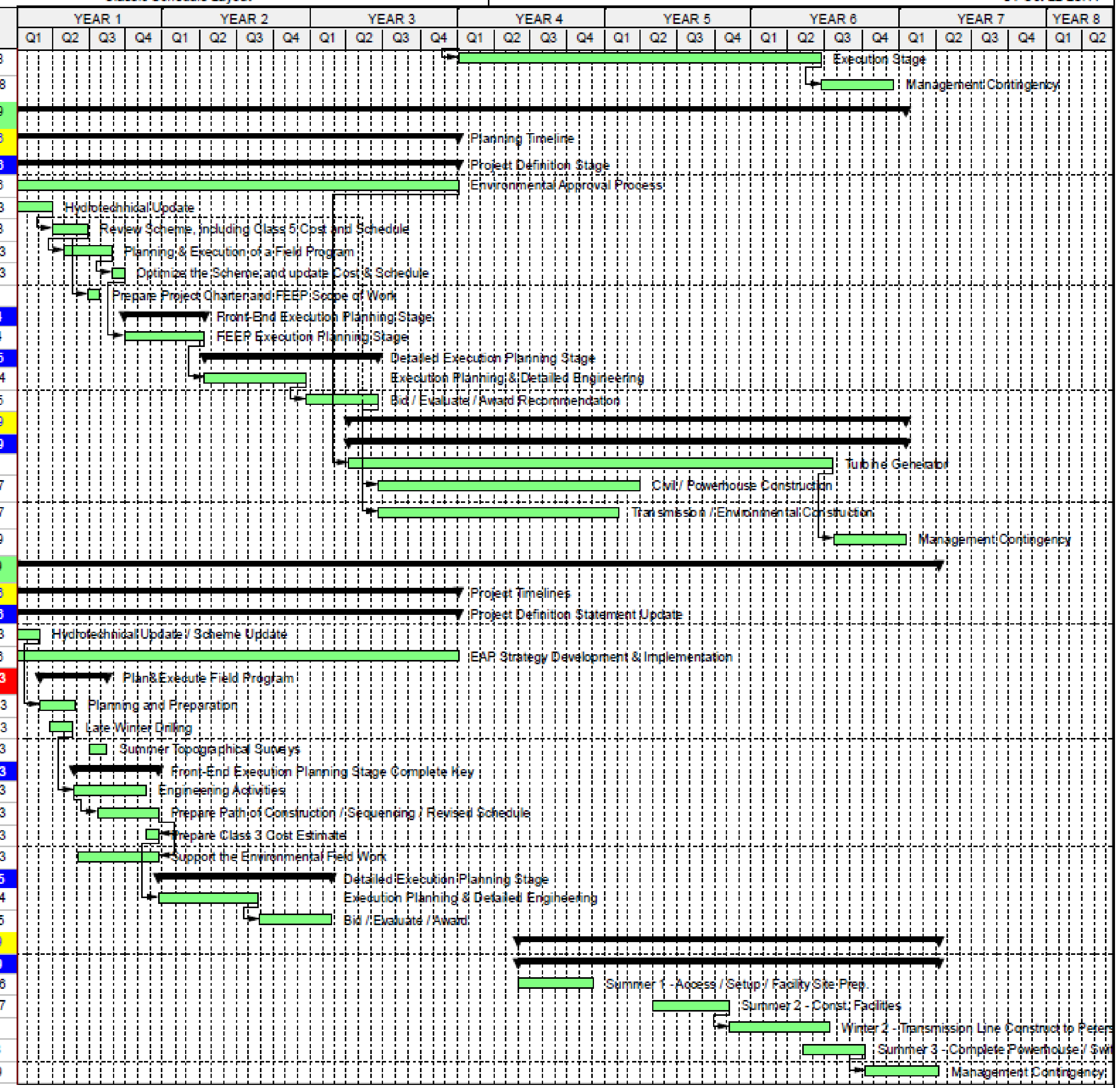
Page 1 of 2 — TASK filter: All Activities — © Oracle Corporation

FIGURE 5.1 ISLAND HYDROELECTRIC GENERATION EXPANSION ALTERNATIVES PROJECT SCHEDULES SUMMARY (page 1 of 2)

SNC·LAVALIN	EVALUATION OF ISLAND HYDROELECTRIC GENERATION EXPANSION ALTERNATIVES	Revision		Page
		Rev	Date	
	SLI Doc. No. 691499-0000-40ER-1-0001	01	21-OCT-2022	18

NL Hydro Generation Expansion - Project V2 — Classic Schedule Layout — 04-Oct-22 20:41

Activity ID	Activity Name	Original Duration	Start	Finish
A1400	Execution Stage	900	05-Jan-26	22-Jun-28
A1410	Management Contingency	180	23-Jun-28	19-Dec-28
HydroV2.4	Round Pond	2210	01-Jan-23	18-Jan-29
HydroV2.4.1	Planning Timeline	1100	01-Jan-23	04-Jan-26
HydroV2.4.1.1	Project Definition Stage	1100	01-Jan-23	04-Jan-26
A1340	Environmental Approval Process	1100	01-Jan-23	04-Jan-26
A1350	Hydrotechnical Update	90	01-Jan-23	31-Mar-23
A1360	Review Scheme, including Class 5 Cost and Schedule	90	01-Apr-23	29-Jun-23
A1370	Planning & Execution of a Field Program	120	01-May-23	28-Aug-23
A1380	Optimize the Scheme and update Cost & Schedule	30	29-Aug-23	27-Sep-23
A1390	Prepare Project Charter and FEEP Scope of Work	30	30-Jun-23	29-Jul-23
HydroV2.4.1.2	Front-End Execution Planning Stage	200	28-Sep-23	14-Apr-24
A1420	FEEP Execution Planning Stage	200	28-Sep-23	14-Apr-24
HydroV2.4.1.3	Detailed Execution Planning Stage	430	15-Apr-24	18-Jun-25
A1430	Execution Planning & Detailed Engineering	250	15-Apr-24	20-Dec-24
A1670	Bid / Evaluate / Award Recommendation	180	21-Dec-24	18-Jun-25
HydroV2.4.2	Execution (Construction) Timeline	1385	05-Apr-25	18-Jan-29
HydroV2.4.2.1	Execution Stage	1385	05-Apr-25	18-Jan-29
A1440	Turbine Generator	1205	05-Apr-25	22-Jul-28
A1450	Civil / Powerhouse Construction	650	19-Jun-25	30-Mar-27
A1460	Transmission / Environmental Construction	600	19-Jun-25	08-Feb-27
A1470	Management Contingency	180	23-Jul-28	18-Jan-29
HydroV2.5	Portland Creek	2291	01-Jan-23	09-Apr-29
HydroV2.5.1	Project Timelines	1100	01-Jan-23	04-Jan-26
HydroV2.5.1.1	Project Definition Statement Update	1100	01-Jan-23	04-Jan-26
A1480	Hydrotechnical Update / Scheme Update	60	01-Jan-23	01-Mar-23
A1490	EAP Strategy Development & Implementation	1100	01-Jan-23	04-Jan-26
HydroV2.5.1.1.1	Plan&Execute Field Program	168	02-Mar-23	16-Aug-23
A1510	Planning and Preparation	90	02-Mar-23	30-May-23
A1520	Late Winter Drilling	60	26-Mar-23*	24-May-23
A1530	Summer Topographical Surveys	45	03-Jul-23*	16-Aug-23
HydroV2.5.1.6	Front-End Execution Planning Stage	210	25-May-23	20-Dec-23
A1540	Complete Key Engineering Activities	180	25-May-23	20-Nov-23
A1550	Prepare Path of Construction / Sequencing / Revised Sc	150	24-Jul-23	20-Dec-23
A1560	Prepare Class 3 Cost Estimate	30	21-Nov-23	20-Dec-23
A1570	Support the Environmental Field Work	200	04-Jun-23	20-Dec-23
HydroV2.5.1.3	Detailed Execution Planning Stage	430	21-Dec-23	22-Feb-25
A1580	Execution Planning & Detailed Engineering	250	21-Dec-23	26-Aug-24
A1590	Bid / Evaluate / Award	180	27-Aug-24	22-Feb-25
HydroV2.5.2	Execution (Construction) Timeline	1044	01-Jun-26	09-Apr-29
HydroV2.5.2.1	Execution Stage	1044	01-Jun-26	09-Apr-29
A1600	Summer 1 - Access / Setup / Facility Site Prep.	190	01-Jun-26*	07-Dec-26
A1610	Summer 2 - Const. Facilities	190	01-May-27*	06-Nov-27
A1620	Winter 2 - Transmission Line Construct to Peters Barrens	250	07-Nov-27	13-Jul-28
A1630	Summer 3 - Complete Powerhouse / Switchyard and Trai	160	05-May-28*	11-Oct-28
A1640	Management Contingency	180	12-Oct-28	09-Apr-29



Actual Level of Effort — Actual Work — Remaining Work — Critical Remaining Work — ◆ Milestone — summary

Page 2 of 2

TASK filter: All Activities

FIGURE 5.1 ISLAND HYDROELECTRIC GENERATION EXPANSION ALTERNATIVES PROJECT SCHEDULES SUMMARY (page 2 of 2)

6. TASK 3: SCREENING AND RANKING OF PROSPECTS

6.1. PROJECT PORTFOLIO MANAGEMENT

Screening and ranking were conducted using the principles of Project Portfolio Management (PPfM) as a guide, and these principles align with Hydro's System Planning strategy. According to the Project Management Institute (PMI)[9], "*PPfM is fundamentally different from project and program management. Project and program management are about execution and delivery – doing projects right. In contrast, PPfM focuses on doing the right projects at the right time by selecting and managing projects as a portfolio of investments.*"

PPfM aligns project execution with corporate strategy to maximize the value of the entire portfolio, to balance the portfolio to ensure that risks are properly considered, and to ensure that short-term results do not become the focus. There are five (5) steps to be considered, as follows.

1. Determine business objectives.
2. Compile a list of potential projects and research them.
3. Assess the list of projects against relevant criteria (i.e., the main subject of this study).
4. Validate feasibility against available resources, prioritize and move forward on selected projects.
5. Manage and monitor the portfolio, including, as necessary, re-scoping, reallocating resources, etc.

Deciding which projects move forward is not always straightforward and it is often difficult to leave projects off the table. Screening and ranking processes ultimately involve people forming personal opinions based on data and value propositions. It is a subjective process, but it can be approached in a structured way, especially when project decisions will be under scrutiny by stakeholders and third parties.

6.2. ASSESSMENT MODELS

<u>"Traffic Light" Assessment Model</u>

Traffic Light Assessment is a rating system for evaluating performance against a predefined standard or set of criteria. For a study like this one, the model has the advantage of being easy to facilitate and completed quickly (see sample in **FIGURE 6.1**). With Hydro's approval, **<u>the Traffic Light model was adopted for this Study</u>**.

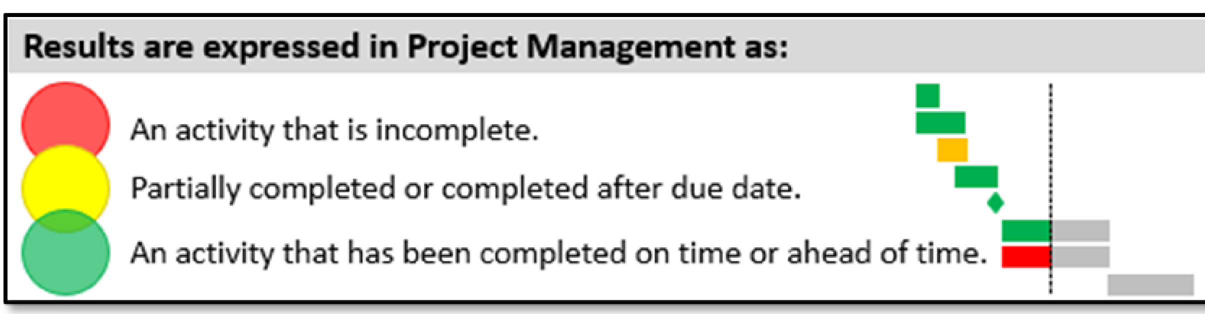


FIGURE 6.1 Traffic Light Assessment Model (used for this Study)
(Source: Continuous Improvement Toolkit)

[9] Oltmann, J. (2008). Project portfolio management: how to do the right projects at the right time. Paper presented at PMI® Global Congress 2008—North America, Denver, CO. Newtown Square, PA: Project Management Institute.

Qualitative Assessment Models *For information only (not in scope of this Study)*

A qualitative "risk rating" model, similar to Hydro's *Capital Risk Rating Matrix*, was another model considered for this study but requires more information than is available at this stage of the study. In such a model, ranking criteria are less general (i.e., more prescriptive) and are focused on outcomes/impacts that could affect project metrics like cost, schedule, quality, safety, environment, reputational impact, etc. Numerical rankings are determined by multiplying a numerical rating of the probability of the outcome with a numerical rating of the severity of the outcome (**Figure 6.2**). This type of model could be of value to Hydro prior to a major stage gate, such as Project Sanction (Gate 3).

Probability of outcome

Level	Score	Description
Very High	5	It is expected that the event will occur. If it does not occurs it will be a surprise.
High	4	The event has a great chance of occurring.
Medium	3	The event can occur.
Low	2	It will be a surprise if the event occurs.
Very Low	1	Very remote chance of the event to happen. Practically impossible.

Schedule impact

Level	Score	Description
Very High	5	Delays/Anticipation above 180 days or 6 months.
High	4	Delays/Anticipation between 120 and 180 calendar days.
Medium	3	Delays/Anticipation between 60 and 120 calendar days.
Low	2	Delays/Anticipation between 15 and 60 calendar days.
Very Low	1	Less than 15 calendar days of delays/anticipation.

Cost impact

Level	Score	Description
Very High	5	Variation (positive or negative) above $1,000,000.
High	4	Variation (positive or negative) between $500,000 and $1,000,000.
Medium	3	Variation (positive or negative) between $250,000 and $500,000.
Low	2	Variation (positive or negative) between $100,000 and $250,000.
Very Low	1	Variation (positive or negative) lower than $100,000.

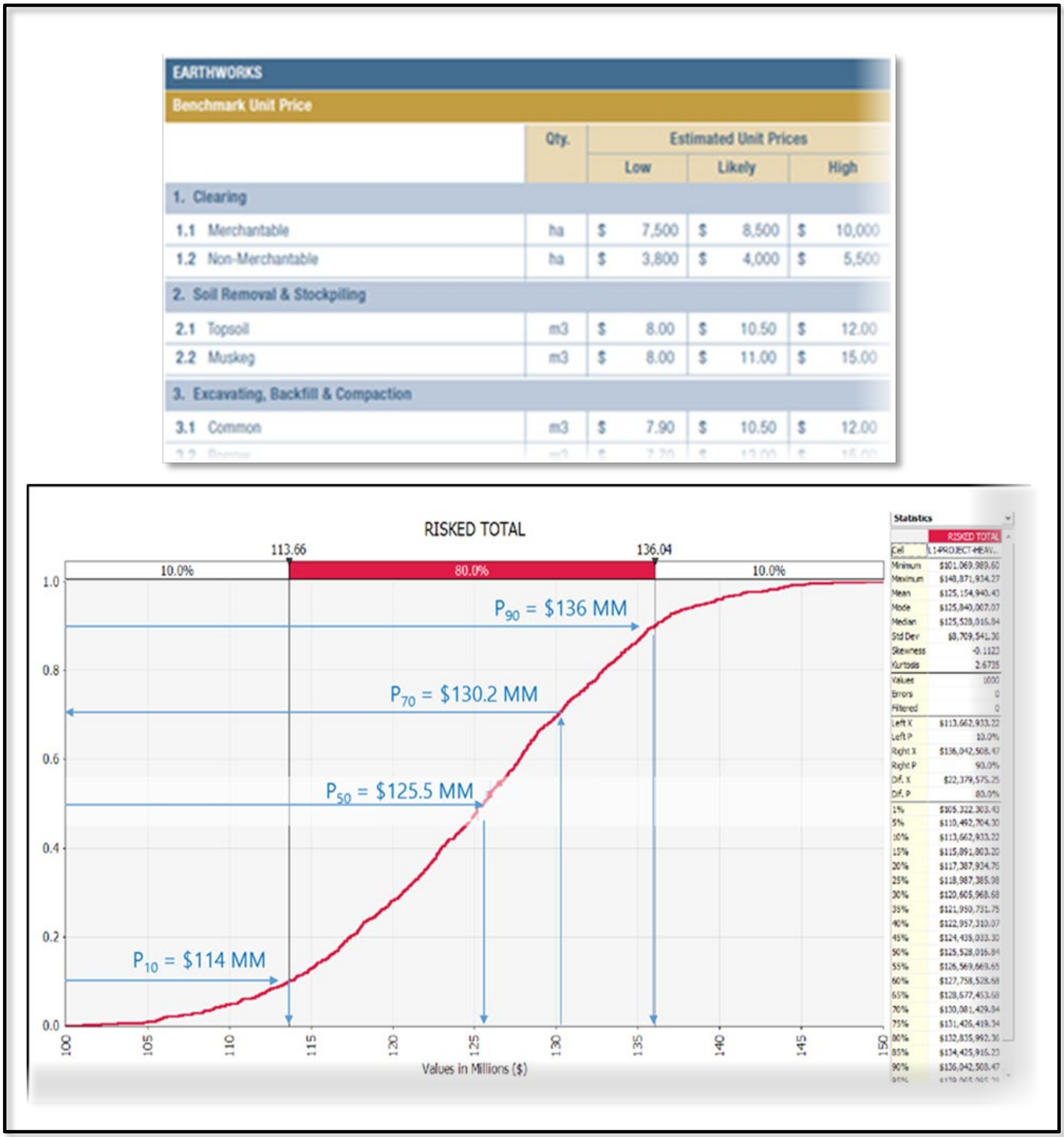
Environmental / reputational impact

Level	Score	Description
Very High	5	Crisis. Impact is so evident and public that the project could not proceed as planned.
High	4	Evident impact on environment/reputation.
Medium	3	Impact is perceived and raises concerns.
Low	2	Perceived impact on environment/reputation but without relevance.
Very Low	1	No impact on environment and reputation.

FIGURE 6.2 Example Qualitative Assessment Model
(Source: Project Management Institute – PMI)

<u>Quantitative Assessment Models</u> *For information only (not in scope of this Study)*

More detailed models such as quantitative risk analysis use techniques like Monte Carlo simulation to assess many combinations of probabilities and outcomes, and these techniques are usually reserved for detailed cost estimates with many hundreds or thousands (or more) quantities and unit costs. An example of a Monte Carlo simulation for a Class 3 cost estimate for a major civil project is shown in **FIGURE 6.3**.



EARTHWORKS								
Benchmark Unit Price								
	Qty.	Estimated Unit Prices						
		Low		Likely		High		
1. Clearing								
1.1 Merchantable	ha	$	7,500	$	8,500	$	10,000	
1.2 Non-Merchantable	ha	$	3,800	$	4,000	$	5,500	
2. Soil Removal & Stockpiling								
2.1 Topsoil	m3	$	8.00	$	10.50	$	12.00	
2.2 Muskeg	m3	$	8.00	$	11.00	$	15.00	
3. Excavating, Backfill & Compaction								
3.1 Common	m3	$	7.90	$	10.50	$	12.00	

FIGURE 6.3 Monte Carlo Simulation Example for Class 3 Cost Estimate

6.3. KEY RANKING CRITERIA

Defining the Ranking Criteria is an important part of portfolio management and is done in collaboration with senior management, project managers, and, in some cases, with stakeholders and customers. In consultation with Hydro, the Ranking Criteria shown in **TABLE 6-1** were developed and used in the Traffic Light Model screening and ranking process for this study. Feedback from projects executed in the past by (and for) Hydro was important in selecting these criteria. More criteria can be added later, based on study feedback.

CAPACITY Criteria

The project team confirmed CAPACITY criteria as follows.

1. As per **APPENDIX A: DOCUMENT REVIEW**
   - From previous studies and reports provided by Hydro, record and confirm relevant technical information, e.g., total expected installed capacity in megawatts (MW) of each prospect.
2. As per **APPENDIX C**: **PROSPECT OVERVIEWS, GAP ANALYSIS & RISKS**
   - From 2018 cost estimates for each prospect provided by Hydro, review and escalate costs from YE-2018 to YE-2022.
   - Based on the above, calculate $ / MW for each prospect.
   - Review and expand schedules/timelines to incorporate the full project development process.

WATER RIGHTS Criteria

A Water Right is the authorized use of surface water or groundwater by the governing authority(ies). At Hydro's request, WATER RIGHTS criteria were added to the screening and ranking process to capture issues related to water use for the prospects. For example, some prospects are already owned by Hydro, others are strictly on government (Crown) land, but others may have more complex ownership and approval issues. This study only addresses the perceived degree of effort required to secure the Water Rights for the prospect.

TABLE 6-1 KEY RANKING CRITERIA
(including Traffic Light Model examples)

CAPACITY				WATER RIGHTS
1. MW / COST PER MW INSTALLED		2. DEVELOPMENT / CONSTRUCTION TIMELINES		3. OWNERSHIP
MW Installed	$ x1,000 / MW	Development Timeline	Construction Timeline	
150	$3.48	5.8 Years	4.5 Years	Hydro

RISK CONSIDERATIONS							
4. ENVIRONMENTAL			5. SOCIO-ECONOMIC INFLUENCES	6. RELIABILITY CONSIDERATIONS	7. MARKET (CONSTRUCTION) CONDITIONS		
Environmental Impacts	Approval Timelines	Brownfield / Greenfield			Long-Lead Items	Contractor Availability	Contractor Capability
Manageable	1 Year	Brownfield	Manageable	Good	Challenging	Limited	Adequate

RISK CONSIDERATIONS Criteria

Project development issues that, historically, have had a measurable impact on cost, schedule, quality, safety and reputation of past projects are addressed in as Item 3. RISK CONSIDERATIONS.

- ENVIRONMENTAL considerations included technical issues, timelines and whether the project is Brownfield (a modification or addition to an existing facility) or Greenfield (a new facility).
- All energy projects must consider SOCIOECONOMIC INFLUENCES, and, for hydropower projects, these include impacts and benefits to land and resource use (e.g., First Nations traditional practice, recreation, tourism), economic resources (e.g., employment, sustainability), and community dynamics (e.g., education and training, community stability, infrastructure).
- RELIABILITY CONSIDERATIONS broadly include operations and maintenance complexity and efficiency and longevity of equipment.
- MARKET CONDITIONS are demographic and supply chain issues that may positively or negatively impact cost, schedule, quality, safety and reputation.

For this Study, Subject Matter Experts (SMEs) provided commentary on provincial Environmental Assessment (EA) approvals and permitting requirements, the provincial Project Registration documentation requirements, the federal Impact Assessment Act requirements, and the impacts of climate change on precipitation and temperature. This commentary is included in **APPENDIX D: ENVIRONMENTAL APPROVALS AND PERMITTING** and was referenced in the Screening and Ranking process.

6.4. SCREENING AND RANKING PROCESS

The Screening and Ranking process was completed by Hydro in a workshop held on September 28, 2022. Participants in the workshop were as follows.

1. Brian Sparkes – NL Hydro
2. Brad Chaulk – SNC-Lavalin
3. Evan Broderick – NL Hydro
4. Forhad Ahmad – NL Hydro
5. Greg Snyder – SNC-Lavalin
6. Marc Cullen – NL Hydro
7. Stephen Parsons – NL Hydro

For each prospect, a Traffic Light Assessment was performed on each metric in the Key Ranking Criteria matrix. Each metric was assigned either a RED, YELLOW or GREEN ranking status based on qualitative and quantitative assessments of the metric, using the experience and judgement of the workshop attendees. While there is subjectivity in this approach, the method is considered practical for this level of study.

6.5. SCREENING AND RANKING BASIS

A description of the rationale used by workshop participants to rank each metric is included below.

Prospect 1: Bay d'Espoir Hydro Generating Unit 8

1. <u>MW / Cost per MW Installed</u>. This project has the highest capacity (150 MW) and the lowest project development cost ($3.48 per MW Installed) among the prospects and these metrics are, therefore, classified as GREEN.
2. <u>Development / Construction Timelines</u>. These timelines are classified YELLOW due to the uncertainty around the Turbine Generator design, testing, manufacture, and delivery time.
3. <u>Water Rights</u>. Water Rights are owned by Hydro and are classified as GREEN.

4. Environmental. As this is a Brownfield site and the environment impacts are considered manageable, these metrics are classified GREEN.
5. Socioeconomic. Again, as this is Brownfield site, the socioeconomic impact is considered manageable and the metric is classified as GREEN.
6. Reliability. The project is adjacent to an existing powerhouse and will have good access, make use of existing transmission routes, and use equipment similar to existing. Reliability is classified as GREEN.
7. Market (Construction) Conditions. The Green Energy construction market is already showing signs of becoming extremely busy over the next two (2) to four (4) years and will impact this project if Hydro decides to proceed within the next twelve (12) months. Therefore, the supply of Long-Lead equipment and Contractor Availability are classified as RED. Due to the considerable experience gained by contractors in eastern Canada because of muskrat Falls, the contractor capability metric has been classified as YELLOW.

Prospect 2: Addition of a Third Generating Unit Cat Arm

1. MW / Cost per MW Installed. This prospect has the second-highest capacity (68 MW) and the second-lowest project development cost ($4.47 per MW Installed) of the prospects. The project documentation is 1985-vintage and it is very likely that updated hydrology will result in an increased capacity, therefore the capacity is classified as GREEN. However, the cost per MW has been assigned YELLOW due to the age of the project documentation (1985) and whether or not a new transmission line is required.
2. Development / Construction Timelines. These timelines are classified YELLOW due to scope uncertainly because of the age of the project documentation (1985). An update to the Project Definition Statement is necessary and changes in the scheme could impact timelines.
3. Water Rights. Water Rights are owned by Hydro and are classified as GREEN.
4. Environmental. As this is a Brownfield site, and the environmental impacts considered manageable, these metrics are classified GREEN.
5. Socioeconomic. The socioeconomic impact is considered manageable for this Brownfield site and this metric is classified as GREEN.
6. Reliability. The project is adjacent to an existing powerhouse and will have good access, make use of existing transmission routes, and use equipment similar to existing. Reliability is classified as GREEN.
7. Market (Construction) Conditions. Assuming the Cat Arm project would start four-to-seven (4-7) years after Bay d'Espoir, market conditions are difficult to predict. Therefore, the availability of major equipment and contractor availability has been classified as YELLOW. Due to the considerable experience gained by contractors in eastern Canada from the Muskrat Falls Project and given that this project is smaller and (slightly) less complex than Bay d'Espoir, the contractor capability metric has been classified as GREEN.

Prospect 3: Island Pond Hydroelectric Development

1. MW / Cost per MW Installed. The project would mainly be an energy producer and its project documentation (2006) close to FEEP-Stage completion, but the hydrology has to be updated. It is ranked as third priority and is classified as GREEN in terms of MW installed. After redoing the hydrology, the scheme could be revisited and, with increased storage, could produce more capacity.
2. Development / Construction Timelines. The development timeline is driven by the forecasted three (3)-year environmental assessment and approval period. There is some uncertainty around this timeline due to the lack of component environmental studies which could have a positive or negative impact

on the timeline. Therefore, this metric is classified as YELLOW. The construction of the Works is within the bounds of normal heavy civil work and there is a reasonable degree of certainty of a three (3)-year construction timeline, therefore this metric is classified as GREEN.

3. Water Rights. Water Rights are owned by Hydro and are classified as GREEN
4. Environmental. Due to the minimum flooding of the reservoirs and the remoteness of the site, environmental impacts are considered as manageable. However, given that this is a Greenfield site, the metric has been classified as YELLOW.
5. Socioeconomic. Due to the remoteness of the site, socioeconomic impacts are considered as manageable and have been classified as GREEN.
6. Reliability. The project is within the watershed of the Bay d'Espoir system, will have good access and is close to existing transmission routes. Reliability is classified as GREEN.
7. Market (Construction) Conditions. For this metric, it has been assumed that construction may begin within the next ten (10) years and could be affected by the forecasted boom in the green energy industry. Therefore, the long-lead items and contractor availability metrics have been classified as YELLOW. Due to the relative technical simplicity of this project, the contractor capability metric has been classified as GREEN.

Prospect 4: Round Pond Hydroelectric Development

1. MW / Cost per MW Installed. The project is mainly an energy producer and its project documentation (1987-89) was pre-feasibility level, but it must be updated in terms of hydrology. It is ranked as fourth in priority and is classified as YELLOW in terms of MWs installed, due to uncertainty with the key project parameters. By redoing the hydrology, the scheme could be revisited and with increased storage, could add more capacity. A redefined project with all environmental impacts addressed will likely affect the cost and, therefore, the Cost per MW is classified as RED.
2. Development / Construction Timelines. The development timeline is driven by the forecasted three (3)-year period for environmental assessment and approval. There is some uncertainty around this timeline due to the lack of component environmental studies which could have a positive or negative impact on the timeline. Therefore, this metric is classified as YELLOW. The construction of the Works is within the bounds of normal heavy civil work and there is a reasonable degree of certainty around a three (3)-year construction timeline, therefore this metric is classified as GREEN.
3. Water Rights. Water Rights are owned by Hydro and are classified as GREEN.
4. Environmental. Due to the minimum flooding of the reservoirs and the remoteness of the site, environmental impacts are considered as manageable. However, given that this is a Greenfield site, the metric has been classified as YELLOW.
5. Socioeconomic. Due to the remoteness of the site, socioeconomic impacts are considered as manageable and have been classified as GREEN.
6. Reliability. The project is within the watershed of the Bay d'Espoir system and will have good access. It is also reasonably close to existing facilities for maintenance and repair resources. Reliability is classified as GREEN.
7. Market (Construction) Conditions. – Due to the type and relatively small size of the Turbine Generator, the procurement of long-lead items is not anticipated to be difficult and this metric has been classified as GREEN. Contractor Availability has been classified as YELLOW due to the uncertainty related to the project development timeline. Due to the relative simplicity of this project, the contractor capability metric has been classified as GREEN.

Prospect 5: Portland Creek Hydroelectric Development

1. MW / Cost per MW Installed. The project is mainly an energy producer and its project documentation (2007) is close to FEEP-Stage completion, but the hydrology must be updated. It is ranked as fifth in priority and is classified as GREEN in terms of MWs installed. By redoing the hydrology, the scheme could be revisited and with increased storage, could produce more capacity. In 2007, access to the site was proposed from Daniel's Harbour, but with access now available via the LIL access road, which pass directly through the watershed, there is potentially a significant change in access cost. Therefore, the Cost per MW has been classified as YELLOW.
2. Development / Construction Timelines. The development timeline is driven by the forecasted three (3)-year period for environmental assessment and approval. However, due to the remoteness of the site, and the potential to change the access location, this timeline could be notably shorter. Therefore, the Development Timeline metric has been classified as RED. The project is relatively small and not difficult in terms of civil construction, but the construction season is limited to summer and fall months and, therefore, the construction timeline has been classified as YELLOW.
3. Water Rights. Water Rights are owned by the Crown and are classified as YELLOW.
4. Environmental. Due to the minimum flooding of the reservoirs and the remoteness of the site, environmental impacts are considered as manageable. However, given that this is a Greenfield site, the metric has been classified as YELLOW.
5. Socioeconomic. Due to the remoteness of the site, the socioeconomic impacts are considered manageable and have been classified as GREEN.
6. Reliability. The project site is remote and currently without access and may make access for maintenance and repair difficult. Concerns about reliability will need to be addressed in the design. Reliability is therefore classified as YELLOW.
7. Market (Construction) Conditions. Due to the type and relatively small size of the Turbine Generator(s), the procurement of long-lead items is not anticipated to be difficult and this metric has been classified as GREEN. Contractor Availability has been classified as YELLOW due to the uncertainty related to the project development timeline. Due to the relative simplicity of this project, the Contractor Capability metric has been classified as GREEN.

Prospect 6: Exploits River Hydroelectric Developments

1. MW / Cost per MW Installed. These prospects are "Run of River" projects and, as such, are energy producer. Due to the age of the project documentation (1950-60's era) and the lack of information concerning environmental impacts (which are considered high), the MW installed metric has a high probability of changing and is classified as RED. The Class 5 Cost Estimates were updated in 2005, but the environmental impacts have not been fully identified, therefore the Cost per MW is classified as YELLOW.
2. Development / Construction Timelines. Due to the unknowns pertaining to the environmental impacts and the resulting mitigations, timelines are uncertain and this metric is classified as RED.
3. Water Rights. Water Rights are owned by the Crown and are classified as YELLOW.
4. Environmental. For same reasons as item 2. above , this metric is classified as RED
5. Socioeconomic. For same reasons as item 2. above, this metric is classified as RED.
6. Reliability. The design of these sites is not sufficiently advanced to properly assess reliability issues. Reliability is therefore classified as YELLOW.

7. Market (Construction) Conditions. Due to the type and relatively small size of the Turbine Generator(s), the procurement of long-lead items is not expected to be difficult and this metric has been classified as GREEN. Contractor Availability has been classified as YELLOW due to the uncertainty related to the project development timeline. Due to the relative simplicity of these projects, the Contractor Capability metric has been classified as GREEN.

6.6. SCREENING AND RANKING RESULTS SUMMARY

The results of the Screening and Ranking process are summarized in **TABLE 6-2** below.

TABLE 6-2 SCREENING AND RANKING RESULTS SUMMARY

PROSPECT	CAPITAL COST ESTIMATE ($ x 1,000 escalated to YE 2022)	CAPACITY				WATER RIGHTS	RISK CONSIDERATIONS							
		1. MW / COST PER MW INSTALLED		2. DEVELOPMENT / CONSTRUCTION TIMELINES		3. OWNERSHIP	4. ENVIRONMENTAL			5. SOCIO-ECONOMIC INFLUENCES	6. RELIABILITY CONSIDERATIONS	7. MARKET (CONSTRUCTION) CONDITIONS		
		MW Installed	$ x1,000 / MW	Development Timeline	Construction Timeline		Environmental Impacts	Approval Timelines	Brownfield / Greenfield			Long-Lead Items	Contractor Availability	Contractor Capability
1. Bay d'Espoir Hydro Generating Unit 8	$520	150	$3.48	5.8 Years	4.5 Years	Hydro	Manageable	1 Year	Brownfield	Manageable	Good	Challenging	Limited	Adequate
2. Addition of a Third Generating Unit Cat Arm	$305	68.2	$4.47	5.2 Years	3.2 Years	Hydro	Manageable	1 Year	Brownfield	Manageable	Good	Uncertain	Uncertain	Good
3. Island Pond Hydroelectric Development	$535	36	$14.91	6.0 Years	3 Years	Hydro	Manageable	3 Years	Greenfield	Manageable	Good	Uncertain	Uncertain	Good
4. Round Pond Hydroelectric Development	$330	18	$18.25	5.6 Years	3.3 Years	Hydro	Manageable	3 Years	Greenfield	Manageable	Good	Good	Uncertain	Good
5. Portland Creek Hydroelectric Development	$345	23	$15.08	6.3 Years	3.1 Years	Crown	Manageable but with issues	3 years	Greenfield	Manageable	Uncertain	Good	Uncertain	Good
6. Red Indian Falls Hydroelectric Development	$520	42	$12.39	Unknown	Unknown	Crown	Likely high	>3 years	Greenfield	Likely high	Uncertain	Good	Uncertain	Good
6. Badger Chute Hydroelectric Development	$330	24	$13.73	Unknown	Unknown	Crown	Likely high	>3 Years	Greenfield	Likely high	Uncertain	Good	Uncertain	Good

7. TASK 4: OPTIMIZATION OPPORTUNITIES

7.1. PORTFOLIO MANAGEMENT

Project Portfolio Management (PPfM) is the industry standard for compiling and managing a portfolio of projects over an extended period. PPfM can help optimize project resources, lower environmental, engineering and project management costs, provide opportunities for Supply Chain optimization (and lower the cost of major equipment supply), and provide construction sequencing opportunities over the entire portfolio, thereby lowering construction cost.

Should Hydro decide to proceed with several of the projects over a 10 to 15-year period, there would be an opportunity to use a Portfolio Management approach to plan and implement these projects.

For example, Hydro's Island Hydroelectric Generation Expansion project portfolio could consist of four (4) programs, as follows.

- Program A – BDE and Cat Arm
- Program B – Island Pond and Round Pond
- Program C – Northern Peninsula West
- Program D – Exploits River

Program A – BDE and Cat Arm

BDE and Cat Arm are Brownfield projects that are similar in scope. Therefore, concurrent execution with staggered discipline activities would result in efficient use of human, material, and equipment resources. For example, executing BDE as a distinct project followed by Cat Arm as a separate project would take around ten to twelve (10 to 12) years. Executing both projects concurrently, using one prime contractor, would likely take only six to seven (6 to 7) years.

Program B – Island Pond and Round Pond

Island Pond and Round Pond are in proximity on the existing Bay d'Espoir watershed, are similar in scope, and environmental issues are likely the same or very similar. Therefore, treating these projects as one program with two projects will greatly reduce planning time, reduce environmental planning level of effort, and result in construction cost savings and timeline reductions, similar to that outlined for Program B.

Program C – Northern Peninsula West

The construction of the Labrador Island Link (LIL) has provided construction access to several watersheds on the western side of the Great Northern Peninsula. Several small-scale hydro projects (15 to 30 MW range) that were previously encumbered by the cost and environmental impact of constructing access could now be viable.

Program D – Exploits River

The hydro resources of the Exploits River (Badger Chute and Red Indian Falls) have long been recognized but come with environmental challenges. However, future development of these resources could be acceptable as part of a renewable energy strategy or as other generation options are built or economic analysis deems them unviable to develop.

7.2. GENERAL OPTIMIZATIONS

A high-level review of the selected turbine generators was undertaken by an SME and the following feedback was provided.

1. Turbine Generator Selection

    - The type of units listed for each generation facility appears reasonable except for Badger Chute and Red Indian Falls. A Francis unit is not recommended as both head and flows are too low.
    - Model tests will be required for the larger size units, namely BDE 150 MW. For Cat Arm, a model test for a 68 MW Pelton unit might not be necessary. The other units are closer to a standard design and model testing is usually not required.
    - Previous reports and studies included quotes by North American suppliers on typical timelines for design, manufacturing, and installation of turbine generators. For this study, these quotes were reviewed by SMEs and found to be reasonable for YE-2022 except for BDE, as follows.
        - BDE — 48 months (39 months used in 2018 schedule)
        - Cat Arm — 34 months
        - Island Pond — 30 months
        - Round Pond — 33 months
        - Portland Creek — 19 months
        - Red Indian Falls / Badger Chute — 36 months

      For this study, SMEs also confirmed that suppliers Andritz, Voith and Alstom are generally busy and are likely to be even busier due to increased demand for energy. Other manufactures in China, for example, could be considered. In addition, pricing is volatile and suppliers will not guarantee pricing very long.
    - Based on the above, calculate $ / MW for each prospect.
    - Review and expand schedules/timelines to incorporate the full project development process.

2. Schedule Critical Items

    - Water to Wire (W2W) Equipment Packages are Long-Lead Items and the larger size turbine generator unit design, manufacturing, and installation timeline will likely form the critical path item for the construction schedule.

7.3. SPECIFIC OPTIMIZATIONS

Individual optimization opportunities for each prospect are presented in **APPENDIX C**: **PROSPECT OVERVIEWS, GAP ANALYSIS & RISKS**.

8. TASK 5: GO-FORWARD PLAN

8.1. METHODOLOGY

The main objective of this Study was to determine the current level of completeness of Project Planning for each of the generation prospects. This was done by performing a Gap Analysis to identify the differences between the current "planning maturity" and the maturity required to meet the industry standard for Pre-Sanction (Gate 3), which is the completion of Front-End Execution Planning (FEEP).

The results of the Gap Analysis were then used to prepare the Scope of Work required to complete the Front-End Execution Planning (FEEP) deliverables for each prospect ("FEEP Requirements"). The overall Project Development Timeline and Construction Timeline was also assessed for each prospect.

Details of the Gap Analysis and the FEEP Requirements for each prospect are presented in **APPENDIX C: PROSPECTS OVERVIEW, GAP ANALYSIS & RISKS**.

8.2. GAP ANALYSIS RESULTS

Using the list of deliverables for Stage 1 and Stage 2 of the Heavy Civil Project Execution Standard (see **SECTION 3.3**), the degree of completion ("% Complete") of each deliverable was measured by assessing the current state of each deliverable against the standard.

Results are presented in two (2) levels of detail, as follows.

1. **Summary Level** that uses colour-coding to quickly show the design maturity status of each prospect (see **TABLE 8-1** below).
2. **Detailed Level** Excel spreadsheet that allows sorting of information by development stage, technical discipline, deliverable, % complete, etc. This spreadsheet is included as an attachment to this report and a hardcopy of the spreadsheet is included as an attachment to **APPENDIX C**.

8.3. WORK REQUIRED TO COMPLETE FRONT-END PLANNING STAGES

Details for each prospect are provided in **APPENDIX C**. In general, the Project Definition Statements (see **SECTION 10.5**) should be updated for all prospects (except BDE Unit 8) after Hydrotechnical reviews and, in the case of Portland Creek, a potential change in site access should be considered.

TABLE 8-1 GAP ANALYSIS SUMMARY

	PROSPECT 1 Bay d'Espoir				PROSPECT 2 Cat Arm				PROSPECT 3 Island Pond				PROSPECT 4 Round Pond				PROSPECT 5 Portland Creek				PROSPECT 6 Red Indian Falls				PROSPECT 6 Badger Chute			
STAGE 1: PROJECT DEFINITION	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%
Project Definition Statement												SEE 1																
Project Charter																												
Hydrology / Power & Energy Update																												
STAGE 2: FRONT-END EXECUTION PLANNING (FEEP)																												
PROJECT MANAGEMENT	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%
Project Execution Plan																												
Project Controls - Cost Estimate																												
Project Controls - Schedule																												
ENVIRONMENTAL MANAGEMENT	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%
Prepare Project Registration													SEE 2															
Preparation of EPR or EIS													SEE 2															
ENGINEERING	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%
Facility Scope of Work																												
Preliminary Engineering																												
Field Investigations																												
Design Optimizations																												
Updated Preliminary Engineering																												
Material Take-Off (MTO)																												
SUPPLY CHAIN	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%
Contracting Strategy																												
Bid and Evaluation Plan																												
Vendor Packages for Long-Lead Items																												
CONSTRUCTION	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%	25%	50%	75%	100%
Field Investigations																												
Construction Management (CM) Strategy																												
Development of Path of Construction																												
Construction Schedule																												

LEGEND

- Complete
- Some work completed, e.g., >75% but <100%
- Incomplete

NOTES

1. Island Pond may require a review of hydrology.
2. Original Round Pond Environmental Submission was not provided by Hydro.

9. CONCLUSIONS

9.1. PROSPECTS SUMMARY

The six (6) Island Hydroelectric Generation Expansion Alternatives can be grouped into the following two (2) technical categories.

Brownfield Projects (expansion of generating capacity of existing facilities)

1. Bay d'Espoir (BDE) Unit 8
2. Cat Arm Addition of a Third Generating Unit

Greenfield Projects (development and construction of new facilities)

3. Island Pond
4. Round Pond
5. Portland Creek (plus the potential for adjacent watersheds, referred to as Northern Peninsula West)
6. Exploits River
    - Red Indian Falls
    - Badger Chute

From an Environmental Approvals perspective, Brownfield projects are generally less demanding than Greenfield Projects.

For the Brownfield projects, the development timelines are driven by the time to design, manufacture, deliver, install and commission the turbine generators. For (smaller) Greenfield projects, development timelines are driven by the estimated three (3) year timeline for the Environmental Approval Process.

9.2. SANCTIONING CRITERIA

The standard industry approach to pre-sanctioning activities is to balance financial risk against the front-end planning level of effort, which effectively translates into "cost estimate accuracy". This balance is a matter of overall financial risk of a cost overrun during construction that can be absorbed by the project versus the Owner's ability to absorb the pre-investment financial cost should the project not proceed.

The optimal cost estimate level of accuracy at the Project Sanction Gate is achieved by completing the engineering design, tendering the work and receiving firm contractor pricing. However, this requires additional pre-sanction spending.

10. RECOMMENDATIONS

10.1. PROPOSED PROSPECT RANKING

As detailed in **SECTION 6** herein, the following ranking of Island Hydroelectric Generation Expansion Alternatives is recommended.

1. Bay d'Espoir
2. Cat Arm
3. Island Pond
4. Round Pond
5. Portland Creek
6. Exploits River
   - Red Indian Falls
   - Badger Chute

10.2. DECISION GATE PROCESS

It is recommended that Hydro continue to follow its "best in class" Decision Gate Process and align the Heavy Civil Project Execution Standard used in this Study (see **SECTION 3.3**) with the phases of that process. Recommended additions to that Standard are detailed in **SECTION 10.4** below. Hydro should also ensure that recommended deliverables / activities in the Standard be addressed prior to the relevant Decision Gate.

10.3. GATE 3 (PRE-SANCTION) COST ESTIMATING REQUIREMENTS

It is recommended that Hydro align its cost estimating procedures and its expectations of contractor(s) estimates with the Association for Advancement of Cost Engineering (AACE) Best Practices. This is considered an important step in addressing the following Key Recommendation in the report of the Commission of Inquiry Respecting the Muskrat Falls Project (March 5, 2020).

> 5. The Government of Newfoundland and Labrador should proceed to fund large projects using a probability value of not less than P85. As well, recognizing the
>
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>
> likelihood of bias in any cost and schedule estimate, government should require the project proponent to provide a range of cost estimates in order to establish the project's budget, so that government can determine its own risk appetite. Amounts for tactical and strategic risks should be included in the overall budget but should not be specifically identified or quantified when disclosure is made to the public. Government should authorize the release of dollar amounts for tactical and strategic risks only on pre-determined, structured and well-defined terms.

The level of detail and quality of cost estimate to meet Gate 3 (Pre-Sanction) industry requirements should be at least AACE Class 3 and, in cases where market conditions or technical uncertainty is high, Class 2. This will require completion of 40% to 70% of Project Definition deliverables prior to Gate 3 (see **APPENDIX B**). It must be acknowledged that this front-end work may be a "sunk cost" should the P85 estimate be uneconomic.

In order to determine the P85-level cost estimate, a Monte Carlo simulation (risk analysis) will be required to generate a cumulative probability curve. The simulation demands a robust and transparent cost estimate, with ranges for unit costs and quantities endorsed by Cost Engineering and Risk Management SMEs. Independent external experts will also likely review and challenge aspects of the estimate and the risk analysis.

10.4. CONTRACTING STRATEGY BEST PRACTICE

It is recommended that Hydro review and adopt, in whole or modified accordingly for its business, the COAA Best Practice *DEVELOPING A CONTRACTING STRATEGY.*[10] The purpose of this Best Practice is to ensure that Project Owners have comprehensively considered Project specifics (goals/objectives, work environment, scopes of work, Project and contract risk allocation), weighed the pros and cons in consultation with all of the key Parties and clearly articulated the appropriate Contracting Strategy for the Project.

10.5. HEAVY CIVIL PROJECT EXECUTION STANDARD MODIFICATIONS

It is recommended that Stages 1 and 2 of the Heavy Civil Project Execution Standard used in this Study be modified to optimize the Standard for the Island Hydroelectric Generation Expansion Alternatives. This is due primarily to the need to revisit the hydrology for the prospects (except BDE Unit 8).

STAGE 1: Project Definition Stage Update

It is recommended that *Stage 1: Project Definition* deliverables / activities be modified to include the following.

- Hydrotechnical Update and resulting Scheme Update, including hydrology and power/energy calculations which include recent data and climate change projections.
- Development of an Environmental Management Strategy and filing of Project Registration documentation with the Regulatory Authority.
- Preliminary Field Investigation work to firm up Project Definition assumptions and contribute to the Environmental Management Strategy.

STAGE 2: Front-End Execution Planning (FEEP)

It is recommended that Stage 2: Front-End Execution Planning (FEEP) deliverables / activities be modified to include the following.

- Due to the length of the Environmental Approval process, it is recommended to combine Stage 2: FEEP and Stage 3: Detailed Execution Planning (DEP) to shorten overall development timelines for the prospects. While this will result in lower overall project planning costs, it will increase the pre-sanction financial exposure for Hydro should a project not proceed.

  Note: Concurrent planning of two similar projects (e.g., BDE and Cat Arm) by one project team will contribute to mitigating the "time gaps" in the planning process due to the lengthy environmental approval timelines.

10.6. ISLAND GENERATION POTENTIAL

To fully understand the power / energy potential of the island, it is recommended that watersheds and potential hydro resources of the Exploits River and the western side of the Great Northern Peninsula be identified, followed by Project Definition work for the most viable resources.

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[10] COAA (March 2018).

10.7. PORTFOLIO MANAGEMENT CONSIDERATIONS

Should Hydro decide to proceed with two (2) or more of these projects, it is recommended that Hydro adopt a Project Portfolio Management (PPfM) approach for planning and execution of the Island Hydroelectric Generation Expansion Alternatives. For example, if the first four (4) Alternatives were considered, two (2) programs could evolve.

Program A – BDE and Cat Arm

Program B – Island Pond and Round Pond

10.8. SANCTION PARAMETERS

It is recommended that Hydro carefully consider its sanction parameters for this portfolio of projects. This should take into consideration the need for power / energy and the importance of project cost estimate accuracy. These considerations should be balanced against pre-investment expenditures and pre-sanction commitments for the purchase of long-lead items, compared to the potential “lost value” of power / energy should first power be delayed by minimizing pre-sanction expenditures.

10.9. RELIABILITY CONSIDERATIONS

Reliability of hydroelectric facilities covers a broad range of topics and is an important design consideration for facility Owners. It will often mean selecting a more robust design and using equipment with a proven track record of reliability, including data on mean time to failure of equipment. Consideration should also be given to equipment and material source and quality control of manufacturing.

The experience of the Owner and maintenance crews is also an important consideration in reliability. Using the same or similar systems will make maintenance easier and improve overall reliability, and the use of equipment and systems that are tried-and-proven is important to ensure reliability.

The Owner should provide designers with information on its existing systems and equipment preferences so these can be considered in the design. Some systems may be outdated and better alternatives are usually available, although overly complex systems may be difficult and expensive to maintain.

Redundancy of equipment and of power supplies and critical operations equipment should also be considered. This can also include routing of cabling, telecommunications systems and ensuring access alternatives so that the plant can continue to operate at all times.

The Owner’s reliability expectations need to be clear and expressly communicated to the designer. These expectations come through in specifications as direction to the contractor for material and equipment selection and for construction approaches. For Muskrat Falls, for example, the Owner provided a series of “Design Philosophy” documents that provided direction on the design approach.

Improving of reliability can be more costly at the design and construction stage – sometimes called the “gold plated solution” – but it generally proves its worth in the long term through increased time in operation, reduced maintenance and longer service life for the facility.

10.10. RISK CONSIDERATIONS

Project-specific risks for each of the Island Hydroelectric Generation Expansion prospects are outlined in **APPENDIX C**. However, there is an overarching risk consideration that will apply to the entire portfolio.

The key risk to planning and executing any heavy civil project over the next five-to-ten (5-10) years will be post-pandemic global supply chain challenges and the retirement of many the “baby boomer” generation from the workforce. For renewable energy projects, this situation is further aggravated by the predictions of a construction boom. For hydroelectric projects, timelines for major equipment, i.e., water-to-wire (W2W) packages, will be lengthy, fuel cost will be volatile, and there will be technical and craft labour shortages.

The are several ways to mitigate this risk.

1. Owner clarity around cost and schedule objectives, including which has priority and what are the limitations of that priority.
2. Innovative approaches to project contracting strategies will be necessary.
3. The single biggest variable to schedule can be Project Sanction criteria. Early financial commitments on environmental, engineering, and major equipment purchase can reduce the time to first power by 12-to-18 months.

Therefore, it is recommended that Hydro carefully consider its cost and schedule objectives for the proposed Island Hydroelectric Generation Expansion Alternatives and ensure these objectives are reflected in its Project Charter, Project Contracting Strategy and Sanction Parameters.

APPENDIX A

DOCUMENT REVIEW

		DOCUMENT TITLE	DATE	REV.	AUTHOR(S)	DOCUMENT / PROJECT NO.	TYPE
PROSPECT 1 **BAY d'ESPOIR HYDRO GENERATING UNIT 8**	1	Proposed Bay d'Espoir Hydro Generating Unit 8 HYDRAULIC ANALYSIS OF THE CONVEYANCE SYSTEM	March 22, 2018	00	SNC-Lavalin	647756-0000-40ER-I-0001-00	PDF
	2	Proposed Bay d'Espoir Hydro Generating Unit 8 CLASS 3 COST ESTIMATE AND PROJECT EXECUTION SCHEDULE	March 22, 2018	00	SNC-Lavalin	647756-0000-40ER-I-0002-00	PDF
	3	Final Report for Hydrology and Feasibility Study for Potential Bay d'Espoir Hydroelectric Generating Unit No. 8	December 11, 2020	0	Hatch	H363582-00000-228-230-0001	PDF
PROSPECT 2 **ADDITION OF A THIRD GENERATING UNIT CAT ARM**	4	CAT ARM DEVELOPMENT ADDITION OF UNIT # 3	September 13, 1985	-	ShawMont	Report No. SMR-30-85	PDF
	5	Addition of a Third Generating Unit, Cat Arm	August 24, 2018	-	NL Hydro	-	MS Word
	6	Cat Arm Unit #3 Cost Estimate (August 24 2018)	August 24, 2018	-	Unspecified	-	MS Excel
PROSPECT 3 **ISLAND POND HYDROELECTRIC DEVELOPMENT**	7	Island Pond Development Final Feasibility Study January 1988 Volume 1 – Report	January 1988	-	ShawMont	Report No. SMR-02-88	PDF
	8	ISLAND POND / GRANITE CANAL RE-OPTIMIZATION AND COST UPDATE STUDY	January 14, 1997	-	AGRA ShawMont	SMR-05-96	PDF
	9	Studies for Island Pond Hydroelectric Project FINAL REPORT	December 2006	-	SNC-Lavalin	Project No. 722720	PDF
	10	Portland Creek and Island Pond Hydroelectric Projects Update Cost Estimates	May 2012	PA	SNC-Lavalin	501325-40ER-0001-PA	PDF
	11	Island Pond Hydroelectric Development	August 29, 2018	-	NL Hydro	-	MS Word
	12	Island Pond CADD Picture	Unspecified	-	Unspecified	-	MS Word
PROSPECT 4 **ROUND POND HYDROELECTRIC DEVELOPMENT**	13	Feasibility Study Round Pond Development Summary Report	February 1989	-	NL Hydro Engineering Dept.	-	PDF
	14	Round Pond Hydroelectric Development – Update of the 1988 Cost Estimate (letter report)	May 7, 2012	-	Hatch	H341357-0000-00-218-0001	PDF
	15	Round Pond Cost Estimate	2018	-	Unspecified	-	MS Excel
	16	Interconnection Requirements - Supply Adequacy Hydro Alternatives (pp. 19-27)	February 26, 2018	-	NL Hydro	Doc #: TP-TN-023	PDF
	17	PROJECT PROPOSAL SUMMARY Round Pond Hydroelectric Development	May 14, 2018	-	Nalcor Energy	-	MS Excel
	18	Round Pond Hydroelectric Development	August 30, 2018	-	NL Hydro	-	MS Word
	19	Round Pond Transmission Estimate	Unspecified	-	Unspecified	-	PDF

Continued…

		DOCUMENT TITLE	DATE	REV.	AUTHOR(S)	DOCUMENT / PROJECT NO.	TYPE
PROSPECT 5 **PORTLAND CREEK HYDROELECTRIC DEVELOPMENT**	20	Feasibility Study for Portland Creek Hydroelectric Project	January 2007	-	SNC-Lavalin	Project No. 722736	PDF
	21	See item 10 for Prospect 3 above					
	22	Portland Creek Cost Estimate	2018	-	Unspecified	-	MS Excel
	23	Interconnection Requirements - Supply Adequacy (pp. 28-37)	February 26, 2018	-	NL Hydro	Doc #: TP-TN-023	PDF
	24	PORTLAND CREEK INTERCONNECTION	April 12, 2018	A	NL Hydro	(drawing PCKTS Rev A.skf)	PDF
	25	PROJECT PROPOSAL SUMMARY Portland Creek	May 14, 2018	-	Nalcor	-	MS Excel
	26	Portland Creek Hydroelectric Development	August 29, 2018	-	NL Hydro	-	MS Word
PROSPECT 6 **EXPLOITS RIVER HYDROELECTRIC DEVELOPMENTS** • **RED INDIAN FALLS** • **BADGER CHUTE**	27	DRAWING Plan of Damsite Badger Chute (1 p.)	7-12-1933	-	Anglo-Newfoundland	1571 D	PDF
		PROPOSED 20,000 H.P. HYDRO-ELECTRIC POWER PLANT AT RED INDIAN FALLS PRELIMINARY ESTIMATE (2 pp.)	October 31, 1957	-	Anglo-Newfoundland	-	PDF
	28	MEMO Notes on Completion of Construction and Operation of Surge Tank (5 pp.)	August 12, 1958	-	E.R. Davis	File 1904	PDF
	29	PRELIMINARY EVALUATION OF POWER REQUIREMENTS AND SOURCES (9 pp.)	January 14, 1959	-	E.R. Davis	Report No. 1915	PDF
	30	EXPLOITS RIVER HYDRO INVENTORY STUDY (88 pp.)	February 29, 1980	-	ShawMont	SMR-11-79	PDF
	31	LETTER Badger Chute Hydroelectric Development (5 pp.)	February 15, 2002	-	AMEC	-	PDF
	32	LETTER Badger Chute	February 20, 2002	-	American Hydro Corp	Inquiry Number 2491	PDF
	33	Exploits River Hydro Potential (Red Indian Falls, Badger Chute & Four Mile Pond) Preliminary Project Assessment (12 pp.)	January 28, 2005	-	NL Hydro	-	PDF
	34	Exploits River Projects Preliminary Results (1 p.)	February 14, 2005	-	NL Hydro	-	PDF
	35	Minutes of Meeting Exploits River Hydro Potential (18 pp.)	February 23, 2005	-	SGE Acres	-	PDF
	36	Badger Chute Hydro Development Capital Cost Estimate	April 18, 2018	-	NL Hydro	-	MS Excel
	37	Badger Chute Hydro Development Capital Cost Estimate	August 24, 2018	-	NL Hydro	Revision to April 18, 2018 file	MS Excel
	38	Transmission Planning Direction for Supply Adequacy Study	July 25, 2018	-	NL Hydro	E-mail by Robert Collett	PDF
	39	Exploits River Hydroelectric Generation Expansion	September 5, 2018	-	NL Hydro	-	MS Word
	40	System Adequacy Study Data Request – Hydro Expansion	2018	-	NL Hydro	-	MS Excel
	41	EXPLOITS RIVER HYDRO INVENTORY (1 p.)	Unspecified	-	Unspecified	-	PDF
	42	EXPLOITS RIVER POTENTIAL GENERATION SITES REVIEW	Unspecified	-	Unspecified	-	PDF

APPENDIX B

COST AND SCHEDULE CLASSIFICATIONS

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1. OVERVIEW

As part of the Generation Expansion Screening Study, cost estimates from 2018 were escalated to year-end 2022 for each of the prospects and overall project development timelines and construction schedules prepared. Classifications can be helpful in describing the level of accuracy and detail of cost and schedule estimates.

Cost estimates are typically classified using the AACE system (see below), with Class 5 being the lowest accuracy and preparation effort) and Class 1 being the highest accuracy and preparation effort.

Schedules, however, are typically classified by levels, starting with Level 1 (highest-level rollup of information) through to Level 5 or higher (very detailed information). Unlike the AACE system for cost estimates, schedule classifications are more subjective (see **SECTION 3.** below).

2. COST ESTIMATING CLASSES

Cost estimate classification is based on the Association for Advancement of Cost Engineering (AACE) *Cost Estimate Classification System*. In **TABLE B-1** below, the "Maturity Level of Project Definition Deliverables" aligns with the "% Complete" attribute used in the Gap Analysis.

Note that a Class 3 estimate has an End Usage of "Budget authorization or control", and is the minimum class usually required for Project Sanction (Gate 3) in the Decision Gate process (see **Main Report SECTION 3.2**).

TABLE B-1 AACE COST ESTIMATE CLASSIFICATION SYSTEM
(Recommended Practice No. 18R-97 Rev. August 7, 2020)

	Primary Characteristic	*Secondary Characteristic*			
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical +/- range relative to index of 1 (i.e. Class 1 estimate) [a]	**PREPARATION EFFORT** Typical degree of effort relative to least cost index of 1 [b]
Class 5	0% to 2%	Screening or feasibility	Stochastic (factors and/or models) or judgment	4 to 20	1
Class 4	1% to 15%	Concept study or feasibility	Primarily stochastic	3 to 12	2 to 4
Class 3	10% to 40%	Budget authorization or control	Mixed but primarily stochastic	2 to 6	3 to 10
Class 2	30% to 75%	Control or bid/tender	Primarily deterministic	1 to 3	5 to 20
Class 1	65% to 100%	Check estimate or bid/tender	Deterministic	1	10 to 100

Notes: [a] If the range index value of "1" represents +10/-5%, then an index value of 10 represents +100/-50%.
[b] If the cost index value of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%.

As per AACE, “Maturity Level of Project Definition Deliverables” is roughly indicated in Table B-1 by an approximate percentage of complete definition. However, it is the actual maturity of each deliverable that determines the overall maturity level of the estimate, not the percentage. This is best explained by AACE’s summary checklist of basic deliverables typically found in the energy industry, reproduced in **TABLE B-2** below. The “Maturity Level” is the approximate completion status of the deliverable expected in each Cost Estimate Class according to the following descriptors.

General Project Data

Not Required (NR) May not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.

Preliminary (P) Project definition has begun and progressed to at least an intermediate level of completion. Review and approvals for its current status has occurred.

Defined (D) Project definition is advanced, and reviews have been conducted. Development may be near completion with the exception of final approvals.

Technical Deliverables

Not Required (NR) Deliverable may not be required for all estimates of the specified class, but specific project estimates may require at least preliminary development.

Started (S) Work on the deliverable has begun. Development is typically limited to sketches, rough outlines, or similar levels of early completion.

Preliminary (P) Work on the deliverable is advanced. Interim, cross-functional reviews have usually been conducted. Development may be near completion except for final reviews and approvals.

Complete (C) The deliverable has been reviewed and approved as appropriate.

There will, of course, be other deliverables specific to the individual scopes of work for projects in Hydro’s portfolio. However, the list shown in Table B-2 is considered a good summary for the purposes of defining the level of Project Definition Maturity required to meet industry-standard “Pre-Sanction” requirements, i.e., at least a Class 3 estimate prior to Gate 3.

In situations where market conditions or technical uncertainty is high, it may be necessary to advance some deliverables to Class 2 standards. For example, it may be necessary to obtain bid pricing in order to reduce construction cost risk. This will require some deliverables, like earthworks, civil/structural, mechanical and/or electrical discipline drawings, to be near completion (i.e., Class 2 standard). The resulting “Maturity Level of Project Definition Deliverables” will, therefore, be approximately between Class 2 and Class 3 and the “% of complete definition” between Class 3: 10 to 40% and Class 2: 30 to 75%.

TABLE B-2 AACE MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES

(after AACE International Technical Paper TCM-3747, 2021)

MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES	ESTIMATE CLASSIFICATION				
	CLASS 5	CLASS 4	CLASS 3	CLASS 2	CLASS 1
	0% to 2%	1% to 15%	10% to 40%	30% to 75%	65% to 100%
GENERAL PROJECT DATA:					
A. SCOPE:					
Project Scope of Work Description	P	P	D	D	D
Site Infrastructure (Access, Construction Power, Camp etc.)	NR	P	D	D	D
B. CAPACITY:					
Facility Output / Production Profile	P	P	D	D	D
Electrical Power Requirements (when not the primary capacity driver)	NR	P	D	D	D
C. PROJECT LOCATION:					
Plant and Associated Facilities	P	P	D	D	D
D. REQUIREMENTS:					
Codes and/or Standards	NR	P	D	D	D
Communication Systems	NR	P	D	D	D
Fire Protection and Life Safety	NR	P	D	D	D
Environmental Monitoring	NR	NR	P	P	D
E. TECHNOLOGY SELECTION:					
N/A					
F. STRATEGY:					
Contracting / Sourcing	NR	P	D	D	D
Escalation	NR	P	D	D	D
G. PLANNING:					
Regulatory Approval & Permitting	P	P	D	D	D
Material Utilization (Borrow Sources)	P	P	P/D	D	D
Logistics Plan	P	P	P	D	D
Work Breakdown Structure	NR/P	P	P/D	D	D
Decommissioning Plan	NR	P	D	D	D
Integrated Project Plan[1]	NR	P	D	D	D
Project Code of Accounts	NR	P	D	D	D
Project Master Schedule	NR	P	D	D	D
Risk Register	NR	P	D	D	D
Stakeholder Consultation / Engagement / Management Plan	NR	P	D	D	D
Startup and Commissioning Plan	NR	P	P/D	D	D

Continued…

MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES	ESTIMATE CLASSIFICATION				
	CLASS 5	CLASS 4	CLASS 3	CLASS 2	CLASS 1
	0% to 2%	1% to 15%	10% to 40%	30% to 75%	65% to 100%
H. STUDIES:					
Hydraulics	P	P	D	D	D
Topography and/or Bathymetry	P	P	P/D	D	D
Environmental Impact / Sustainability Assessment	NR	P	D	D	D
Environmental / Existing Conditions	NR	P	D	D	D
Soils and Hydrology	NR	P	D	D	D
Geotechnical Investigation	NR	P	P/D	D	D
TECHNICAL DELIVERABLES:					
Block Flow Diagrams	S/P	C	C	C	C
Hydraulic Design and Probable Maximum Flood (PMF)	S	P	C	C	C
Equipment Datasheets	NR/S	P	C	C	C
Equipment Lists: Electrical	NR/S	P	C	C	C
Equipment Lists: Process / Utility / Mechanical	NR/S	P	C	C	C
Design Specifications	NR	S/P	C	C	C
Electrical One-Line Drawings	NR	S/P	C	C	C
General Equipment Arrangement Drawings	NR	S/P	C	C	C
Instrument List	NR	S/P	C	C	C
Construction Permits	NR	S/P	P/C	C	C
Civil / Site / Structural / Architectural Discipline Drawings	NR	S/P	P	C	C
Demolition Plan and Drawings	NR	S/P	P	C	C
Erosion Control Plan and Drawings	NR	S/P	P	C	C
Fire Protection and Life Safety Drawings and Details	NR	S/P	P	C	C
Mitigation Measures (Aquatic, Terrestrial, Avian, Clearing, Heritage etc.)	NR	S	P	C	C
Dam Design & Drawings	NR	S	P	P/C	C
De-Silting Basins	NR	S	P	P/C	C
Gates and Cranes Design & Drawings	NR	S	P	P/C	C
Intake Design & Drawings	NR	S	P	P/C	C

*The integrated project plan (IPP), project execution plan (PEP), project management plan (PMP), or more broadly the project plan, is a high-level management guide to the means, methods and tools that will be used by the team to manage the project. The term integration emphasizes a project life cycle view (the term execution implying post-sanction) and the need for alignment. The IPP covers all functions (or phases) including engineering, procurement, contracting strategy, fabrication, construction, commissioning and start-up within the scope of work. However, it also includes stakeholder management, safety, quality, project controls, risk, information, communication and other supporting functions. In respect to estimate classification, to be rated as defined, the IPP must cover all the relevant phases/functions in an integrated manner aligned with the project charter (i.e., objectives and strategies); anything less is preliminary. The overall IPP cannot be rated as defined unless all individual elements are defined and integrated.

Continued…

MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES	ESTIMATE CLASSIFICATION				
	CLASS 5	CLASS 4	CLASS 3	CLASS 2	CLASS 1
	0% to 2%	1% to 15%	10% to 40%	30% to 75%	65% to 100%
Penstock Design & Drawings	NR	S	P	P/C	C
Power House Design and Drawings	NR	S	P	P/C	C
Power Tunnel / Canal Design and Drawings	NR	S	P	P/C	C
Spillway Design & Drawings	NR	S	P	P/C	C
Turbine and Generator Design and Drawings	NR	S	P	P/C	C
Electrical Schedules	NR	NR/S	P	P/C	C
Instrument and Control Schedules	NR	NR/S	P	P/C	C
Instrument Datasheets	NR	NR/S	P	P/C	C
Spare Parts Listings	NR	NR	P	P/C	C
Electrical Discipline Drawings	NR	NR	S/P	P/C	C
Facility Emergency Communication Plan and Drawings	NR	NR	S/P	P/C	C
Information Systems / Telecommunication Drawings	NR	NR	S/P	P/C	C
Instrumentation / Control System Discipline Drawings	NR	NR	S/P	P/C	C
Mechanical Discipline Drawings	NR	NR	S/P	P/C	C
Auxiliary Electrical Design & Drawings	NR	NR	S	P	C
Auxiliary Mechanical Design & Drawings	NR	NR	S	P	C
Protection & Controls System Design & Drawings	NR	NR	S	P	C

3. SCHEDULE LEVELS

Terms like "Level 2 Schedule" and "L4 Schedule" are sometimes used as a general description of project planning maturity, but this can be misleading. Schedule levels have evolved as a description of (1) the audience for whom the schedule is intended and (2) the level of detail within the schedule structure itself (**TABLE B-3**).

- Level 1 and Level 2 schedules are usually developed as part of conceptual or pre-feasibility studies for Program Management and financial decision-making purposes.
- A Level 3 schedule is usually first developed as a high-level critical path overview of a project and, if the project is relatively small, a Level 3 schedule can be expanded into a Level 4 schedule for coordinating the execution of the works. On larger or more complex projects with multiple Level 4 schedules, the Level 3 schedule is maintained as the project's overall integrated schedule.
- Every project that moves into the execution stage (i.e., past Gate 3) should have a Level 4 schedule for day-to-day coordination of activities that supports the Path of Construction (construction sequencing), complete with a Critical Path. It is good practice to keep Level 4 schedules to a manageable size, focused on the work in one management area.
- Level 5 schedules are generally for short-term activities and are the end-product of Workface Planning (WFP), used at the field level to plan and execute work shifts for construction crews and for review at tailgate meetings.

Given the project planning maturity of the Generation Expansion prospects considered in this study, the overall project development timelines and schedules are generally Level 1 (L1) or Level 2 (L2).

TABLE B-3 SCHEDULE LEVEL DESCRIPTIONS

LEVEL	NAME	DESCRIPTION	MAIN AUDIENCE / USERS
L1	Milestone or Master Schedule	Typically one page and highlights major activities and key deliverables.	Owners, senior management, stakeholders, bidders
L2	Management Summary	Higher level summary of L3 activities according to the WBS (Work Breakdown Structure)	Project and program managers, project sponsors
L3	Project Coordination Schedule	Milestones and design, engineering, procurement, construction, commissioning and start-up	Project or program managers, construction managers, Owners
L4	Working Level Schedule	An expansion of L3, the key working level schedule by Work Package, usually developed by the contractor and with Critical Path established	Functional managers, discipline leads, project engineers, construction superintendents, foremen
L5	Detailed Schedule	An expansion of L4, used to plan day-to-day work for crews based on a 1- to 2-week look-ahead	Construction superintendents, general foremen, foremen, team members

APPENDIX C

PROSPECT OVERVIEWS, GAP ANALYSIS & RISKS

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APPENDIX C

PROSPECT 1

BAY d'ESPOIR HYDRO GENERATING UNIT 8

PROSPECT OVERVIEW, GAP ANALYSIS & RISKS

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1. PROSPECT 1 OVERVIEW: BDE UNIT 8

1.1. LOCATION AND BACKGROUND

Located in South Central Newfoundland (**FIGURE C1.1**), Bay d'Espoir Phase 1 consisted of six (6) x 75 MW turbine generating units in one (1) powerhouse completed in 1967.

Phase 2 consisted of a second powerhouse built to house one (1) x 150 MW generating unit ("Unit 7"), completed in 1977. The structure and tailrace were built to facilitate the extension of the powerhouse to accommodate Unit 8.

In 2018, Newfoundland and Labrador Hydro ("Hydro") commissioned SNC-Lavalin ("SLI") to study the addition of an eighth (8th) 150 MW generating unit ("Unit 8") by expanding the second powerhouse ("2018 SLI study").[1]

FIGURE C1.1 LOCATION AND EXISTING FACILITIES BAY D'ESPOIR

[1] *Bay d'Espoir Hydro Generating Unit 8 CLASS 3 COST ESTIMATE AND PROJECT EXECUTION SCHEDULE*. SNC-Lavalin Doc. 647756-0000-40ER-I-0002-00, March 22, 2018.

1.2. PROJECT DESCRIPTION

The proposed project consists of the following major facilities.

- Generation Facility
- Water Conveyance System
- Transmission Facilities

The Generation Facility consists of a new Powerhouse adjoined to existing Powerhouse 2, with a 150 MW Francis Turbine Generator, main transformer, isolated phase bus, auxiliary mechanical/electrical equipment, control and protection equipment, fire protection system, hydro-mechanical equipment, etc. The new unit will be built in the existing excavation, upstream of the Unit 8 Draft Tube Outlet, built as a part of the original Powerhouse No. 2.

The Water Conveyance System consists of an enlarged headrace channel, a new water intake resembling the Unit 7 intake, a new buried steel penstock, widening of the tailrace, and installation of further erosion protection in the tailrace channel.

Transmission Facilities consist of a 1.9 km high-voltage 230 kV line from Unit 8 step-up transformer to Terminal Station No. 2, plus modifications to Terminal Station No. 2 and a new sub-station. The new facility will utilize the existing powerhouse forebay and does not require the construction of any dams.

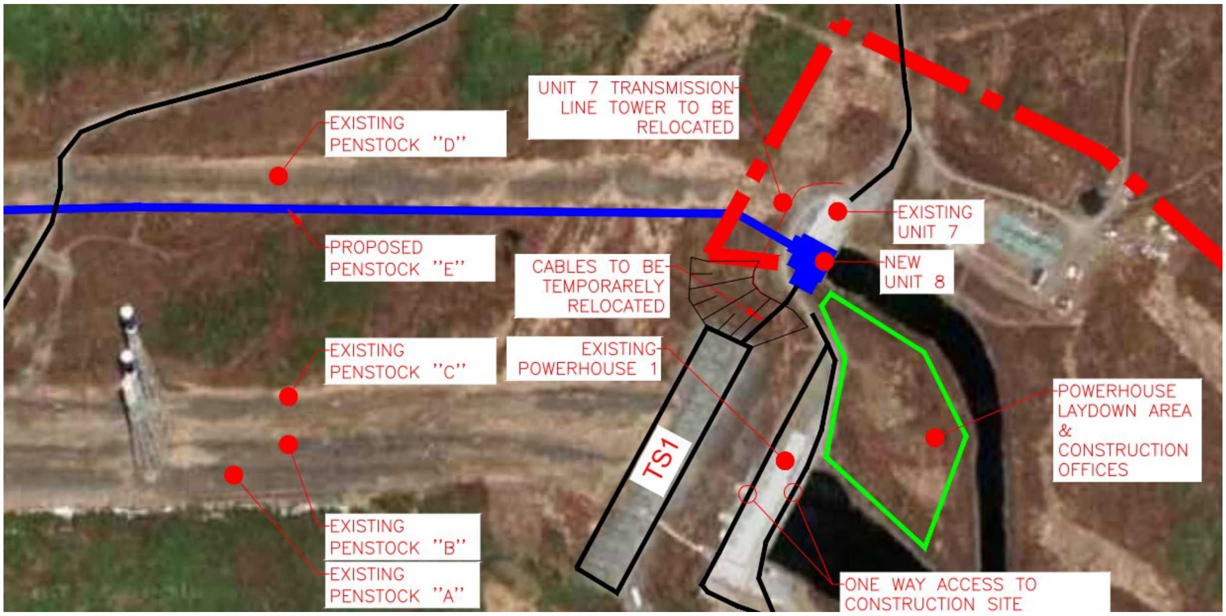
1.3. PROPOSED LAYOUT

The proposed layout for Unit 8 is reproduced in **FIGURE C1.2** below.

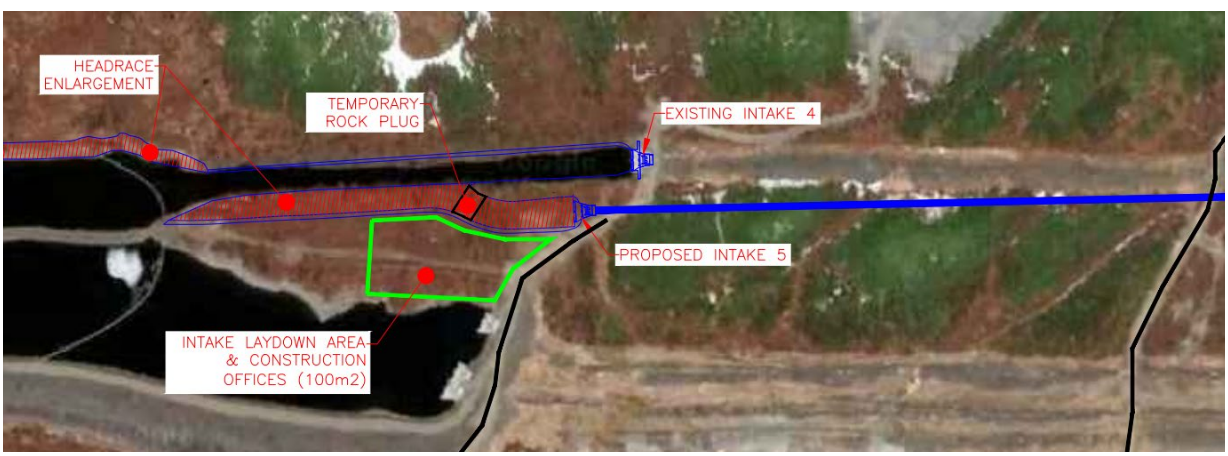
1.4. PROJECT EXECUTION TIMELINE

The Overall Development Timeline is based on a typical Brownfield project schedule basis and incorporates the project schedule provided in the 2018 SLI study and allowance of an additional 11 months for Long-Lead delivery times. One (1) year has been assumed for the Environmental Approval Process and total estimated project duration is 5.8 years.

A more detailed analysis of project timelines for Unit 8 was provided separately in the report *Bay d'Espoir Hydro Generating Unit 8 COMPARATIVE PROJECT SCHEDULES FOR ASSESSMENT OF CONTRACTING STRATEGY ALTERNATIVES*. SLI Document No. 691499-0000-40ER-I-0002 Rev PA, September 2022.



Powerhouse Extension & Penstock



Headrace, Intake & Penstock

FIGURE C1.2 PROPOSED LAYOUT FOR BAY D'ESPOIR UNIT 8
(from *Bay d'Espoir Hydro Generating Unit 8 CLASS 3 COST ESTIMATE AND PROJECT EXECUTION SCHEDULE*. SNC-Lavalin Doc. 647756-0000-40ER-I-0002-00, March 22, 2018.)

1.5. COST ESTIMATE TO BUILD PROJECT (ESCALATED TO YE-2022)

The 2018 cost estimate for Unit 8 was escalated to YE-2022 as shown in **TABLE C1-1**.

TABLE C1-1: UNIT 8 COST ESTIMATE ESCALATED TO YE-2022

COST ITEM	AMOUNT	NOTES
Direct Cost	$180,345,823	Material, labour, equipment, salaries, benefits, rentals, subcontractors, travel, etc.
Indirect Cost	$94,764,963	52% of Direct Cost
Contingency	$59,446,527	P- 80: 22.5% of Construction Cost
Escalation during Construction	$20,304,583	Average of 2.8% per year
Total Base Budget (2018)	$354,861,896	
Capitalized Interest	$30,806,789	@ 6.41% per year
Total Cost (2018)	$393,668,684	
Escalation calculation (2018-2022)	132.5%	2019: 2.2% 2020: 1.2% 2021: 11.4% *Statistics Canada Construction Cost Index (CCPI)*
		2022: 15% *Projection by SLI Cost Estimating Department*
2022 TOTAL ESCALATED COST	**$521,637,506**	
AACE Estimate Accuracy (Index of 1 = +10% / -5%)	+40% / -20%	Class 3 accuracy index range = 2 to 6 Index for this estimate assumed = 4

1.6. KEY TECHNICAL METRICS

The following metrics were developed from the above information for the Screening and Ranking Process.

- Power (MW Installed): One (1) x 150 MW Francis Turbine Generator
- Cost per MW of Power (escalated to YE-2022): $3.5 million / MW
- Overall Project Duration : 5.8 Years
  - Planning Timeline: 2.3 Years
  - Execution (Construction) Timeline: 4.5 Years
  - Less Overlap Planning/Execution: -1.0 Year
  - Overall Development Timeline: 5.8 Years

2. EXISTING PROJECT INFORMATION DATA GAP

2.1. OVERVIEW

By definition, a "Gap Analysis" is the comparison of a "current state" against a "future state" or "desired state". For this study, a Gap Analysis was performed to identify differences between the "current state" of Project Planning maturity against the "desired state" of Project Planning maturity required to meet industry standard.

Two (2) key deliverables from the SLI study were used as a basis for this Gap Analysis, as follows.

- Hydraulic Analysis of Water Conveyance System
- Class 3 Cost Estimate and Project Execution Schedule

Also considered was the Hydrology and Feasibility Study for Potential Bay d 'Espoir Hydroelectric Generating Unit No. 8 (Hatch, 2020). All relevant documents are listed in **APPENDIX A** to the main report.

SECTION 3.3 of the Main Report summarizes the deliverables, by discipline, necessary to complete *Front-End Execution Planning (FEEP)* for a project of this nature. This level of planning is considered the industry standard for investment decision making. This section compares the existing project documentation to that of a FEEP-level requirement and identifies the data gaps. Data Gap

2.2. DATA GAP

The 2018 work by SLI was to define the project and estimate the costs and timeline to execute. To advance this work to a *Front-End Execution Planning (FEEP) standard*, the following gaps remain (see **TABLE C1-2**).

TABLE C1-2: GAP ANALYSIS FOR PROSPECT 1: BDE UNIT 8

STAGE 1: PROJECT DEFINITION		
RESPONSIBLE GROUP	**DELIVERABLE**	**REQUIREMENTS TO ADDRESS GAP**
Owner / Corporate	**PROJECT DEFINITION STATEMENT**	Complete
	PROJECT CHARTER	Develop Project Charter as per standard for internal approval and sign-off, including recommended Contracting Strategy. Develop the Environmental Management Strategy. Approve FEEP-Stage Budget, Deliverables List, and Milestone Schedule.
STAGE 2: FEEP		
RESPONSIBLE GROUP	**DELIVERABLE**	**REQUIREMENTS TO ADDRESS GAP**
Project Management	**PROJECT EXECUTION PLAN (PEP)**	
	Scope of Work	Based on the Scope of Work outlined in existing documentation, and the design optimizations to be prepared, prepare an updated Project Scope of Work Document (SOW) and Work Breakdown Structure (WBS).
	Project Management Strategy	Key elements of the execution strategy will need to be reviewed and updated based on the selected Project Delivery Model.
	Project Controls Strategy	Determine how cost estimating and schedule development activities are going to be coordinated.
	Health & Safety Strategy	Prepare HS&S Project Strategy.
	QA / QC Strategy	Prepare Quality Management Strategy.
	PROJECT CONTROLS DOCUMENTATION	
	Cost Estimate (Class 4 / Class 3)	Update Cost Estimate based on updated Contracting Strategy, Schedule, Design Optimizations, updated Unit Costs and costs for Long-Lead Items, and the cost of implementing the Environmental Protection Plan. Prepare Monte Carlo Simulation.
	Schedule	Prepare Level 2 (L2) Schedule based on Updated MTOs, Timelines for Long-Lead Items, Environmental Timelines, Construction Sequencing, and Contracting Strategy.

Environmental Management	**ENVIRONMENTAL MANAGEMENT PLAN**	Based on the Environmental Management Strategy, develop a detailed Management Plan.
	PROJECT REGISTRATION / EIS	Identify key concerns, conduct Field Investigations, identify impacts and mitigations, prepare and submit Project Registration.
Engineering	**FACILITY SCOPE OF WORK**	Based on the Design Optimizations (Line 18), and revised MTOs, update the Scope of Work for each Facility.
	PRELIMINARY ENGINEERING	Review the 2018 preliminary designs and finalize the scope of work for the field program.
	FIELD INVESTIGATIONS SOW	Define a detailed Scope of Work for the Field Investigation Program.
	DESIGN OPTIMIZATIONS	Optimize the 2018 preliminary designs based on results of the Field Investigation Program.
	UPDATED PRELIMINARY ENGINEERING	Complete preliminary design based on the optimizations.
	MTOs	Update the Facility MTOs and the quantities in the cost estimate and schedule duration calculations, based on updated Preliminary Engineering.
Supply Chain Management	**CONTRACTING STRATEGY**	Based on Hydro's selected Contracting Strategy, prepare a Project Contracting Strategy document, identify standard contract documentation and procurement processes.
	BID & EVALUATION PLAN	Prepare a plan which documents standard contract documentation and the bid management process, including bid evaluation plans, approval authorities, etc.
	LONG-LEAD ITEMS VENDOR PACKAGES	Co-ordinate Vendor Packages based on Engineering input.
	FIELD INVESTIGATIONS PLAN	Authorize the Field Investigation Program.
Construction	**CM STRATEGY**	Prepare a Field Investigation Program Execution Plan based on the Scope of Work prepared by engineering. Prepare Construction Management Plan based on the Contracting Strategy.
	PATH OF CONSTRUCTION	Undertake Construction Planning activities necessary to develop the Path of Construction (sequencing).
	CONSTRUCTION SCHEDULE	Based on the Path of Construction, update construction schedule.

3. SCOPE OF WORK TO COMPLETE FEEP STAGE

3.1. PURPOSE

This section outlines the scope of work ("SOW") necessary to advance the 2018 SLI study to meet industry-standard FEEP-level documentation requirements for this prospect, including updates to cost and schedule.

3.2. OWNER'S KEY INPUTS

At the start of the FEEP stage, it is recommended that the Owner provide the Project Team(s) with a Project Charter, approved Environmental Management Strategy, and approved FEEP Stage Budget, Deliverables List and Milestone Schedule.

In addition, if time is of the essence, both the Owner and Project Team(s) could, during the standard Public Utilities Board ("PUB") review, jointly undertake the risk mitigation proposals in **SECTION 5**.

3.3. PROJECT DEFINITION STATEMENT UPDATE SCOPE OF WORK

The BDE Unit 8 prospect will not require an update to the Project Definition Statement. (All other prospects will require an update.)

3.4. PROJECT TEAM FEEP-STAGE SCOPE OF WORK

3.4.1. Project Management Discipline

The key Project Management Team deliverable is a _Front-end Execution Plan (FEEP)_, which incorporates the following key documentation.

- Based on the scope of work outlined in existing documentation, and the design optimizations to be prepared (see **3.3.3. Engineering** below), prepare an updated _Project Scope of Work Document (SOW)_ and _Work Breakdown Structure (WBS)_.
- Based on the updated scope of work, prepare a Front-End Execution Plan (FEEP). Key aspect of the FEEP is the contracting strategy which details the project delivery model, compensation model, and sourcing strategy.
- Based on the SOW and WBS, develop the following key sections of the FEEP:
  - Project Management Approach
  - Project Controls Strategy
  - Health, Safety and Security
  - Quality Management Strategy
- Coordinate the preparation of the following by other disciplines.
  - Environmental Management Plan
  - Engineering Management Plan
    - Procurement Management Strategy
    - Contracting Strategy
    - Construction Management Strategy
    - Construction Sequencing Plan

- Work Packaging Plan

- Coordinate the preparation of the following Project Controls Documentation.
- Using the existing schedule data, revised WBS and Work Packaging Plan, develop and optimize a *L3 Project Schedule and Schedule Basis*, incorporating EIA and Long-Lead timelines provided by vendors. The *Level 3 (L3) Project Schedule should include*:
  - L4 Project Management Schedule and Schedule Basis
  - L4 Environmental Management Schedule and Schedule Basis
  - L4 Engineering Management Schedule and Schedule Basis
  - L3 Bid Stage Schedule and Schedule Basis
  - L3 Construction Schedule and Schedule Basis with Monte Carlo Simulation which incorporates updated Long-Lead Items delivery timelines
  - L4 Field Investigation Plan and Schedule Basis
- *Class 3 Cost Estimate, Estimate Basis, and Risk Analysis*, e.g., Monte Carlo Simulation. Update the existing Cost Estimate based on updated WBS / Work Package Plan, the facility optimizations, and revisions to the indirect scope of work, plus updated unit, and material / equipment cost.

Note: At the present stage of planning, the following key timelines and impacts remain unknown.

- Environmental Approval Process and relates impacts on cost and schedule.
- Owner's Planning and Approval Process.
- Detailed Engineering Resource availability.
- Major Equipment availability and cost.

3.4.2. Environmental Discipline

The Environmental discipline shall:

- Prepare an Environmental Management Plan.
- Prepare a robust Environmental Registration Document.

3.4.3. Engineering Discipline

The engineering discipline shall:

- Prepare a *Scope of Work for Field Investigation Program* for immediate execution by Construction, including the preparation and submission of applications for permits to carry out the field work.
- Prepare and implement an *Engineering Management Plan*, including *L4 Engineering Schedule and Schedule Basis*.

Key Engineering activities to be undertaken are:

- Interpretation and reporting of the field investigation results.
- Preparation (review and update) of vendor packages for the Long-Lead Items.
- Undertake Design Optimizations as recommended in the SLI 2018 Class 3 Cost Estimate and Project Execution Schedule report, which include:

- Hydraulic design of the headrace and tailrace canals and finalize the preliminary designs, including cost and schedule updates.
- Selection of:
  - Intake location.
  - Penstock route and excavation quantities.
- Finalize design of the Vent shaft and Gate shaft.
- Determine site access during construction.
- Determine temporary relocation of underground cables.

- Update existing scope of work information and prepare a Facility Scope of Work document.
- Update existing preliminary designs and develop into preliminary engineering work packages, by discipline, including updated MTOs. The EWPs shall support the Work Packaging Plan.
- Assess the impacts of the construction activities on operations and work with the Owner's operations team to develop mitigations.

3.4.4. Procurement Discipline

The Procurement discipline shall prepare and implement a *Procurement Management Plan*, Key procurement activities are:

- Working with the Owner to finalize standard contract documentation and procurement processes.
- Working with Project Management and Construction disciplines to document Contracting Strategy.
- Preparation of a L3 Bid Schedule and Schedule Basis.
- Issue vendor packages and obtain quotations / delivery timelines for Long-Lead Items.
- Prepare and issue POs for Field Program.

3.4.5. Construction Discipline

The construction discipline shall prepare a Field Investigation Program Execution Plan, based on the scope of work provided by engineering. The plan shall include:

- L4 Field Investigation Schedule and Basis
- Class 2 Field Investigation Cost Estimate and Basis
- Upon approval, execute the field investigation program, with function management from engineering.

The Construction team shall prepare and implement a *Construction Management Plan*. Key aspects of the plan shall include:

- Define the Path of Construction[2] and optimize the construction sequencing.
- Prepare the L3 Construction Schedule and Basis.

[2] The Path of Construction is defined as the optimal sequencing of the building of a facility, developed by Construction, Engineering and Project Management Subject Matter Experts (SMEs), typically working backwards from the "end state".

- Prepare a plan for monitoring and control of construction contractor activities.
- Review and update the indirect direct scope of work to reflect current market conditions and the selected project delivery model.
- Work with the Owner to develop mitigations to minimize the impact of construction activities on existing operations.

4. PROJECT-SPECIFIC RISKS

4.1. ENVIRONMENTAL RISK

A review of the federal and provincial Environmental Regulatory and Approval context for the proposed NL Hydro Generation Expansion Prospects is included in **APPENDIX D**.

4.2. SOCIOECONOMIC INFLUENCES

Socioeconomic influences for the proposed Prospects are also discussed in **APPENDIX D**.

4.3. MARKET CONDITIONS

As this could be the province's first major (hydro) project since Muskrat Falls, interest from local bidders and local labour group will be high, which is a positive factor. However, the project will also be a test case for the post-pandemic cost environment in the province, costs may be challenging to forecast.

4.4. LONG-LEAD ITEMS RISK

The turbine generator and related major equipment are considered Long-Lead items. Current market conditions and other supply chain management challenges are anticipated to add eleven (11) months to the schedule that was developed in the 2018 SLI study.

4.5. TECHNICAL RISK

This section presents risks that have been identified in previous reports and from SLI experience with similar hydroelectric developments.

4.5.1. Hydrotechnical

The hydrology was studied in 2020 by Hatch and is considered up to date. However, the study did not investigate the potential long-term impact from climate change. Since Unit 8 will be mainly used to add capacity to the existing facility, the design may not be affected by climate change issues but should be considered.

Optimization of the operating pattern of Units 7 and 8 should be undertaken. A risk of vortexes at the intake, with possible air entrainment, was identified in previous studies.

CFD modeling (Flow-3D) of the intake is required to optimize the geometry and operational parameters. This was not previously undertaken because it requires updated topographical and bathymetric information.

Previous studies identified the costs and benefits of widening of tailrace to minimize head losses when the new unit is added. If not done, there will be an increase in head losses and loss of revenue for the facility.

A risk of overpressure in the penstock was also identified. This can be mitigated through design of the penstock and installation of a pressure relief valve, rather than installation of a surge tank. Previous studies recommended that studies be undertaken to optimize the design and wicket gate closing time, which could lead to cost savings by eliminating the need for a pressure relief valve.

4.5.2. Geotechnical

Previous studies identified that there is risk from geotechnical uncertainty. In particular, this applies to the penstock route and intake siting. The need for a geotechnical Field Investigation Program was identified and should be undertaken to mitigate this risk and to allow optimization of intake location and penstock profile, and to provide a better estimate of excavation quantities that will be required. The Field Investigation Program would also include bathymetry and topography.

The rock excavation for the new powerhouse was undertaken during the construction of the powerhouse for Unit 7. There is a risk that additional excavation may be required, but optimization of the powerhouse design should take the existing geometry into account to minimize that risk. Currently, only a relatively small amount of excavation would be required for the oil separator sump and a new service bay. If significant additional excavation is required, blast vibrations that could interfere with Unit 7 operation. This would have to be monitored and duly mitigated.

A source of aggregate materials for construction (e.g., penstock backfill, etc.) was identified at a location approximately 35 km from the site. This source should be confirmed for availability and its ability to provide suitable materials.

A rock plug will be used as part of the intake construction and the Field Investigation Program should verify that rock quality is acceptable for this purpose. The program will also help finalize the location of the plug.

4.5.3. Technical Complexity

Generally, from a design and construction perspective, the project is not technically complex. However, there are a few issues worth noting, as follows.

When the Powerhouse for Unit 7 was built in 1977, rock excavation for Unit 8 was undertaken, as well as the concrete work for the Draft Tube outlet such that the adjacent tailrace area could be excavated. Based on the limited as-built information available, additional scope may be the result once the excavation is completed. If additional rock excavation is required, the operation of Unit 7 will be affected. Blast vibrations will also need to be mitigated (see **Section 4.5.2**).

For a turbine generator of this size, model testing will be required. Due to the preconstruction of the Draft Tube of Unit 8, outlet geometry has been established, which may limit optimization of the turbine design.

Site access will be limited by the Unit 8 addition and further complicated by cable trays and other electrical component adjacent to the proposed powerhouse.

Even though the project is not technically complex, management of the interfaces will be key to schedule and cost control should multiple contractors be used.

All construction traffic will need to go over the Powerhouse 1 tailrace deck (single lane, load limit 15 t) and this will present clearance constraints and logistics difficulties. To help with clearances, relocation of the cable trays at P/H 1 should be studied.

Venting of the penstock during filling is a risk at many powerhouses. Limiting air velocities will be required to prevent damage, especially during emergency de-watering. This was previously identified in the study with comments about combining air vent and gate shaft to be reviewed at design.

The study included a reference to higher grade steel available today that could allow for reduction in thickness of penstock steel for the design. However, availability may be affected by supply chain issues and market conditions may drive costs higher.

A concrete wall is required between Unit 7 penstock and the new penstock to prevent destabilization of Unit 7. This wall will be important to maintaining Unit 7 in operation during construction and care should be taken in its location and installation. The Field Investigation Program should verify that there is sufficient information available to design this wall.

The original plan during Unit 7 construction was that Unit 8 would use the same service bay. The study identified/recommends an additional service bay to advance the schedule by provision of adequate space for assembly and erection of Unit 8. This approach also mitigates interference with Unit 7 maintenance, if required.

New stoplogs will be required for Unit 8 to allow for maintenance on Unit 7 if required during construction.

Overhead travelling crane rails will be extended from Unit 7 so the existing crane can be used. It needs to be verified that the crane is fully operational, is in good condition and has sufficient capacity for this purpose. Usually, heaviest lifts are seen during construction and cranes see limited service thereafter.

It should be verified that any systems that will make use of equipment or space in Unit 7 will be workable, e.g., jockey pump for fire water pressure and drainage into Unit 7 sump pit. Other construction logistics considerations include the provision of potable water, wastewater treatment, 24 kV emergency power, and telecommunication provided from Unit 7 P/H without interrupting that operation.

Existing embedded parts for draft tube gates will need to be verified that they are in good condition.

Electrical grounding of the new system needs to be reviewed. Previous reports contain reference to an ungrounded station service system and recommend that it be upgraded to current Hydro standards.

The selected transmission line route appears to cross multiple other existing facilities, but this could be examined further to see if the route could be made more efficient (e.g., can existing cut lines be used?).

Owner's Costs were provided by NL Hydro for the cost estimate in the 2018 SLI study. There is a list of assumed items included that should be verified and Hydro costs revisited for update.

4.6. PROJECT COST RISK

Given the global supply chain challenges, the largest risk factors to schedule and cost will be the variable cost of fuel and contractor capacity limitations (availability of human resources, both technical and trades).

4.7. PROJECT SCHEDULE RISK

Using a Modified EPCM schedule, the critical path for the planning stage is Cost and Schedule Update (schedule line-item BDE L2.1), specifically the Field Investigation Program, which is a prerequisite to design optimizations and MTO revisions (and, thus, cost and schedule). This assumes that the Owner has completed the activities in schedule line-item BDE L2.02 and assumes that the Detailed Execution Planning (DEP) Stage starts immediately following BDE L2.1.

5. MINIMUM WORK REQUIRED TO UPDATE COST AND SCHEDULE

5.1. PURPOSE AND OBJECTIVE

The SOW required to complete Front-End Execution Planning (FEEP) is outlined in **SECTION 3** above. It should be noted that the most accurate cost and schedule estimate would be attained by completed the full FEEP scope. However, for the BDE Unit 8 Prospect, Hydro requested that the study estimate the minimum level of work required to update cost and schedule and still meet Gate 3 (Project Sanction) requirements.

The FEEP stage was not fully completed in the 2018 SLI study and the information it was based on is now four (4) years old. This increases the schedule and financial risk associated with the accuracy of the escalated cost estimate. These risks can be mitigated by finalizing certain key decisions by the Owner and updating/completing the schedule and cost estimate from the previous 2018 SLI study.

5.2. KEY OWNER DECISIONS REQUIRED

The following key decisions by the Owner are required to advance the work to Gate 3.

1. Specification of Hydro's key objectives (in the Project Charter) related to:
    1.1. Cost
    1.2. Schedule
    1.3. Sanction Parameters
        1.3.1. What conditions must be meet before significant contractual commitments are made?
2. Selection of a Contracting Strategy[3], which consists of making recommendations on:
    2.1. Project Delivery Method
    2.2. Compensation Method(s)
    2.3. Sourcing Strategy
3. Turbine Generator
    3.1. Timing of the selection of a supplier and authorization to proceed with model testing.
4. Environmental Management
    4.1. Preparation of an Environmental Management Strategy including milestone date for Registration of the Project.

5.3. REQUIREMENTS FOR UPDATING / COMPLETING THE 2018 FEEP STUDY

1. Undertake Field Investigation Program
    1.1. Topographic and Bathymetric Surveys
    1.2. Geotechnical Investigations
2. Optimize Preliminary Designs based on the Field Data
3. Obtain Quotations and Delivery Timelines for W2W Packages

[3] See COAA Best Practice *Developing a Contracting Strategy* (March 2018).

4. Prepare Construction Sequencing Plan, a precursor to the full Path of Construction to be prepared in Detailed Execution Planning (DEP) Stage
5. Update Cost and Schedule

5.4. TIMING CONSIDERATIONS

Updating/completing the schedule and cost estimate would take approximately six (6) months, which includes three (3) months for a Field Investigation Program. *(Note: the Field Program should be executed between the months of April and November.)* Carrying out this work during the PUB review period, for example, would result in a six (6) month reduction in project schedule, allowing the Detailed Execution Planning (DEP) Stage to begin immediately after PUB approval.

APPENDIX C

PROSPECT 2

ADDITION OF A THIRD GENERATING UNIT CAT ARM

PROSPECT OVERVIEW, GAP ANALYSIS & RISKS

TABLE OF CONTENTS

1. PROSPECT 2 OVERVIEW: CAT ARM ADDITION

1.1. LOCATION AND BACKGROUND

Located in the southeastern section of the Great Northern Peninsula, north of Jacksons Arm, the existing Cat Arm Generation Facility consist of a Powerhouse with two (2) x 68.2 MW hydroelectric generating units. In 1985, ShawMont Newfoundland Limited was commissioned by NL Hydro to prepare a cost estimate for a third unit as an extension to the existing powerhouse in Cat Arm ("Cat Arm Addition")[1]. The scope of the study included the following.

- Review of the adequacy existing canals and tunnel system to support a third unit.
- Review of electrical and mechanical systems to ascertain the extent of modifications and extensions.
- Prepare conceptual layouts.
- Prepare project schedule and cost estimate.
- Identify the need for further studies and field investigations.
- Estimate the benefits that would be realized by reduction of spill.

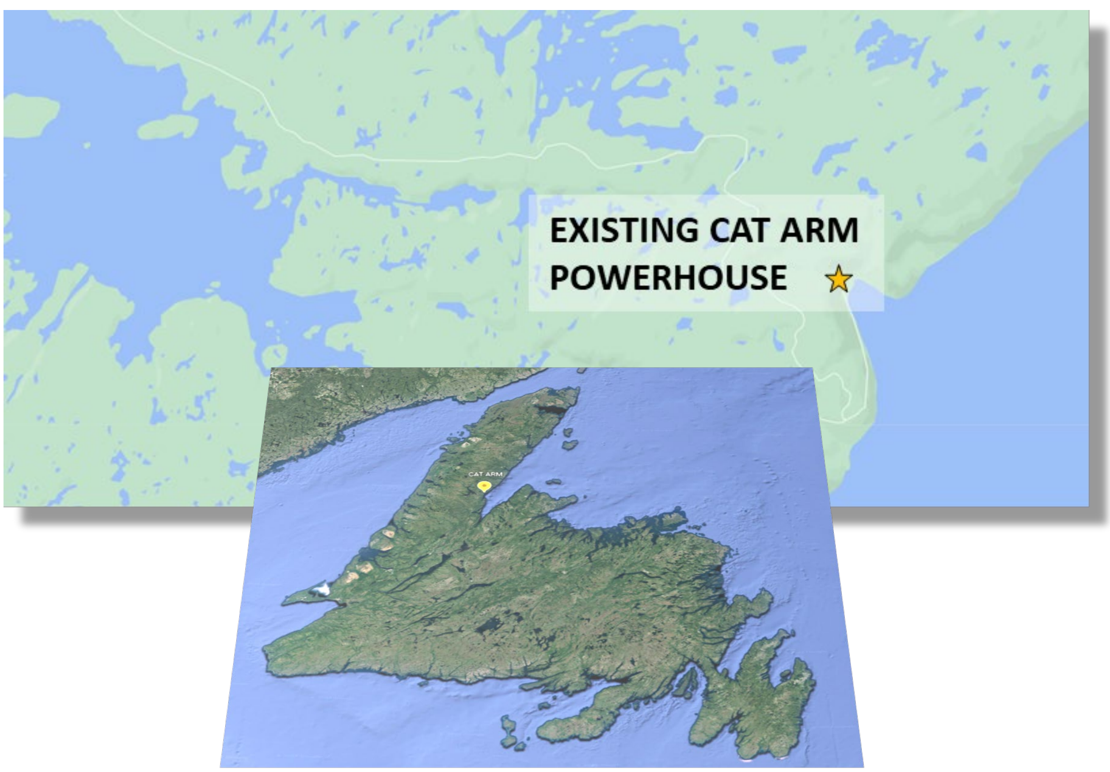


FIGURE C2.1 LOCATION MAP CAT ARM

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[1] *CAT ARM DEVELOPMENT ADDITION OF UNIT # 3*. Shawmont Report No. SMR-30-85, September 13, 1985

1.2. PROJECT DESCRIPTION

Provision of a third unit with all major equipment similar to existing Units 1 and 2. Major equipment includes a new Pelton Turbine, Generator and Power Transformer.

Additional Facilities include:

- 2.1 m diameter Steel Penstock x 459 m long
- 30 m of new tunnel
- Extension to powerhouse
- Mechanical and Electrical Services including control system, and 230 kV switchgear
- New channel to Tailrace

1.3. PROPOSED LAYOUT

The proposed layout for the Cat Arm addition is reproduced in **FIGURE C2.2** below.

An alternate layout based on having a separate powerhouse in front of the high-pressure Adit Portal was considered. This alternative would simplify foundation excavation and eliminate tunnel construction. However, it would require complete duplication of mechanical and electrical auxiliaries, a larger powerhouse, a longer penstock, and a new tailrace and was not recommended in the 1985 study. A key selection parameter was the assumption that equipment, controls, and layout for Unit 3 would be identical to units 1 and 2. Today, this assumption may not be applicable and as such the two options should be reassessed.

1.4. KEY TECHNICAL METRICS

The following metrics were determined and used in the Screening and Ranking Process.

- Power (MW Installed): One (1) x 62.2 MW Pelton Turbine
- Cost per MW of Power (escalated to YE-2022): $4.5 million / MW
- Overall Project Duration : 5.2 Years
  - Planning Timeline: 2 Years
  - Execution (Construction) Timeline: 3.2 Years
  - Less Overlap Planning/Execution: 0 Years
  - Overall Development Timeline: 5.2 Years

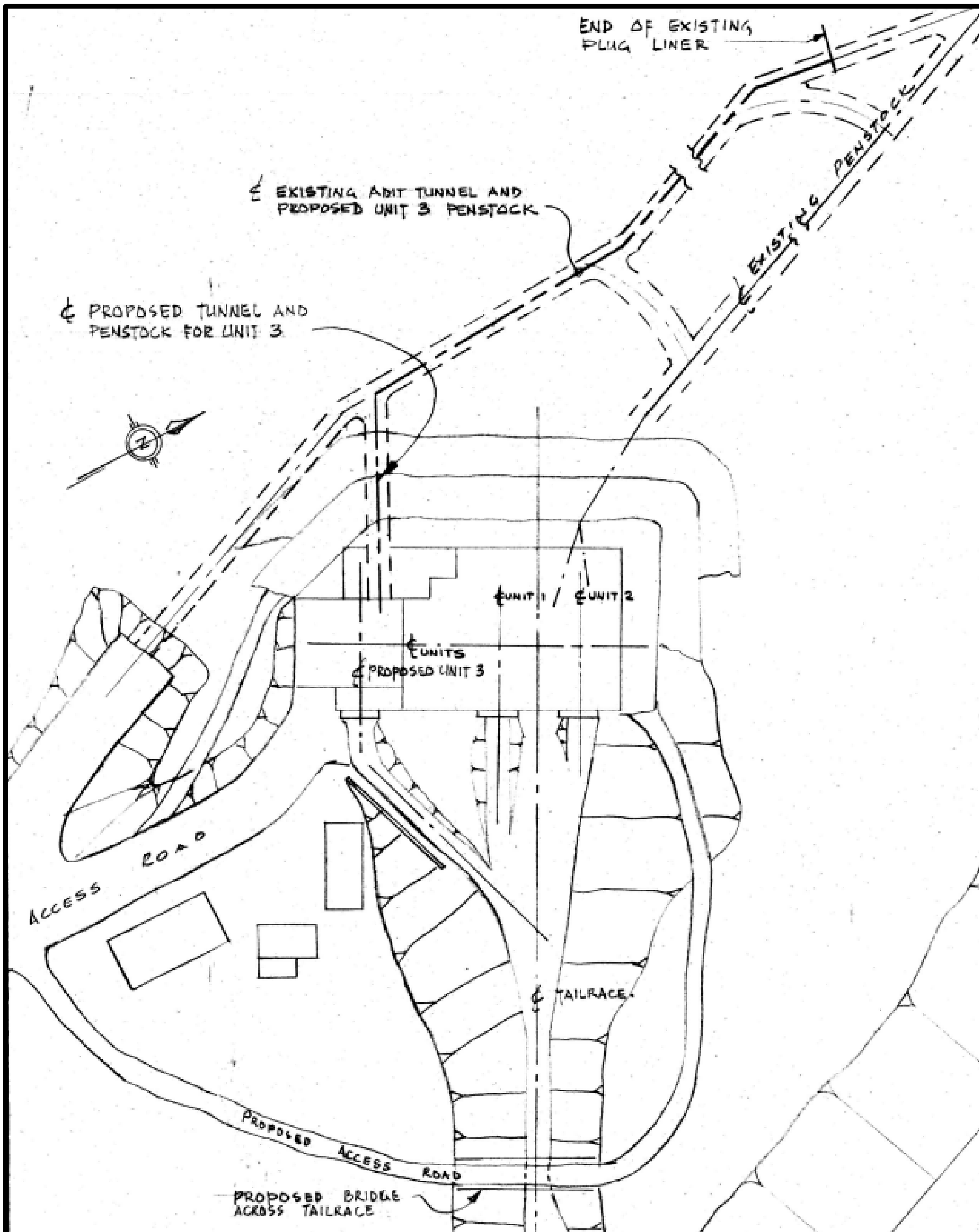

FIGURE C2.2 PROPOSED LAYOUT FOR CAT ARM ADDITION
(from *CAT ARM DEVELOPMENT ADDITION OF UNIT # 3*.
ShawMont Report No. SMR-30-85, September 13, 1985)

1.5. COST ESTIMATE TO BUILD PROJECT (ESCALATED TO YE-2022)

The 1985 cost estimate for the Cat Arm Addition was updated for Hydro in 2018 and was escalated to YE-2022 as shown in **TABLE C2-1**.

TABLE C2-1: CAT ARM ADDITION COST ESTIMATE ESCALATED TO YE-2022

COST ITEM	AMOUNT	NOTES
Direct Costs	$119,789,380.00	Tunnel excavation, penstock, powerhouse & tailrace, Pelton turbine, generator, switchyard and supporting equipment/infrastructure
Contractor's Indirects and General	$23,957,876.00	Overhead (staff and supervisory), mob/demob, temporary site facilities, site services, construction camp and subsistence.
Project Management / Engineering	$21,562,088.40	
Owner's Cost	$5,749,890.24	
Environmental & Regulatory	$750,000.00	
Interest	$16,550,263.14	
Contingency	$34,361,853.45	
Subtotal Cost (2018)	$222,721,351.23	
Other	$7,119,581.77	Unspecified (delta added to reconcile Subtotal with Total Cost below)
Total Cost (2018)	$229,840,933	
Escalation calculation (2018-22)	132.5%	2019: 2.2% 2020: 1.2% 2021: 11.4% *Statistics Canada Construction Cost Index (CCPI)*
		2022: 15% *Projection by SLI Cost Estimating Department*
2022 TOTAL ESCALATED COST	**$ 304,539,236**	
AACE Estimate Accuracy (Index of 1 = +10% / -5%)	+50% / -25%	Class 4 accuracy index range = 3 to 12 Index for this estimate assumed = 5

2. EXISTING PROJECT INFORMATION DATA GAP

2.1. OVERVIEW

While the 1985 report was called a “Feasibility Study”, it was essentially a cost and schedule determinization. Given this fact, and the age of the report (35+ years), it is recommended that the report be considered a Project Definition document.

2.2. DATA GAP

A complete review and update of the Project Definition document, followed by FEEP-level documentation, is recommended. The updated project definition should be based on updated hydrological data and recalculated power and energy availability, including selection of the Turbine Generator unit and related equipment. Included in this stage should be the Project Registration for the Environmental Assessment process plus the planning and execution of the Field Investigation Program.

During the FEEP, the two (2) options for the location of the powerhouse should be revisited.

To advance this work to a *Front-End Execution Planning (FEEP) standard*, the following gaps remain (see **TABLE C2-2**).

TABLE C2-2: GAP ANALYSIS FOR PROSPECT 2: CAT ARM ADDITION

STAGE 1: PROJECT DEFINITION		
RESPONSIBLE GROUP	**DELIVERABLE**	**REQUIREMENTS TO ADDRESS GAP**
Owner / Corporate	**PROJECT DEFINITION STATEMENT**	Update Hydrology, then identify Power / Energy options, select preferred option, identify benefits if there is a reduction in Spill. Gather as-built information and original design information. Assess if upgrades are required. Desktop study to document environmental impacts (no field studies required). Plan and implement a Field Investigation Program. Update Project Scheme, prepare Class 5 schedule and cost estimate.
	PROJECT CHARTER	Develop Project Charter as per standard for internal approval and sign-off, including recommended Contracting Strategy. Develop the Environmental Management Strategy. Approve FEEP Stage Budget, Deliverables List, and Milestone Schedule.

STAGE 2: FEEP		
RESPONSIBLE GROUP	**DELIVERABLE**	**REQUIREMENTS TO ADDRESS GAP**
Project Management	**PROJECT EXECUTION PLAN (PEP)**	
	Scope of Work	Update based on optimized preliminary designs.
	Project Management Strategy	Key elements of the execution strategy will need to be reviewed and updated based on the selected Project Delivery Model.
	Project Controls Strategy	Determine how cost estimating and schedule development activities are going to be coordinated.
	Health & Safety Strategy	Prepare HS&S Project Strategy.
	QA / QC Strategy	Prepare Quality Management Strategy.
	PROJECT CONTROLS DOCUMENTATION	

	Cost Estimate (Class 4 / Class 3)	Update Cost based on updated contracting strategy, schedule, design optimizations, updated unit costs and costs for Long-Lead items, and the cost of implementing the Environmental Protection Plan.
	Schedule	Prepare L2 Schedule based on Updated MTOs, Timelines for Long Lead Item, Environmental Timelines, Construction Sequencing, and Contracting Strategy.
Environmental Management	**ENVIRONMENTAL MANAGEMENT PLAN**	Based on the Environmental Management Strategy, develop a detailed Management Plan.
	PROJECT REGISTRATION / EIS	Prepare Robust Environmental Registration Document
Engineering	**FACILITY SCOPE OF WORK**	Update Scope of Work documentation based on optimized preliminary designs
	PRELIMINARY ENGINEERING	Prepare Vendor Packages for the Long-Lead Items. Undertake Preliminary Engineering.
	FIELD INVESTIGATIONS SOW	Completed in the Project definition Stage.
	DESIGN OPTIMIZATIONS	Based on the field data, optimize the preliminary designs, including assessment of both powerhouse location options.
	UPDATED PRELIMINARY ENGINEERING	Develop the optimized design into preliminary EWPs, including updated MTOs.
	MTOs	Update the MTOs based on the optimized design.
Supply Chain Management	**CONTRACTING STRATEGY**	Work with PM and Construction discipline to document the Contracting Plan.
	BID & EVALUATION PLAN	Prepare a plan which documents standard contract documentation, the bid management process, including bid evaluation plans, approval authorities, etc..
	LONG-LEAD ITEMS VENDOR PACKAGES	Issue vendor packages and obtain quotations / delivery timelines for Long Lead Items.
	FIELD INVESTIGATIONS PLAN	Issue PO for Field Investigation Activities.
Construction	**CM STRATEGY**	Prepare Construction Management Plan based on the Contracting Strategy.
	PATH OF CONSTRUCTION	Undertake Construction Planning activities necessary to develop the Path of Construction (sequencing).
	CONSTRUCTION SCHEDULE	Based on the Path of Construction, update construction schedule.

3. SCOPE OF WORK TO COMPLETE FEEP STAGE

3.1. PURPOSE

This section outlines the scope of work necessary update the Project Definition documentation for this project and to prepare FEEP-Stage documentation.

3.2. OWNER'S KEY INPUTS

At the start of the FEEP stage, it is recommended that the Owner provide the Project Team(s) with a Project Charter, approved Environmental Management Strategy, and approved FEEP Stage Budget, Deliverables List and Milestone Schedule.

3.3. PROJECT DEFINITION STATEMENT UPDATE SCOPE OF WORK

The scope of work for the Project Definition Statement Update consists of the following.

- A detailed review of hydrology taking into consideration potential climate change impacts.
- A calculation of the options for Power and Energy scenarios, culminating in Hydro's selection of the preferred combination.
- Estimate of the benefits if there is a reduction in spill.
- Gather and review all original design data and construction data, including has built information.
- Determine if existing switchyard equipment can be used or if upgrades are required.
- Development of a project scheme, including the selection of the location of the new powerhouse and type / size of a turbine generator or other major equipment, including review of possible modifications to existing equipment, canals and tunnel system to support a third unit.
- Planning and implementation of a Field Investigation Program.
- Development of an Environmental Management Strategy, including registration of the Project for the Environmental Assessment Process.
- Preparation of a Project Charter, including the selection of the Contracting Strategy.
- Updated Project Scope of Work, Class 5 Cost Estimate and Schedule, include current timelines for supply and delivery of long lead items.

3.4. PROJECT TEAM FEEP-STAGE SCOPE OF WORK

3.4.1. Project Management Discipline

The key Project Management Team deliverable is a *<u>Front-end Execution Plan (FEEP)</u>*, which incorporates the following key documentation.

- Based on the project definition documentation, prepare an updated *<u>Project Scope of Work Document</u> (SOW)* and *<u>Work Breakdown Structure</u> (WBS)*.
- Based on the updated scope of work, prepare a Front-End Execution Plan (FEEP). Key aspect of the FEEP is the contracting strategy which details the project delivery model, compensation model, and sourcing strategy.
- Based on the SOW and WBS, develop the following key sections of the FEEP:
  - Project Management Approach, based on the Project Delivery Model.
  - Project Controls Strategy

  - Health, Safety and Security
  - Quality Management Strategy
- Coordinate the preparation of the following by other disciplines.
  - Environmental Management Plan
  - Engineering Management Plan
  - Procurement Management Strategy
  - Contracting Strategy
  - Construction Management Strategy
  - Construction Sequencing Plan
  - Work Packaging Plan
- Coordinate the preparation of the following Project Controls Documentation.
  - Using the existing schedule data, revised WBS and Work Packaging Plan, develop and optimize a *L3 Project Schedule and Schedule Basis*, incorporating EIA and Long Lead timelines provided by vendors. The *Level 3 (L3) Project Schedule should include*:
    - L4 Project Management Schedule and Schedule Basis
    - L4 Environmental Management Schedule and Schedule Basis
    - L4 Engineering Management Schedule and Schedule Basis
    - L3 Bid Stage Schedule and Schedule Basis
    - L3 Construction Schedule and Schedule Basis with Monte Carlo Simulation which incorporates updated long lead item delivery timelines
  - *Class 3 Cost Estimate, Estimate Basis, and Risk Analysis*, e.g., Monte Carlo Simulation. Update the existing Cost Estimate based on updated WBS / Work Package Plan, the facility optimizations, and revisions to the indirect scope of work, plus updated unit, and material / equipment cost.

3.4.2. Environmental Discipline

The Environmental discipline shall:

- Prepare an Environmental Management Plan.
- Prepare a robust Environmental Registration Document.

3.4.3. Engineering Discipline

The engineering discipline shall:

- Prepare and implement an Engineering Management Plan, including L4 Engineering Schedule and Schedule Basis.

Key Engineering activities to be undertaken are:

- Preparation (review and update) of vendor packages for the Long-Lead Items.

- Based on the project scheme, prepare the preliminary designs develop the information into preliminary engineering work packages, by discipline, including updated MTOs. The EWPs shall support the Work Packaging Plan.
- Update existing scope of work information and prepare a Facility Scope of Work document.
- Assess the impacts of the construction activities on existing operations and work with the Owner's operations team to develop mitigations.

3.4.4. Procurement Discipline

The Procurement discipline shall prepare and implement a *Procurement Management Plan*, Key procurement activities are:

- Working with the Owner to finalize standard contract documentation and procurement processes.
- Working with PM and Construction discipline to document the Contracting Plan.
- Preparation of a L3 Bid Schedule and Schedule basis.
- Issue vendor packages and obtain quotations / delivery timelines for Long Lead Items.

3.4.5. Construction Discipline

The Construction team shall prepare and implement a *Construction Management Plan*. Key aspects of the plan are:

- Define the Path of Construction[2] and optimize the construction sequencing.
- Prepare the L3 Construction Schedule and Basis.
- Prepare a plan for monitoring and control of construction contractor activities.
- Review and update the indirect direct scope of work to reflect current market conditions and the selected project delivery model.
- Work with the Owner to develop mitigations to minimize the impact of construction activities on existing operations.

[2] The Path of Construction is defined as the optimal sequencing of the building of a facility, developed by Construction, Engineering and Project Management Subject Matter Experts (SMEs), typically working backwards from the "end state".

4. PROJECT-SPECIFIC RISKS

4.1. ENVIRONMENTAL RISK

A review of the federal and provincial Environmental Regulatory and Approval context for the proposed NL Hydro Generation Expansion prospects is included in **APPENDIX D**.

4.2. SOCIOECONOMIC INFLUENCES

Socioeconomic influences for the proposed prospects are discussed in **APPENDIX D**. Since this brownfield project is remote, socioeconomic influences will likely be positive.

4.3. MARKET CONDITIONS

The project start date is assumed to be some years away, so it is difficult to comment on market conditions.

4.4. LONG-LEAD ITEMS RISK

The schedule for this prospect outlined in the Main Report assumes a T/G generator is the critical path item for construction and uses today's market conditions timeline for Long-Lead Items.

4.5. TECHNICAL RISK

4.5.1. Hydrotechnical

The hydrology for Cat Arm is out of date and should be updated to a common timeframe with other projects under review so that a valid comparison can be made between the projects. This should then be used to update the Power and Energy study, which will also allow confirmation of the main project characteristics (dam height and type, spillway capacity, installed capacity, etc.).

The report *CAT ARM DEVELOPMENT ADDITION OF UNIT # 3* (Shawmont Report No. SMR-30-85, September 13, 1985) identified that the capacity of the upstream water convenance system was not sized for three (3) units, although the penstock capacity is adequate. That report identified the need for a study to review the adequacy of existing canals and tunnel system to support a third unit. This should be done in conjunction with planned operating methodology to verify that the system will be capable of meeting planned needs.

The potential geometry for the tailrace proposed in the 1985 report should be reviewed with Flow-3D to optimize the geometry and validate the previous assumptions. This should be included in a reassessment of the two (2) options proposed for the location of the new powerhouse.

At the time of the 1985 report, the facility had only been in operation for a short time. New studies should include the latest information on bathymetry to adequately assess the hydraulics. Information should also be provided on the behaviour of the breakwater, which should then be studied to determine if changes are required to accommodate the additional flow.

Since Cat Arm has been in operation since 1985, there should be considerable operational information. This information would be useful for the hydrotechnical studies and should be reviewed as part of the Power and Energy study.

4.5.2. Geotechnical

The 1985 report identified the potential that blasting operations for the excavations for the new tunnel section could cause vibrations that could interrupt power production at the existing plant.

The report also based excavation requirements and quantities on information available from the newly completed facility. Any information from previous investigations should be collected and reviewed to determine the extent of additional field information required to validate the existing information. If the information cannot be found, a more extensive field investigation program may be required.

There could be issues identified in dam safety reviews that need to be taken into consideration for the additional unit. This could include existing tailrace behaviour (riprap protection) and breakwater performance.

4.5.3. Technical Complexity

A cost estimate update in 2010 identified that NL Hydro had purchased a spare runner for the existing turbines that could be used as the runner for the proposed third unit. This assumption should be validated. The Power and Energy study and final design review should consider the optimal selection for the unit to meet current needs and planned operation. There may also be concerns about the preservation of the runner (how long ago was it purchase? Has there been an overhaul since the 2010 report that already put this runner into service?). Use of an existing runner may also limit the suppliers who would be interested in bidding on the work.

The 1985 plan for the third unit considered an expansion to the existing powerhouse and assumed tie-in to existing systems (service water, air, telecommunications, etc.) and that all electrical and mechanical equipment would be identical to that in the existing plant. With changes to technologies since 1985, and possible changes within the plant, this is unlikely to be a valid approach.

The changes required to the switchyard and transmission (that will allow the facility to be expanded with the addition of another 230 kV line) should be reviewed and documented so there is no risk that the requirements could be changed in future.

There is a risk that documentation from the initial installation could be difficult to locate. Hydro should verify what information can be located and that information should be made available for FEEP. This includes as-built drawings, previous topographic and bathymetric information, geotechnical studies and reports, etc.

Any changes made to the facility since initial construction need to be identified and fully documented. There may be changes which impact the assumptions made in previous studies and these changes can affect the current layout or approach.

4.6. PROJECT COST RISK

This project is not technically complex nor difficult to construct. Sound planning and engineering, with a sanction estimate based on bid prices, should address the risks of cost or schedule overruns.

4.7. PROJECT SCHEDULE RISK

See above.

APPENDIX C

PROSPECT 3

ISLAND POND HYDROELECTRIC DEVELOPMENT

PROSPECT OVERVIEW, GAP ANALYSIS & RISKS

TABLE OF CONTENTS

1. PROSPECT 3 OVERVIEW: ISLAND POND HYDROELECTRIC DEVELOPMENT

1.1. LOCATION AND BACKGROUND

Situated in South Central Newfoundland within the existing watershed of the Bay d 'Espoir development, the Island Pond Hydroelectric Development is located on the North Salmon River (see **FIGURE C3.1**). In 1988, ShawMont Newfoundland Limited was commissioned by Hydro to prepare a Final Feasibility Study for the Island Pond Development.[1] The scope of the study included the following.

- Hydrological studies of the watershed
- Geotechnical field investigations
- Topographical surveys of all construction work areas
- Confirmation of selected scheme
- Mitigative measure to eliminate icing in the diversion canal
- Preparation of a detailed schedule and cost estimate

Transmission line considerations and EIA studies were excluded.

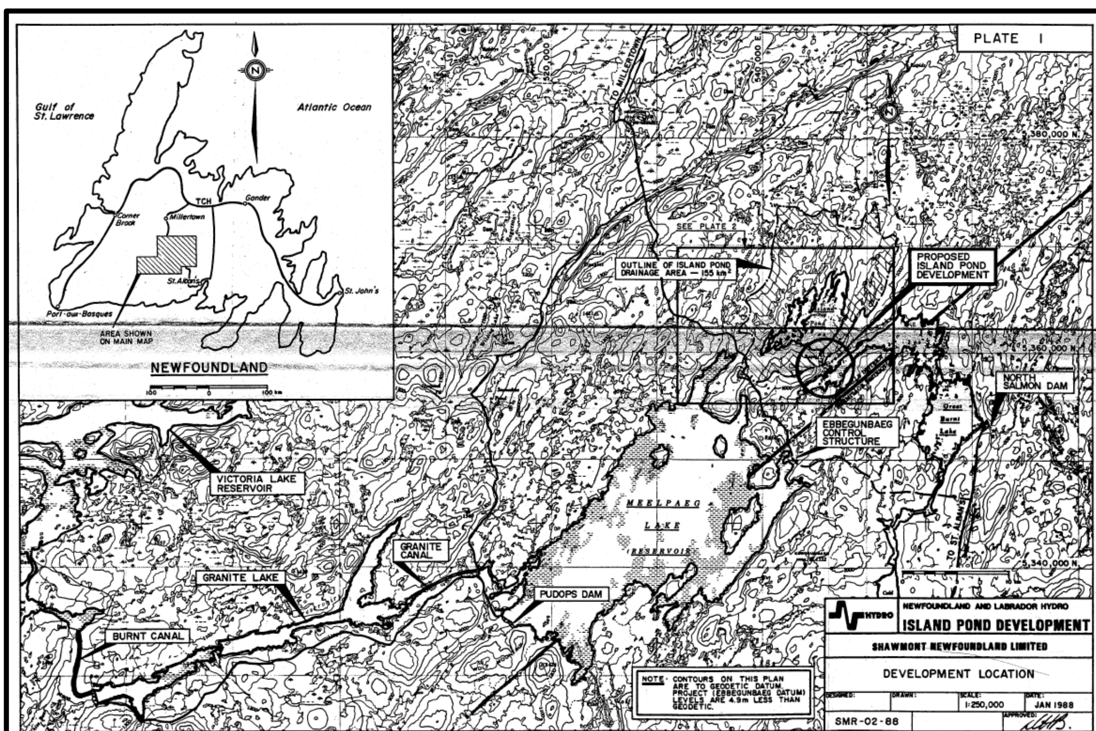

FIGURE C3.1 LOCATION OF ISLAND POND HYDROELECTRIC DEVELOPMENT

[1] *Island Pond Development Final Feasibility Study Volume 1 – Report*. Shawmont Report No. SMR-30-85, January 1988.

In preparation for the construction of the Granite Canal Generation Facility, re-optimization and cost update studies were carried out in 1996-7 for both Granite Canal and Island Pond Generation Facilities.[2] Recommended were two (2)x 18 MW vertical-axis Francis units, although the report acknowledged that Kaplan units would be suitable.

In July 2006, Hydro commissioned SNC-Lavalin ("SLI") to do a further Island Pond study based on the following goals and objectives.[3]

- Optimize the Generation facility, utilizing Kaplan Unit(s).
- Gather field data as required (scope was later reduced due to budget constraints).
- In support of environmental studies, provide:
    - Recommendations related to HADD mitigation measures.
    - Engineering support data.
- Prepare a Capital Cost Estimate and Construction Schedule.

Hydro was to provide the layout of the switchyard and its direct cost of construction while SLI was to determine the site preparation cost. The following section outlines the results of that study.

1.2. PROJECT DESCRIPTION

The proposed generation facility would utilize the available head of approximately 25 m between the Meelpaeg Reservoir and Crooked Lake. The facility would consist of a Roller Compacted Concrete (RCC) dam and a close-coupled powerhouse with one (1) 36 MW Kaplan Turbine, a switchyard, a 0.75 km long Forebay, and a 0.55 km Tailrace. Additional facilities include:

- 3 km long diversion canal between Meelpaeg Reservoir and Island Pond.
- 3.4 km of channel improvements in Meelpaeg Reservoir and Island Pond Reservoir.

Other related Infrastructure included:

- New roadway to connect Ebbegunbaeg and the Upper Salmon / Bay d 'Espoir areas.
- Main Access Road updates including a new bridge at Noel Paul's Brook and access from the existing main road to the project site

1.3. PROPOSED LAYOUT

The layout proposed for the Island Pond development in 2006 is reproduced in **FIGURE C3.2** below. Additional drawings from the 2006 SLI report are reproduced in **FIGURE C3.3**.

Note: it was assumed that, in Year One (1), Hydro would construct a 25 kV distribution line from Ebbegunbaeg control structure to the campsite and powerhouse in order to provide construction power to the site.

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[2] *ISLAND POND / GRANITE CANAL RE-OPTIMIZATION AND COST UPDATE STUDY.* AGRA Shawmont Report SMR-05-96, January 14, 1997.

[3] *Studies for Island Pond Hydroelectric Project FINAL REPORT*. SNC-Lavalin Project No. 722720, December 2006.

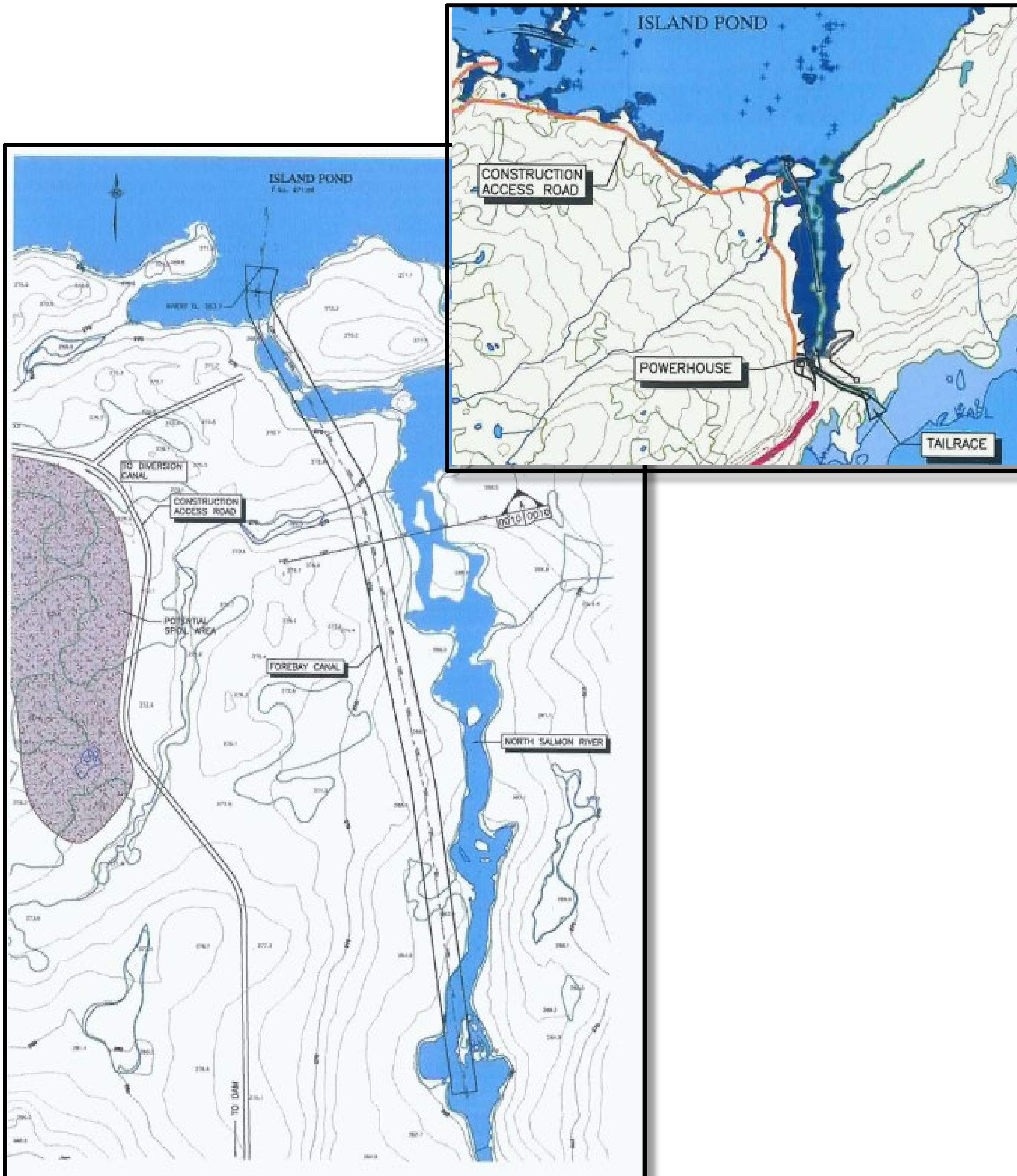

FIGURE C3.2 ISLAND POND HYDROELECTRIC DEVELOPMENT LAYOUT

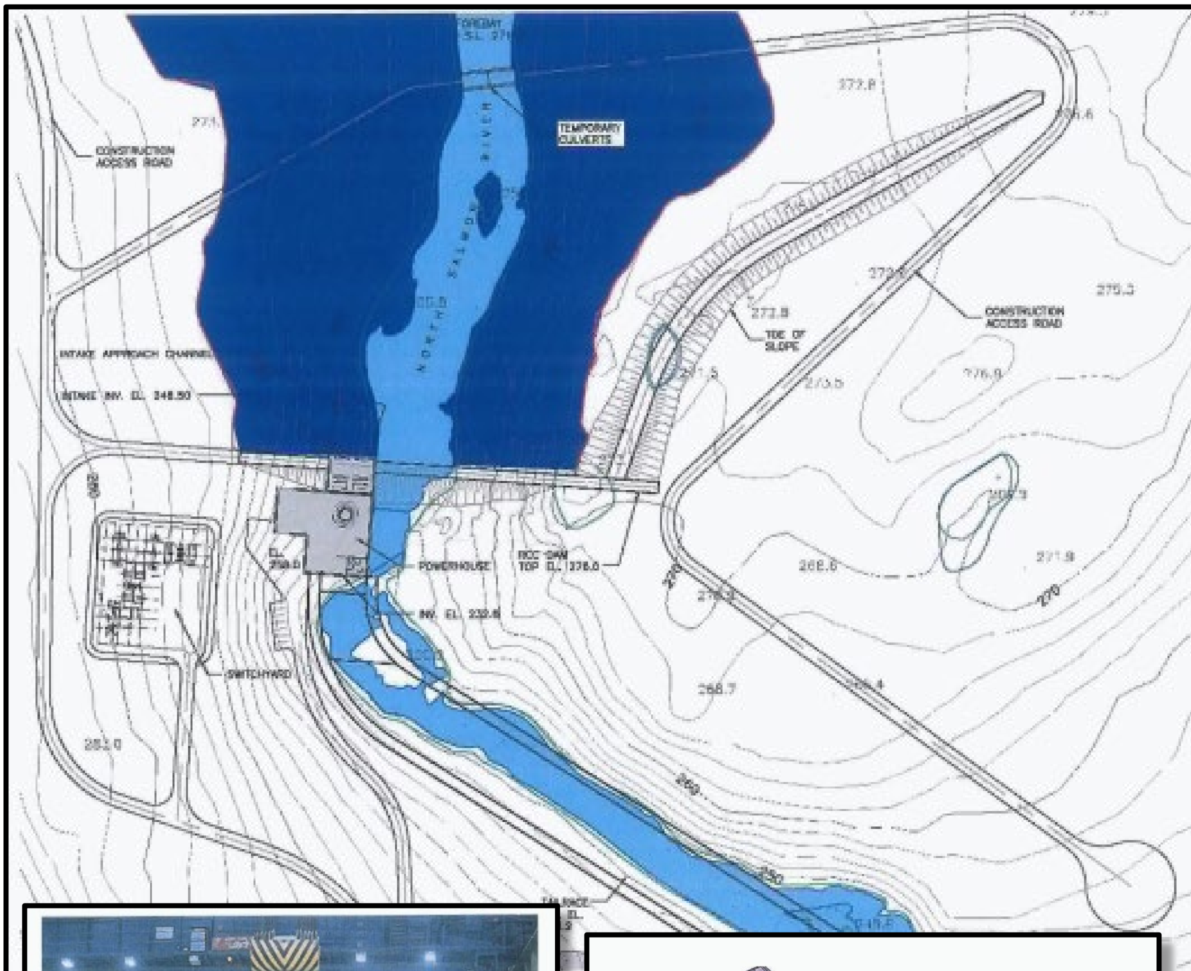

Figure 3-14: Example of a Kaplan Turbine Assembly

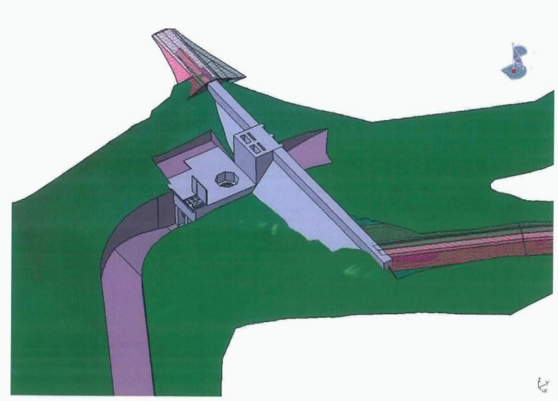

Figure 3-7: 3-D of Power Complex/Dam - Alternative #1

FIGURE C3.3 ISLAND POND DEVELOPMENT DRAWINGS FROM 2006 SLI report

1.4. COST ESTIMATE TO BUILD PROJECT (ESCALATED TO YE-2022)

The 2006 cost estimate was based on a traditional EPCM approach with numerous contract packages, e.g.:

- Construction of temporary and permanent access roads.
- The construction of the powerhouse, dam, intake, tailrace and the HADD in the tailrace.
- The construction of a diversion canal, including the channel improvements in island pond, reservoir clearing and construction of HADD facilities.
- Hydro contracts for transmission lines, distribution lines, switchyard, protection and control, or telecommunications.

The estimate was updated in 2012[4], again in 2018[5], and escalated to YE-2022 as shown in **TABLE C3-1**.

TABLE C3-1: ISLAND POND COST ESTIMATE ESCALATED TO YE-2022

COST ITEM	AMOUNT	NOTES
Material Supply	$5,300,000	From 2012 estimate escalated to 2018 by Hydro.
Labour	$28,266,700	" "
Consultant	$35,333,400	" "
Contract Work	$244,247,900	" "
Other Direct Costs	$1,766,700	" "
Interest	$27,302,400	" "
Contingency	$62,983,154	" "
Total Cost (2018)	$405,200,154	" "
Escalation calculation (2018-2022)	132.5%	2019: 2.2% 2020: 1.2% 2021: 11.4% *Statistics Canada Construction Cost Index (CCPI)*
		2022: 15% *Projection by SLI Cost Estimating Department*
2022 TOTAL ESCALATED COST	**$536,890,204**	
AACE Estimate Accuracy (Index of 1 = +10% / -5%)	+50% / -25%	Class 5 accuracy index range = 4 to 20 Index for this estimate assumed = 5

[4] *Portland Creek and Island Pond Hydroelectric Projects Update Cost Estimates*. SNC-Lavalin 501325-40ER-0001-PA, May 2012.

[5] *Island Pond Hydroelectric Development*. NL Hydro, August 29, 2018.

1.5. KEY TECHNICAL METRICS

The following key technical metrics were developed from the above information and used in the Screening and Ranking Process.

- Power (MW Installed): One (1) x 36 MW Kaplan Turbine Generator
- Cost per MW of Power (escalated to YE-2022): $14.9 million / MW
- Overall Project Duration : 6 Years
  - Planning Timeline: 3 Years
  - Execution (Construction) Timeline: 3 Years
  - Less Overlap Planning/Execution: 0 Years
  - Overall Development Timeline: 6 Years

2. EXISTING PROJECT INFORMATION DATA GAP

2.1. OVERVIEW

The 2006 report was considered at the feasibility level at the time of preparation. In terms of the standard recommended in the Main Report of this study, the 2006 report is lacking in execution planning and some elements of construction planning, an Environmental Management plan is required, as well as updated Hydrology / Power and Energy Calculations. Further field investigation work is also required

2.2. DATA GAP

To advance this prospect to a Front-End Execution Planning (FEEP) standard, the following gaps remain (see **TABLE C3-2**).

TABLE C3-2: GAP ANALYSIS FOR PROSPECT 3: ISLAND POND

STAGE 1: PROJECT DEFINITION		
RESPONSIBLE GROUP	**DELIVERABLE**	**REQUIREMENTS TO ADDRESS GAP**
Owner / Corporate	**PROJECT DEFINITION STATEMENT**	Update Hydrology, then Update Power / Energy Calculations
	PROJECT CHARTER	Develop Project Charter as per standard for internal approval and sign-off, including recommended Contracting Strategy. Develop the Environmental Management Strategy. Approve FEEP Stage Budget, Deliverables List, and Milestone Schedule.
STAGE 2: FEEP		
RESPONSIBLE GROUP	**DELIVERABLE**	**REQUIREMENTS TO ADDRESS GAP**
Project Management	**PROJECT EXECUTION PLAN (PEP)**	
	Scope of Work	Update Scope Work document based on completed field data and update preliminary design / MTOs
	Project Management Strategy	Key elements of the execution strategy will need to be reviewed and updated based on the selected Project Delivery Model.
	Project Controls Strategy	Determine how cost estimating and schedule development activities are going to be coordinated.
	Health & Safety Strategy	Prepare HS&S Project Strategy.
	QA / QC Strategy	Prepare Quality Management Strategy.
	PROJECT CONTROLS DOCUMENTATION	
	Cost Estimate (Class 4 / Class 3)	Update based on updated contracting strategy, schedule, design optimizations, updated unit costs and costs for Long-Lead items and the cost of implementing the Environmental Protection Plan.
	Schedule	Prepare L2 based on updated MTOs, Timelines for long-lead items, Environmental timelines, Construction Sequencing, and Contracting Strategy.
Environmental Management	**ENVIRONMENTAL MANAGEMENT PLAN**	Based on the Environmental Management Strategy, develop a detailed Management Plan.
	PROJECT REGISTRATION / EIS	Prepare Robust Environmental Registration Document.
	FACILITY SCOPE OF WORK	Based on the Design Optimizations, and revised MTO's, update the Scope of Work for each Facility.

Engineering	**PRELIMINARY ENGINEERING**	Review the 2006 preliminary designs and finalize the scope of work for the field program.
	FIELD INVESTIGATIONS SOW	Define a detailed Field Investigation Plan.
	DESIGN OPTIMIZATIONS	Optimize the 2006 preliminary designs based on results of the field program.
	UPDATED PRELIMINARY ENGINEERING	Complete preliminary design based on the optimizations.
	MTOs	Update the Facility MTO's and the quantities in the cost estimate and schedule duration calculations, based on the update Preliminary Engineering.
Supply Chain Management	**CONTRACTING STRATEGY**	Based on Hydro's selected Contracting Strategy, prepare a Project Contracting Strategy document, identify standard contract documentation and procurement processes.
	BID & EVALUATION PLAN	Prepare a plan which documents standard contract documentation, the bid management process, including bid evaluation plans, approval authorities, etc..
	LONG-LEAD ITEMS VENDOR PACKAGES	Issue vendor packages and obtain quotations / delivery timelines for Long Lead Items.
	FIELD INVESTIGATIONS PLAN	Issue PO for Field Investigation Activities.
Construction	**CM STRATEGY**	Prepare and implement a Field Investigation Program Execution Plan based on the scope of work prepared by engineering. Prepare Construction Management Plan based on the Contracting Strategy
	PATH OF CONSTRUCTION	Undertake Construction Planning activities necessary to develop the Path of Construction (sequencing).
	CONSTRUCTION SCHEDULE	Based on the Path of Construction, update construction schedule.

3. SCOPE OF WORK TO COMPLETE FEEP STAGE

3.1. PURPOSE

This section outlines the scope of work ("SOW") necessary to advance the 2006 SLI Feasibility Study to meet industry-standard FEEP-level documentation requirements for this prospect, including updates to cost and schedule.

3.2. OWNER'S KEY INPUTS

At the start of the FEEP stage, it is recommended that the Owner provide the Project Team(s) with a Project Charter, approved Environmental Management Strategy, and approved FEEP Stage Budget, Deliverables List and Milestone Schedule.

3.3. PROJECT DEFINITION STATEMENT UPDATE SCOPE OF WORK

The scope of work for the Project Definition stage consists of the following.

- A detailed review of hydrology taking into consideration potential climate change impacts.
- A calculation of the options for Power and Energy scenarios, culminating in Hydro's selection of the preferred combination.

3.4. PROJECT TEAM FEEP-STAGE SCOPE OF WORK

3.4.1. Project Management Discipline

The key Project Management Team deliverable is a *Front-end Execution Plan (FEEP)*, which incorporates the following key documentation.

- Based on the scope of work outlined in existing documentation, and the design optimizations to be prepared (see **3.3.3. Engineering** below), prepare an updated *Project Scope of Work Document (SOW)* and *Work Breakdown Structure (WBS)*.
- Based on the updated SOW, prepare a Front-End Execution Plan (FEEP). A key part of the plan is the Contracting Strategy, which includes a Project Delivery Model, Compensation Model, and Sourcing Strategy.
- Based on the SOW and WBS, develop the following key sections of the FEEP:
  - Project Management Approach
  - Project Controls Strategy
  - Health, Safety and Security
  - Quality Management Strategy
- Coordinate the preparation of the following by other disciplines.
  - Environmental Management Plan
  - Engineering Management Plan
  - Procurement Management Strategy
  - Contracting Strategy
  - Construction Management Strategy
  - Construction Sequencing Plan

- Work Packaging Plan

- Coordinate the preparation of the following Project Controls Documentation.
    - Using the existing schedule data, revised WBS and Work Packaging Plan, develop and optimize a *L3 Project Schedule and Schedule Basis*, incorporating EIA and Long Lead timelines provided by vendors. The *Level 3 (L3) Project Schedule should include*:
        - L4 Project Management Schedule and Schedule Basis.
        - L4 Environmental Management Schedule and Schedule Basis.
        - L4 Engineering Management Schedule and Schedule Basis.
        - L3 Bid Stage Schedule and Schedule Basis.
        - L3 Construction Schedule and Schedule Basis with Monte Carlo Simulation which incorporates updated long lead item delivery timelines.
    - *Class 3 Cost Estimate, Estimate Basis, and Risk Analysis*, e.g., Monte Carlo Simulation. Update the existing Cost Estimate based on updated WBS / Work Package Plan, the facility optimizations, and revisions to the indirect scope of work, plus updated unit, and material / equipment cost.

Note: At the present stage of planning, the following key timelines and impacts remain unknown:

- Environmental Approval Process and relates impacts on cost and schedule.
- Owner's Planning and Approval Process.
- Detailed Engineering Resource availability.
- Major Equipment availability and cost.

3.4.2. Environmental Discipline

The Environmental discipline shall:

- Prepare an Environmental Management Plan.
- Prepare a robust Environmental Registration Document.

3.4.3. Engineering Discipline

The Engineering discipline shall:

- Prepare a *Scope of Work for Field Investigation Program* for immediate execution by Construction, including the preparation and submission of applications for permits to carry out the field work.
- Prepare and implement an Engineering Management Plan, including L4 Engineering Schedule and Schedule Basis.
- Key Engineering activities to be undertaken are:
    - Interpretation and reporting of the field investigation results.
    - Update vendor packages for the Long-Lead Items.
    - Based on the updated Project Definition Statement and data gathered during the winter and summer field programs, undertake design optimizations / preliminary reviews as recommended in the SLI 2006 report, which include:
        - Update the forebay and tailrace preliminary design and MTO, based on the bedrock profile.

  - Review the Dam, Powerhouse and Dyke preliminary designs based on the geotechnical data.
  - Preliminary Design of the 3.4 km of Channel Improvements in Meelpaeg Reservoir and Island Pond Reservoir based on the bathymetric and geotechnical data including detailed quantity calculations for an MTO.
  - Preliminary Designs the HADD Facilities and prepare an MTO.
  - Quantify Aggregate sources, including HADD grave, and prepare quantities for Pit development.
  - Identify areas of Acid Generating Rock (AGR) and develop the necessary mitigation measures.
- Update existing scope of work information and prepare a Facility Scope of Work document.
- Update existing preliminary designs and develop into preliminary engineering work packages, by discipline, including updated MTOs. The EWPs shall support the Work Packaging Plan.
- Assess the impacts of the construction activities on operations and work with the Owner's operations team to develop mitigations.

3.4.4. Procurement Discipline

The Procurement discipline shall prepare and implement a *Procurement Management Plan*, Key procurement activities are:

- Working with the Owner to finalize standard contract documentation and procurement processes.
- Working with PM and Construction discipline to develop a Contracting Plan.
- Preparation of a L3 Bid Schedule and Schedule basis.
- Issue vendor packages and obtain quotations / delivery timelines for Long Lead Items.
- Prepare and issue POs for Field Program.

3.4.5. Construction Discipline

In the Project Definition Statement update, the construction discipline shall prepare and implement a Field Investigation Program Execution Plan, based on the scope of work provided by Engineering. The plan shall include:

- L4 Field Investigation Schedule and Basis
- Class 2 Field Investigation Cost Estimate and Basis
- Upon approval, execute the field investigation program, with functional management from engineering.

The Construction team shall prepare and implement a *Construction Management Plan*. Key aspects of the plan are:

- Define the Path of Construction[6] and optimize the construction sequencing.

[6] The Path of Construction is defined as the optimal sequencing of the building of a facility, developed by Construction, Engineering and Project Management Subject Matter Experts (SMEs), typically working backwards from the "end state".

- Prepare the L3 Construction Schedule and Basis.
- Prepare a plan for monitoring and control of construction contractor activities.
- Review and update the indirect direct scope of work to reflect current market conditions and the selected project delivery model.
- Work with the Owner to develop mitigations to minimize the impact of construction activities on existing operations.

4. PROJECT-SPECIFIC RISKS

The 2006 SLI report "Studies for Island Pond Hydroelectrical Project" has a detailed review of technical risk for the project. This section identifies similar risks and concerns.

4.1. ENVIRONMENTAL RISK

A review of the federal and provincial Environmental Regulatory and Approval context for the proposed NL Hydro Generation Expansion prospects is included in **APPENDIX D**.

The 2006 report indicates that the key environmental concern is the disruption to fish habitat. Fish habitat studies were undertaken in 2006, but extensive discussion between all parties is required before the level of effort to complete this assessment can be determined.

A high-level assessment of the environmental management strategy undertaken as a part of this study suggests that up to three (3) years will be required to obtain environmental approval, placing this process on the schedule critical path.

Regarding reservoir clearing, there may be technical limitations on being able to clear the full area required. More recent imagery may help refine area to be cleared and help understand the accessibility of those areas.

The 2006 SLI report identifies the need for a more rigid evaluation of potential spoil areas to understand potential impacts. There are five (5) spoil areas currently identified for potential use.

4.2. SOCIOECONOMIC INFLUENCES

Socioeconomic influences for the proposed prospects are also discussed in **APPENDIX D**.

4.3. MARKET CONDITIONS

As the project is relatively small by hydro standards, Contractor Capability / Availability should not be an issue (there are several local contractors who could undertake this work).

4.4. LONG-LEAD ITEMS RISK

Due to the small size of the Turbine / Generator, Supply Chain issues should be manageable and are unlikely to seriously impact the schedule. However, the design, manufacturing, and installation timeline being quoted in 2022 by North American suppliers for the Turbine / Generator is 30 months for this type of T / G. In the 2006 SLI report, this lead time was only 18 months and was still considered a schedule risk.

4.5. TECHNICAL RISK

4.5.1. Hydrotechnical

The hydrology for Island Pond is out of date. The hydrology should be updated to a common time base with other projects under review so that a valid comparison can be made between projects. This should be used to update the power and energy study, which will also allow confirmation of the main project characteristics (dam height and type, spillway capacity, installed capacity, etc.).

The review of hydrology should consider the potential impact of climate change over the life of the project, and this should be taken into consideration in finalizing designs.

Previous studies identified the need to improve flow characteristics (channel improvements) in the reservoirs and approach channels. The diversion canal was optimized in a study in 1988 but has not been updated since. Updated bathymetry will be required to set up flow models to revisit the previous design and determine if the improvements are possible. This should also consider the risk of ice effects and methods to mitigate this risk.

4.5.2. Geotechnical

A geotechnical Field Investigation Program was identified in the 2006 SLI report to address the risk of unknown geotechnical conditions for the facilities. This program should be reviewed prior to implementation to ensure it addresses all concerns.

The issue of potential for the rock to be acid-generating needs to be addressed (the extent of the problem and a plan to address). This can be a complex issue to deal with, as described in the 2006 SLI study.

The field investigations carried out in 2006 stated that excavated rock from the forebay canal and intake/powerhouse and other excavations would not be suitable for concrete. Suitable sources of concrete aggregate were identified but it should be verified that they are close, assessable and have sufficient quantities of material available. Similarly, sources for other construction materials should be confirmed.

During the 2006 field work, rock samples were identified as having acid generating properties. This can be quantified during the next field program and mitigation measures can be incorporated into the earthwork's specifications. A $1.0 million allowance was added to the 2006 cost estimate.

4.5.3. Technical Complexity

A Roller Compacted Concrete (RCC) dam was suggested for consideration in the previous study. This should be assessed in light of recent Muskrat Falls experience. The commentary on RCC vs. Conventional Mass Concrete (CVC) should be updated to consider recent advancements in RCC construction. Alternative dam types should be considered to ensure most cost-effective solution.

The Turbine SME concurs that the 36 MW turbine would not require a model test to optimize efficiency.

Transmission line requirements are different from the 2006 SLI report assumptions (see the 2018 Transmission System Review document. These should be reviewed to verify technical requirements and costs.

Ground resistivity measurements must be performed to allow design of the earthing grid. This should be performed in conjunction with the Field Investigation Program in order to finalize the design.

The dewatering scheme for the diversion canal construction should be revisited to understand risks related to cofferdam sizing and location and to finalize optimum routing and configuration. The Forebay Canal should also be reviewed. These reviews should consider environmental concerns, as identified in previous reports.

The powerhouse cofferdam is the only critical dewatering facility that may be at risk of an unforeseen flood event. Construction during the summer is the least cost mitigation.

4.6. PROJECT COST RISK

The 2006 SLI report reviewed aspects of "commercial risk" that included significant wage increase trends in the labour market. At this time, the largest risk factors to cost (and, in some respects, to schedule) will be volatility in fuel costs, contractor capacity (availability of human resources, both technical and construction), and the potential for excessive cost escalation due to local market conditions and global factors.

4.7. PROJECT SCHEDULE RISK

The 2006 SLI report identified "scheduling considerations" as a key risk, with specific factors including the need to expedite the Environmental Approval Process and Project Registration, pre-ordering of construction camp units, and T / G delivery time slippage (see **SECTION 4.4** above).

APPENDIX C

PROSPECT 4

ROUND POND HYDROELECTRIC DEVELOPMENT

PROSPECT OVERVIEW, GAP ANALYSIS & RISKS

TABLE OF CONTENTS

1. PROSPECT 4 OVERVIEW: ROUND POND HYDROELECTRIC DEVELOPMENT

1.1. LOCATION AND BACKGROUND

In 1988, Shawinigan Newfoundland Limited carried out a final feasibility study of the Round Pond Development (see **FIGURE C4.1**) with the key objective of establishing an accurate cost estimate. Shawinigan's scope of work included the following.

- Hydrological Studies
- Site Surveys and Geotechnical investigations
- Conceptual layouts
- Preliminary designs and optimizations
- Cost Estimate and Schedule Timelines

Concurrent with Shawinigan's work, Hydro carried out a review of terminals, transmission, telecontrol and equipment requirements.[1] In 2012, Hatch was retained to update the cost estimate and schedule from 1988.[2]

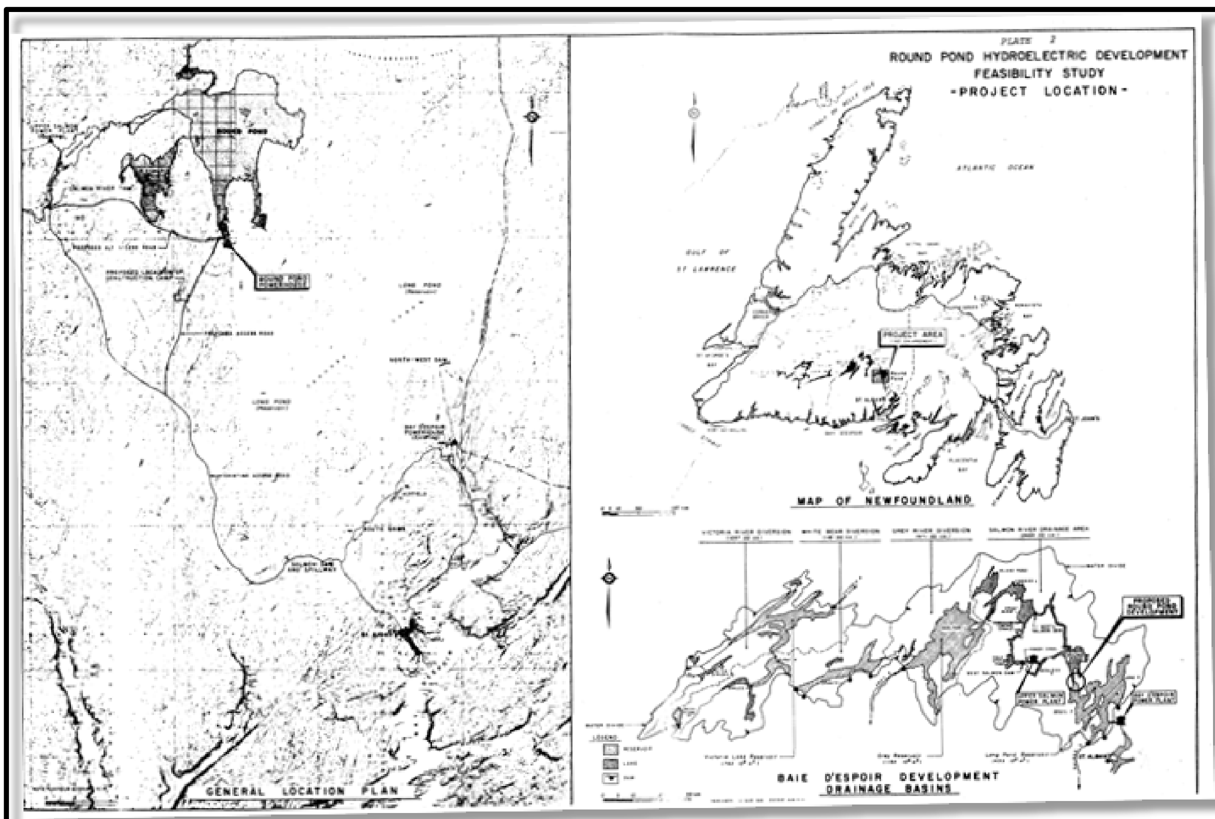

FIGURE C4.1 PROJECT LOCATION – ROUND POND

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[1] *Feasibility Study – Round Pond Development Summary Report*. NL Hydro Engineering Dept., February 1989.

[2] *Round Pond Hydroelectric Development – Update of the 1988 Cost Estimate*. Hatch Report H341357-0000-00-218-0001, May 7, 2012.

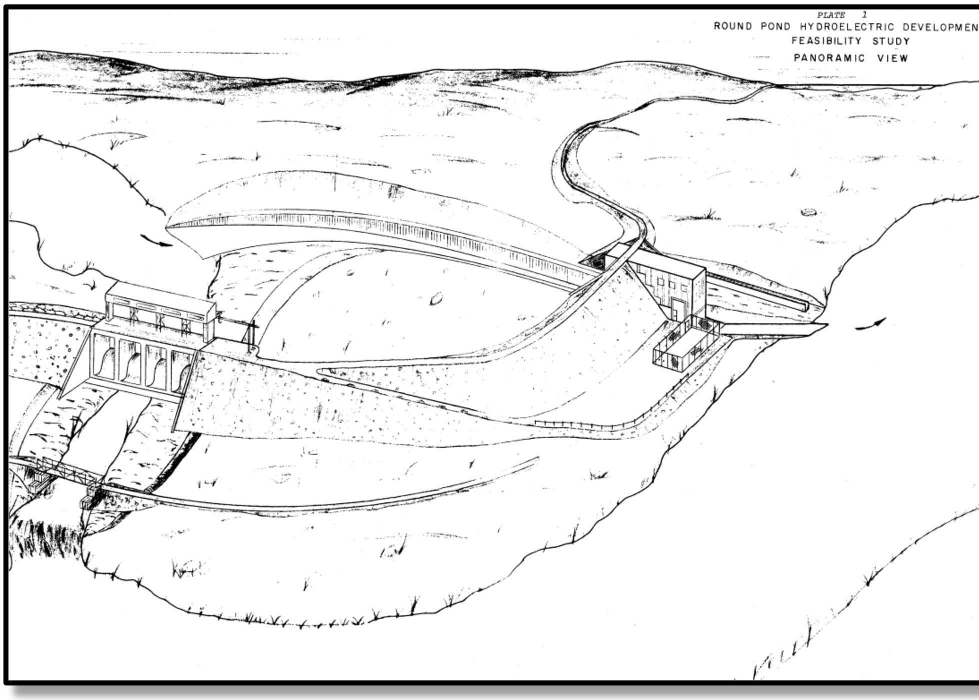
1.2. PROJECT DESCRIPTION

The proposed generation facility would utilize the available head of approximately 12 m between the Godaleich Pond and Long Pond Reservoir. The development would consist of the following.

- Generation Facilities
  - Close-Coupled Powerhouse / Intake – 18 MW Bulb (Pit) Turbine Generator
  - Power Canal
  - Tailrace
- Reservoir
  - Main Dam
  - Gated Spillway
  - Saddle Dams 1, 2 & 3
- Access
  - Main Access Road
  - Access to Saddle Dam 3
- Temporary Facilities
  - Access / Bridges
  - Cofferdams
  - Laydowns
  - Camp Site
  - Camp Facilities
  - Construction Power
  - Fuel Storage
- Transmission
  - 66 kV Switchyard
  - 44 km of 69 kV Transmission Line
  - Telecontrol
- Environmental Infrastructure
  - Fish Passageway

1.3. PROPOSED LAYOUT

The layout proposed for the Round Pond development is reproduced in **FIGURE C.3.2** below.



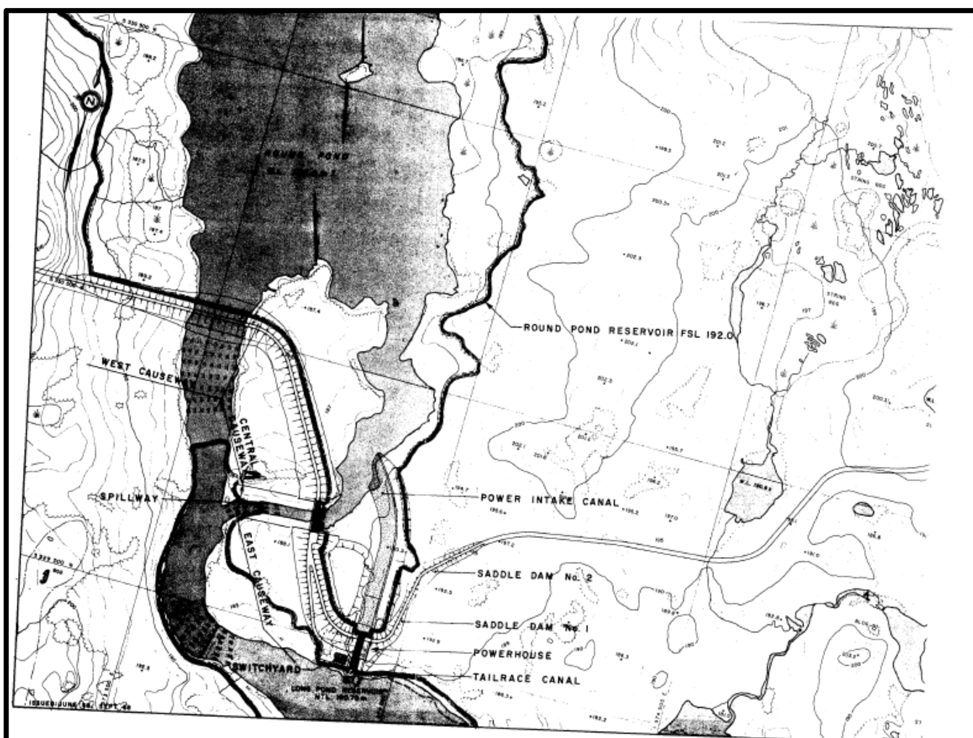


FIGURE C4.2: ROUND POND PROPOSED LAYOUT

1.4. COST ESTIMATE TO BUILD PROJECT (ESCALATED TO YE-2022)

The 2012 cost update by Hatch was further updated in 2018 by Hydro and escalated to YE-2022 as shown in **TABLE C4-1**. (Note that Environmental Mitigation costs were not addressed in the reports.)

TABLE C4-1: ROUND POND COST ESTIMATE ESCALATED TO YE-2022

COST ITEM	AMOUNT	NOTES
Material Supply	$3,115,000	From Hydro's 2018 update of Hatch 2012 update
Labour	$16,613,200	" "
Consultant	$20,766,500	" "
Contract Work	$145,215,800	" "
Other Direct Costs	$1,038,300	" "
Interest	$23,842,400	" "
Contingency	$37,349,700	" "
Total Cost (2018)	$247,940,800	" "
Escalation calculation (2018-2022)	132.5%	2019: 2.2% 2020: 1.2% 2021: 11.4% *Statistics Canada Construction Cost Index (CCPI)* 2022: 15% *Projection by SLI Cost Estimating Department*
2022 TOTAL ESCALATED COST	**$328,541,560**	
AACE Estimate Accuracy (Index of 1 = +10% / -5%)	+50% / -25%	Class 4 accuracy index range = 3 to 12 Index for this estimate assumed = 5

1.5. KEY TECHNICAL METRICS

The following key technical metrics were used in the Screening and Ranking Process.

- Power (MW Installed): One (1) Bulb (Pit) Turbine Generators with Installed Capacity 18 MW
- Cost per MW of Power (escalated to YE-2022): $18.3 million / MW
- Overall Project Duration : 5.6 Years
  - Planning Timeline: 3.0 Years
  - Execution (Construction) Timeline: 3.3 Years
  - Less Overlap Planning/Execution: -0.7 Year
  - Overall Development Timeline: 5.6 Years

2. EXISTING PROJECT INFORMATION DATA GAP

2.1. OVERVIEW

While the 1989 study was considered a Feasibility Study, it is suggested the existing project documentation be considered Project Definition level, given it is thirty-seven (37) years old.

2.2. DATA GAP

A complete review and update of the project definition, followed by a FEEP study is recommended. The updated project definition should be based on updated Hydrological data and recalculated power and energy availability, including selection of the Turbine Generator unit and related equipment. Included in this stage should be the project registration for the environmental assessment process and a preliminary field investigation program.

The 1989 study, Section 7, indicates that the project was registered with the department of environment in 1987 and environmental concerns were fish habitat, waterfowl breeding habitat, caribou, raptors and moose and the minster required that an EIS be prepared. The environmental registration information is missing from the project data provided for this study.

To advance this work to a *Front-End Execution Planning (FEEP) standard*, the following gaps remain (see **TABLE C4-2**).

TABLE C4-2: GAP ANALYSIS FOR PROSPECT 3: ROUND POND

STAGE 1: PROJECT DEFINITION		
RESPONSIBLE GROUP	**DELIVERABLE**	**REQUIREMENTS TO ADDRESS GAP**
Owner / Corporate	**PROJECT DEFINITION STATEMENT**	Undertake the Hydrotechnical Review. Plan and Execute the Field Investigation Program, including environmental field work. Optimize the Scheme and Prepare a new Class 5 Cost estimate and L2 Schedule.
	PROJECT CHARTER	Prepare a Project Charter including selection of a Contracting Strategy. Develop the Environmental Management Strategy. Approve FEEP Stage Budget, Deliverables List and Milestone Schedule.
STAGE 2: FEEP		
RESPONSIBLE GROUP	**DELIVERABLE**	**REQUIREMENTS TO ADDRESS GAP**
Project Management	**PROJECT EXECUTION PLAN (PEP)**	
	Scope of Work	Update Scope Work document based on completed field data and update preliminary design / MTOs.
	Project Management Strategy	Key elements of the execution strategy will need to be reviewed and updated based on the selected Project Delivery Model.
	Project Controls Strategy	Determine how cost estimating and schedule development activities are going to be coordinated.
	Health & Safety Strategy	Prepare HS&S Project Strategy.
	QA / QC Strategy	Prepare Quality Management Strategy.
	PROJECT CONTROLS DOCUMENTATION	
	Cost Estimate (Class 4 / Class 3)	Update based on updated contracting strategy, schedule, design optimizations, updated unit costs and costs for Long-Lead items and the cost of implementing the Environmental Protection Plan.
	Schedule	Prepare L2 based on updated MTOs, Timelines for long-lead items, Environmental timelines, Construction Sequencing, and Contracting Strategy.
Environmental Management	**ENVIRONMENTAL MANAGEMENT PLAN**	Based on the Environmental Management Strategy, develop a detailed Management Plan.
	PROJECT REGISTRATION / EIS	Prepare a robust Project Registration Document.

Engineering	**FACILITY SCOPE OF WORK**	Prepare a Facility Scope of Work.
	PRELIMINARY ENGINEERING	Prepare and optimize Preliminary Designs.
	FIELD INVESTIGATIONS SOW	Included in Project Definition Update.
	DESIGN OPTIMIZATIONS	Included in Preliminary Engineering above.
	UPDATED PRELIMINARY ENGINEERING	Included in Preliminary Engineering above.
	MTOs	Prepare MTOs.
Supply Chain Management	**CONTRACTING STRATEGY**	Work with PM and Construction discipline to document the Contracting Plan.
	BID & EVALUATION PLAN	Prepare Plan and work with the Owner to finalize standard contract documentation and procurement processes. Prepare Bid Plan.
	LONG-LEAD ITEMS VENDOR PACKAGES	Issue Vendor Packages and obtain quotations / delivery times for Long-Lead Items.
Construction	**FIELD INVESTIGATIONS PLAN**	Included in Project Definition Update.
	CM STRATEGY	Based on the Project Delivery Method, and Project Execution Plan, prepare a Construction Management Strategy.
	PATH OF CONSTRUCTION	Define the Path of Construction and optimize the construction sequencing.
	CONSTRUCTION SCHEDULE	Prepare a L3 construction Schedule and Basis.

TABLE C4-2: GAP ANALYSIS FOR PROSPECT 3: ROUND POND

STAGE 1: PROJECT DEFINITION		
RESPONSIBLE GROUP	**DELIVERABLE**	**REQUIREMENTS TO ADDRESS GAP**
Owner / Corporate	**PROJECT DEFINITION STATEMENT**	Undertake the Hydrotechnical Review. Plan and Execute the Field Investigation Program, including environmental field work. Optimize the Scheme and Prepare a new Class 5 Cost estimate and L2 Schedule.
	PROJECT CHARTER	Prepare a Project Charter including selection of a Contracting Strategy. Develop the Environmental Management Strategy. Approve FEEP Stage Budget, Deliverables List and Milestone Schedule.
STAGE 2: FEEP		
RESPONSIBLE GROUP	**DELIVERABLE**	**REQUIREMENTS TO ADDRESS GAP**
Project Management	**PROJECT EXECUTION PLAN (PEP)**	
	Scope of Work	Update Scope Work document based on completed field data and update preliminary design / MTOs.
	Project Management Strategy	Key elements of the execution strategy will need to be reviewed and updated based on the selected Project Delivery Model.
	Project Controls Strategy	Determine how cost estimating and schedule development activities are going to be coordinated.
	Health & Safety Strategy	Prepare HS&S Project Strategy.
	QA / QC Strategy	Prepare Quality Management Strategy.
	PROJECT CONTROLS DOCUMENTATION	
	Cost Estimate (Class 4 / Class 3)	Update based on updated contracting strategy, schedule, design optimizations, updated unit costs and costs for Long-Lead items and the cost of implementing the Environmental Protection Plan.
	Schedule	Prepare L2 based on updated MTOs, Timelines for long-lead items, Environmental timelines, Construction Sequencing, and Contracting Strategy.
Environmental Management	**ENVIRONMENTAL MANAGEMENT PLAN**	Based on the Environmental Management Strategy, develop a detailed Management Plan.
	PROJECT REGISTRATION / EIS	Prepare a robust Project Registration Document.

Engineering	**FACILITY SCOPE OF WORK**	Prepare a Facility Scope of Work.
	PRELIMINARY ENGINEERING	Prepare and optimize Preliminary Designs.
	FIELD INVESTIGATIONS SOW	Included in Project Definition Update.
	DESIGN OPTIMIZATIONS	Included in Preliminary Engineering above.
	UPDATED PRELIMINARY ENGINEERING	Included in Preliminary Engineering above.
	MTOs	Prepare MTOs.
Supply Chain Management	**CONTRACTING STRATEGY**	Work with PM and Construction discipline to document the Contracting Plan.
	BID & EVALUATION PLAN	Prepare Plan and work with the Owner to finalize standard contract documentation and procurement processes. Prepare Bid Plan.
	LONG-LEAD ITEMS VENDOR PACKAGES	Issue Vendor Packages and obtain quotations / delivery times for Long-Lead Items.
Construction	**FIELD INVESTIGATIONS PLAN**	Included in Project Definition Update.
	CM STRATEGY	Based on the Project Delivery Method, and Project Execution Plan, prepare a Construction Management Strategy.
	PATH OF CONSTRUCTION	Define the Path of Construction and optimize the construction sequencing.
	CONSTRUCTION SCHEDULE	Prepare a L3 construction Schedule and Basis.

3. SCOPE OF WORK TO COMPLETE FEEP STAGE

3.1. PURPOSE

This section outlines the scope of work necessary to update Project Definition Stage and then prepare the FEEP-stage scope of work. This assumes that the Hydrotechnical review will redefine the Power and Energy configuration and, therefore, reopen a Project Scheme review. A Field Investigation is proposed to be undertaken during Project Definition such that the FEEP stage can be executed in an uninterrupted workflow.

3.2. OWNER'S KEY INPUTS

The key input required here is Hydro's internal assessment of its projected power and energy needs, followed by the preparation of a Project Charter, approved Environmental Management Strategy, and approved FEEP Stage Budget, Deliverables List, and Milestone Schedule.

3.3. PROJECT DEFINITION STATEMENT UPDATE SCOPE OF WORK

The scope of work consists of the following.

- Development of an Environmental Management Strategy. Note: Section 7 of the 1989 Feasibility Study indicates that the project was registered in 1987 resulting in the need for an Environmental Impact Statement. Like Island Pond, Fish Habit is the key environmental concern. Other noted concerns were waterfowl breeding habitat, caribou, raptors, and moose.
- A detailed review of hydrology taking into consideration potential climate change impacts.
- A calculation of the options for Power and Energy scenarios, cumulating in Hydro's selection of the preferred combination.
- Review and Optimization of the project scheme.
- Planning and execution of Field Investigation Program, including key field work to support component studies which are likely to be required to address potential environmental concerns.
- Prepare new Class 5 Cost Estimate and L2 Schedule based on the optimized scheme.
- Preparation of a Project Charter, including the selection of a Contracting Strategy.
- Approved FEEP Stage Scope of Work and Cost Estimate and Schedule.

3.4. PROJECT TEAM FEEP-STAGE SCOPE OF WORK

3.4.1. Project Management Discipline

The key Project Management Team deliverable is a *Front-end Execution Plan (FEEP)*, which incorporates the following key documentation.

- Based on the project definition documentation, prepare an updated *Project Scope of Work Document (SOW)* and *Work Breakdown Structure (WBS)*.
- Based on the updated scope of work, prepare a Front-End Execution Plan (FEEP). Key aspect of the FEEP is the contracting strategy which details the project delivery model, compensation model, and sourcing strategy.
- Based on the SOW and WBS, develop the following key sections of the FEEP:
  - Project Management Approach, based on the project delivery model.
  - Project Controls Strategy

- Health, Safety and Security
- Quality Management Strategy

- Coordinate the preparation of the following by other disciplines.
  - Environmental Management Plan
  - Engineering Management Plan
  - Procurement Management Strategy
  - Contracting Strategy
  - Construction Management Strategy
  - Construction Sequencing Plan
  - Work Packaging Plan
- Coordinate the preparation of the following Project Controls Documentation.
  - Using the existing schedule data, revised WBS and Work Packaging Plan, develop and optimize a *L3 Project Schedule and Schedule Basis*, incorporating EIA and Long Lead timelines provided by vendors. The *Level 3 (L3) Project Schedule should include*:
    - L4 Project Management Schedule and Schedule Basis
    - L4 Environmental Management Schedule and Schedule Basis
    - L4 Engineering Management Schedule and Schedule Basis
    - L3 Bid Stage Schedule and Schedule Basis
    - L3 Construction Schedule and Schedule Basis with Monte Carlo Simulation which incorporates updated long lead item delivery timelines
  - *Class 3 Cost Estimate, Estimate Basis, and Risk Analysis*, e.g., Monte Carlo Simulation. Update the existing Cost Estimate based on updated WBS / Work Package Plan, the facility optimizations, and revisions to the indirect scope of work, plus updated unit, and material / equipment cost.

3.4.2. Environmental Discipline

The Environmental discipline shall:

- Prepare an Environmental Management Plan.
- Prepare a robust Environmental Registration Document.

3.4.3. Engineering Discipline

The engineering discipline shall:

- Prepare and implement an Engineering Management Plan, including L4 Engineering Schedule and Schedule Basis.

Key Engineering activities to be undertaken are:

- Prepare facility Scope of Work
- Preliminary Engineering and Design Optimizations
- Preparation of MTOs

- Update the Facility Scope of Work

3.4.4. Procurement Discipline

The Procurement discipline shall prepare and implement a *Procurement Management Plan*, Key procurement activities are:

- Issue vendor packages and obtain quotations / delivery timelines for Long Lead Items.
- Work with PM and Construction discipline to document the contracting strategy.
- Work with the Owner to finalize standard contract documentation and procurement processes.
- Preparation of a L3 Bid Schedule and Schedule basis.

3.4.5. Construction Discipline

The Construction team shall prepare and implement a *Construction Management Plan*. Key aspects of the plan are:

- Define the Path of Construction[3] and optimize the construction sequencing.
- Prepare the L3 Construction Schedule and Basis.
- Review and update the indirect direct scope of work to reflect current market conditions and the selected project delivery model.
- Develop a Work Packaging Plan.

[3] The Path of Construction is defined as the optimal sequencing of the building of a facility, developed by Construction, Engineering and Project Management Subject Matter Experts (SMEs), typically working backwards from the “end state”.

4. PROJECT-SPECIFIC RISKS

4.1. ENVIRONMENTAL RISK

A review of the federal and provincial Environmental Regulatory and Approval context for the proposed NL Hydro Generation Expansion prospects is included in **APPENDIX D**.

4.2. SOCIOECONOMIC INFLUENCES

Socioeconomic influences for the proposed prospects are also discussed in **APPENDIX D**.

4.3. MARKET CONDITIONS

As the project is relatively small by hydro standards, Contractor Capability / Availability should not be an issue (there are several local contractors who could undertake this work).

4.4. LONG-LEAD ITEMS RISK

Due to the small size of the Turbine / Generator, Supply Chain issues should be manageable and are unlikely to seriously impact the schedule.

4.5. TECHNICAL RISK

4.5.1. Hydrotechnical

It is recommended that the hydrology be updated to reflect current data and forecasted climate considerations.

4.5.2. Geotechnical

Should the Hydrotechnical review result in a change to the project Power and Energy configuration, then updates to the scheme will likely necessitate a detailed geotechnical investigation. The existing geotechnical information was not available for this screening & ranking assessment, further comment would not be warranted, although a Google Earth review indicates the present of cut lines, access trails, etc., so it would appear that an extensive program was undertaken for the present scheme.

4.5.3. Technical Complexity

Generally the project is not technical complex. In-depth Environmental Mitigations will be required, however, and these will impact cost and schedule. Numerous stream crossings are required, most of which will be temporary, and other temporary diversions will be necessary for construction. While there are a large number a earthworks-related facilities, the volume of earthmoving will be small.

The North Access to the project area will probably have the least impact, as there appears to be a forestry-type road to within 3 km of the site.

4.6. PROJECT COST RISK

Like Prospect 3: Island Pond, the largest risk factors to cost (and, in some respects, to schedule) will be volatility in fuel costs, contractor capacity (availability of human resources, both technical and construction), and the potential for excessive cost escalation due to local market conditions and global factors.

4.7. PROJECT SCHEDULE RISK

The 2018 Hydro report identified environmental and regulatory approvals; detailed design and tendering of the water-to-wire (W2W) package; design, manufacturing and delivery of the W2W equipment; and W2W equipment installation and commissioning are key schedule risks. These remain valid in 2022.

APPENDIX C

PROSPECT 5

PORTLAND CREEK HYDROELECTRIC DEVELOPMENT

PROSPECT OVERVIEW, GAP ANALYSIS & RISKS

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1. PROSPECT 5 OVERVIEW: PORTLAND CREEK HYDROELECTRIC DEVELOPMENT

1.1. LOCATION AND BACKGROUND

The proposed Portland Creek Hydroelectric Development ("Portland Creek") is located near Daniel's Harbour on the west side of the Great Northern Peninsula on the island of Newfoundland, specifically on Main Port Brook, a tributary of Portland Creek (see **FIGURE C5.1**). A pre-feasibility study for the development was completed in 1987, followed by a full Feasibility study in 2007.[1]

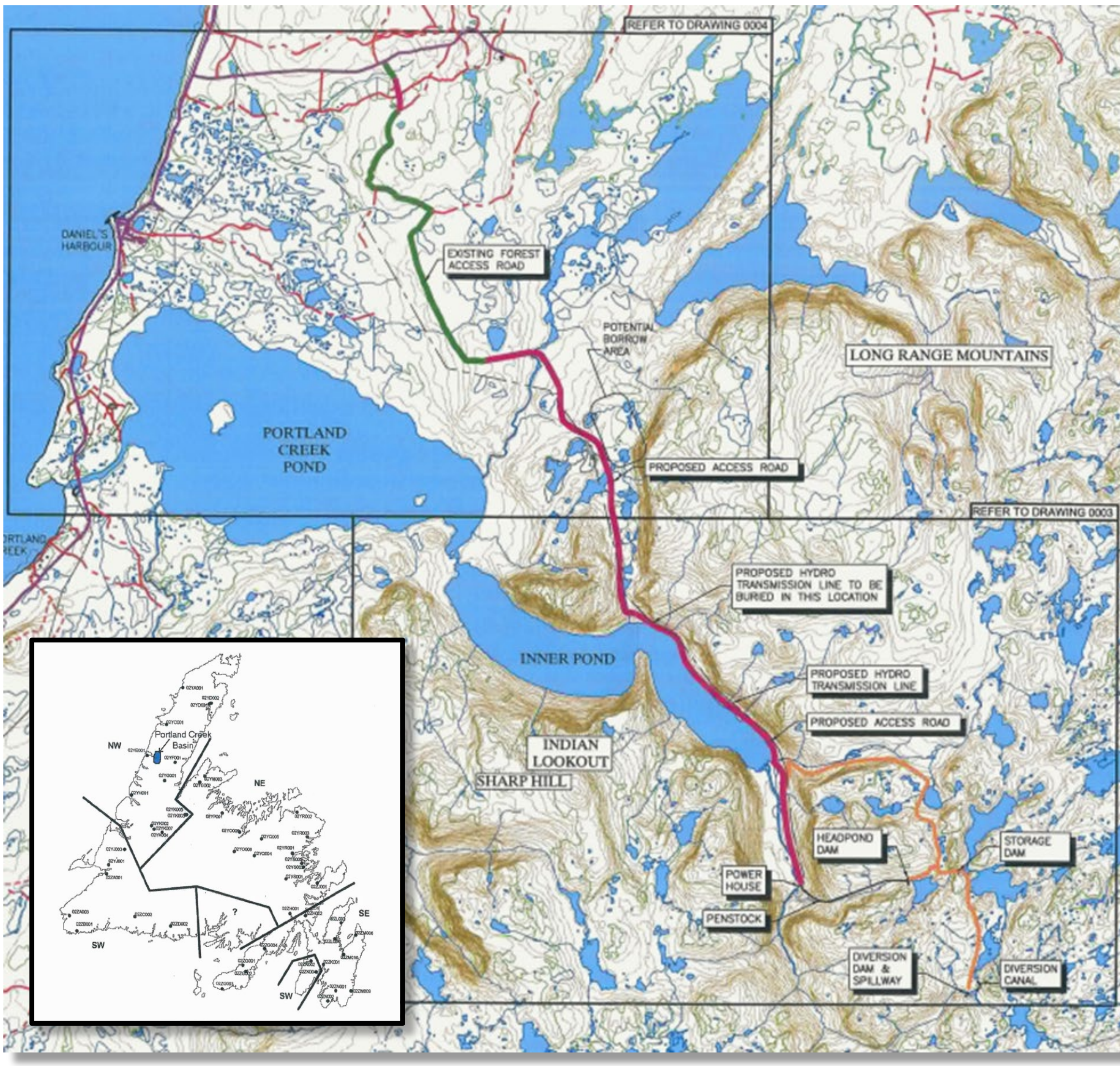


FIGURE C5.1 PROJECT LOCATION – PORTLAND CREEK

[1] *Feasibility Study for Portland Creek Hydroelectric Project*. SNC-Lavalin Project No. 722736, January 2007.

1.2. PROJECT DESCRIPTION

Several drawings from the 2007 Feasibility Study are reproduced in **FIGURE C5.3** on the following page. The proposed project consists of the following key components.

- Generation Facility
- Control Structures
- Water Conveyance System
- Transmission Facilities

The Generation Facility consists of a 17 m x 14 m Powerhouse with a concrete substructure and steel superstructure with two (2) Pelton Turbines Generator, each with a rated output of 11.5 MW.

Control Structures include a 110 m long concrete gravity Diversion Dam and overflow spillway with a crest length of 70 m and maximum height of 12 m; a 320 m long Diversion Canal that transfers flows from a Diversion Pond into the main storage reservoir; a 45 m long concrete gravity Storage Dam including a flow regulating structure fitted with a trash rack; and a 143 m long Headpond Dam with maximum height of 15 m, including a power intake structure fitted with a trash rack and an overflow spillway.

The Water Conveyance System consists of a 2900 m long, 1.52 m diameter penstock to convey water from the Headpond Dam to the Powerhouse.

Transmission Facilities in the original concept consist of a 27 km long 66 kV transmission line connecting a 66 kV switchyard to the existing substation at Peter's Barren.

1.3. PROPOSED LAYOUT

In the 2007 Feasibility Study, site access was planned from the Daniel's Harbour Mine Road, approximately 18 km from the proposed Powerhouse. An additional 12 km of access road would have been required through the watershed, but, today, the access road built for the new Labrador Island Link (LIL) eliminates the need to build access to Daniel's Harbour. The revised layout is summarized in **FIGURE C5.2** below.

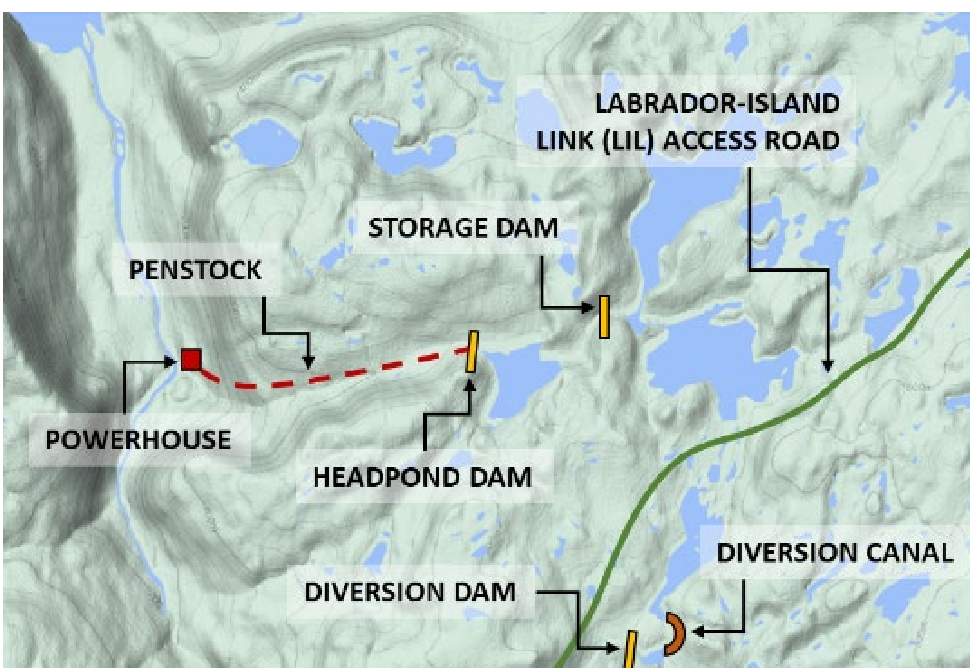


FIGURE C5.2 PORTLAND CREEK LAYOUT INCLUDING NEW LIL ACCESS ROAD

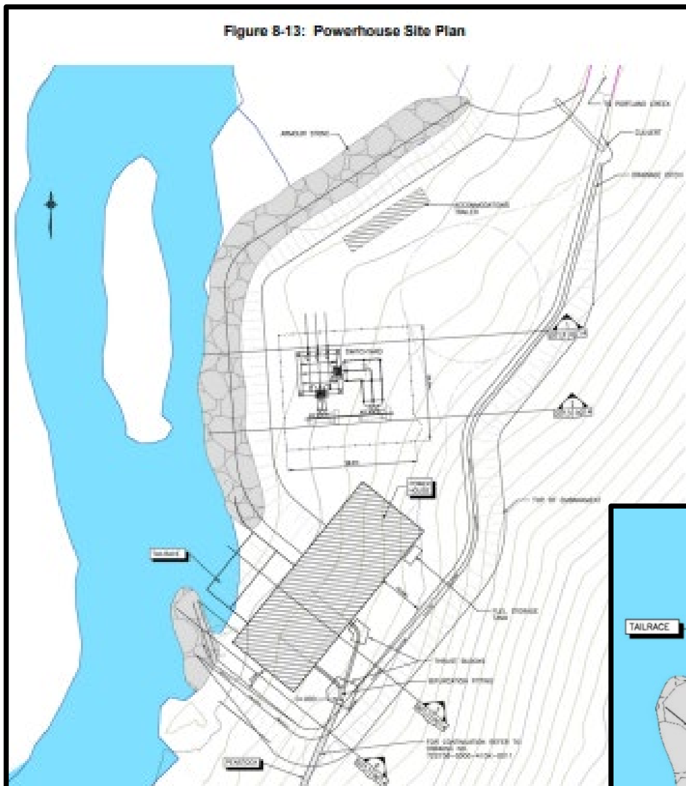
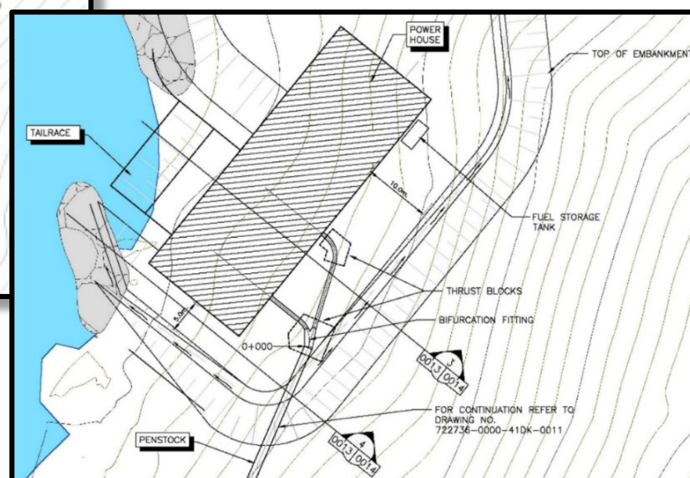


Figure 8-13: Powerhouse Site Plan



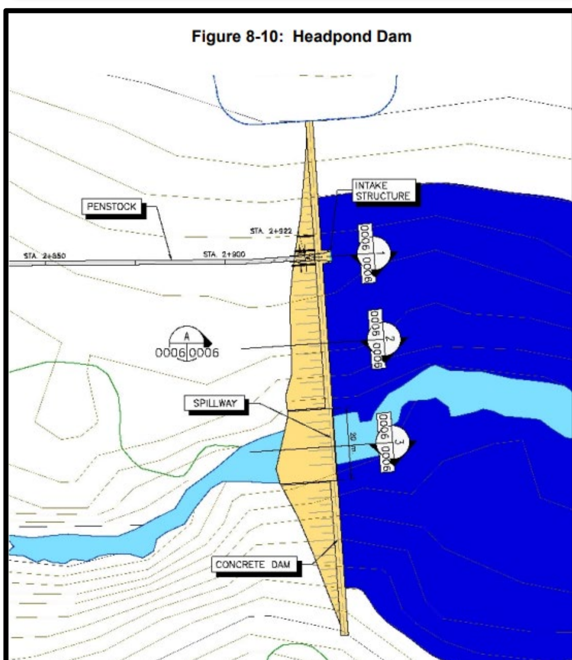


Figure 8-10: Headpond Dam

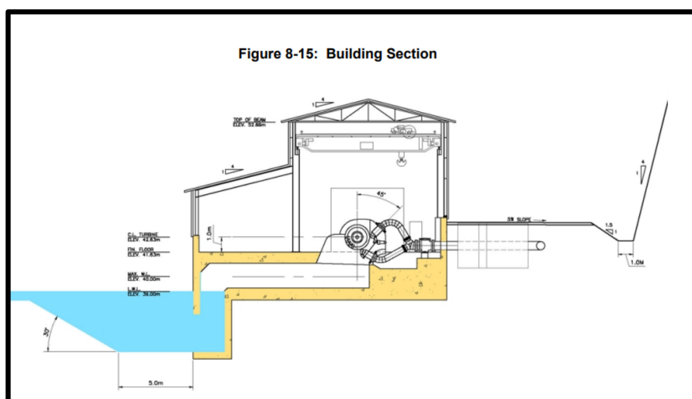


Figure 8-15: Building Section

FIGURE C5.3 PORTLAND CREEK DEVELOPMENT DRAWINGS FROM 2007 FEASIBILITY STUDY

1.4. COST ESTIMATE TO BUILD PROJECT (ESCALATED TO YE-2022)

In 2018, Hydro updated the cost estimate[2] for Portland Creek by escalating a 2012 estimate update[3] by SLI from the 2007 Feasibility Study. Here, 2018 costs were escalated to YE-2022 as shown in **TABLE C5-1**.

TABLE C5-1: PORTLAND CREEK COST ESTIMATE ESCALATED TO YE-2022

COST ITEM	AMOUNT	NOTES
Material Supply	$3,245,800	From 2012 estimate escalated to 2018 by Hydro.
Labour	$17,344,700	" "
Consultant	$21,674,200	" "
Contract Work	$154,770,300	" "
Other Direct Costs	$1,083,700	" "
Interest	$24,071,400	" "
Contingency	$39,623,700	" "
Total Cost (2018)	$261,813,751	" "
Escalation calculation (2018-2022)	132.5%	2019: 2.2% 2020: 1.2% 2021: 11.4% *Statistics Canada Construction Cost Index (CCPI)*
		2022: 15% *Projection by SLI Cost Estimating Department*
2022 TOTAL ESCALATED COST	**$346,903,220**	
AACE Estimate Accuracy (Index of 1 = +10% / -5%)	+50% / -25%	Class 5 accuracy index range = 4 to 20 Index for this estimate assumed = 5

[2] *Island Pond Hydroelectric Development*. NL Hydro, August 29, 2018.

[3] *Portland Creek and Island Pond Hydroelectric Projects Update Cost Estimates*. SNC-Lavalin 501325-40ER-0001-PA, May 2012.

1.5. KEY TECHNICAL METRICS

The following key technical metrics were developed from the above information and used in the Screening and Ranking Process.

- Power (MW Installed): Two (2) Pelton Turbine Generators with Installed Capacity 23 MW
- Cost per MW of Power (escalated to YE-2022): $15.1 million / MW
- Overall Project Duration : 6.3 Years
    - Planning Timeline: 3.2 Years
    - Execution (Construction) Timeline: 3.1 Years
    - Less Overlap Planning/Execution: 0 Years
    - Overall Development Timeline: 6.3 Years

2. EXISTING PROJECT INFORMATION DATA GAP

2.1. OVERVIEW

To prepare the 2007 Feasibility Study, an initial Field Program was undertaken and access options were assessed. The key recommendation pertaining to this Gap Analysis (from Appendix D of that study) is that further Field Investigation work is required, estimated to cost in the range of $400,000 (2007 dollars) and including the following tasks.

Assessment of the HADD requirements and solutions.

Additional geotechnical work in the Powerhouse area.

Further confirmation of Borrow Pit and Aggregate sources.

The initial access resulted in the upgrading and new construction of approximately 40 km of roadway. Today, the Labrador-Island Link (LIL) Access Road passes within 0.5 km of the division structure and only access to the remaining structure plus the powerhouse is required, saving considerable capital expenditure.

Therefore, in terms of the preparing a Scope of Work for a FEEP study, the above-noted information has been accounted for in updating to the cost estimate and schedule.

In addition, a hydrological review undertaken as a part of this study indicates that a new review should be undertaken to account for the potential impact of climate change. Therefore, an update to the Project Definition statement is also included.

2.2. DATA GAP

To advance this work to a *Front-End Execution Planning (FEEP) standard*, the following gaps remain (see **TABLE C5-2**).

TABLE C5-2: GAP ANALYSIS FOR PROSPECT 5: PORTLAND CREEK

STAGE 1: PROJECT DEFINITION		
RESPONSIBLE GROUP	**DELIVERABLE**	**REQUIREMENTS TO ADDRESS GAP**
Owner / Corporate	**PROJECT DEFINITION STATEMENT**	Update Hydrology, then identify Power / Energy options.. Selection of preferred Power / Energy Option. Identify preferred option for site access and transmission line routing. Update Project Scheme.
	PROJECT CHARTER	Develop Project Charter as per standard for internal approval and sign-off, including recommended Contracting Strategy. Develop the Environmental Management Strategy. Approve FEEP-Stage Budget, Deliverables List, and Milestone Schedule.
STAGE 2: FEEP		
RESPONSIBLE GROUP	**DELIVERABLE**	**REQUIREMENTS TO ADDRESS GAP**
Project Management	**PROJECT EXECUTION PLAN (PEP)**	
	Scope of Work	Update based on optimized preliminary designs.
	Project Management Strategy	Key elements of the execution strategy will need to be reviewed and updated based on the selected Project Delivery Model.
	Project Controls Strategy	Determine how cost estimating and schedule development activities are going to be coordinated.
	Health & Safety Strategy	Prepare HS&S Project Strategy.
	QA / QC Strategy	Prepare Quality Management Strategy.
	PROJECT CONTROLS DOCUMENTATION	
	Cost Estimate (Class 4 / Class 3)	Update based on updated contracting strategy, schedule, design optimizations, updated unit costs and costs for Long-Lead items and the cost of implementing the Environmental Protection Plan.
	Schedule	Prepare L2 based on updated MTOs, Timelines for long-lead items, Environmental timelines, Construction Sequencing, and Contracting Strategy.
	ENVIRONMENTAL MANAGEMENT PLAN	Based on the Environmental Management Strategy, develop a detailed Management Plan.

Environmental Management	**PROJECT REGISTRATION / EIS**	Prepare Robust Environmental Registration Document
Engineering	**FACILITY SCOPE OF WORK**	Update the Facility Scope of Work document based revised project scheme and the optimized design.
	PRELIMINARY ENGINEERING	Update / optimize the preliminary engineering based on the revised scheme, including a review of the penstock access road to determine its suitabil for use a main access road to the powerhouse.. Prepare Vendor Packages for the Long Lead Items.
	FIELD INVESTIGATIONS SOW	Prepare Field Program Scope of Work.
	DESIGN OPTIMIZATIONS	Based on the results of the field investigations, optimize the preliminary designs. Prepare Preliminary EWPs.
	UPDATED PRELIMINARY ENGINEERING	Develop the optimized designs into preliminary EWPs.
	MTOs	Update the MTOs and incorporate quantities into the cost estimate and schedule duration calculations.
Supply Chain Management	**CONTRACTING STRATEGY**	Work with PM and Construction discipline to document the Contracting Plan.
	BID & EVALUATION PLAN	Prepare a plan which documents standard contract documentation, the bid management process, including bid evaluation plans, approval authorities, etc..
	LONG-LEAD ITEMS VENDOR PACKAGES	Issue vendor packages and obtain quotations / delivery timelines for Long Lead Items.
	FIELD INVESTIGATIONS PLAN	Issue PO for Field Investigation Activities.
Construction	**CM STRATEGY**	Prepare and Implement a Field Investigation Program Execution Plan based on the scope of work prepared by engineering. Prepare Construction Management Plan based on the Contracting Strategy
	PATH OF CONSTRUCTION	Undertake Construction Planning activities necessary to develop the Path of Construction (sequencing).
	CONSTRUCTION SCHEDULE	Based on the Path of Construction, update construction schedule.

3. SCOPE OF WORK TO COMPLETE FEEP STAGE

3.1. PURPOSE

This section outlines the scope of work necessary to update Project Definition Stage and then prepare the FEEP-stage scope of work. This assumes that the Hydrotechnical review will redefine the Power and Energy configuration and, therefore, reopen a Project Scheme review. A Field Investigation is proposed to be undertaken during Project Definition such that the FEEP stage can be executed in an uninterrupted workflow.

3.2. OWNER'S KEY INPUTS

The key input required here is Hydro's internal assessment of its projected power and energy needs, followed by the preparation of a Project Charter, approved Environmental Management Strategy, and approved FEEP Stage Budget, Deliverables List, and Milestone Schedule.

3.3. PROJECT DEFINITION STATEMENT UPDATE SCOPE OF WORK

The following key activities are included.

1. Development of a revised access plan.
2. Review / update of existing preliminary designs, based on the revised hydrology and Power / Energy requirements, including a review of the access road along the Penstock to determine if it can serve as the main access to the Powerhouse.
3. Plan and implement a Field Investigation Program.
4. Revise activities 1. and 2.
5. Prepare a Class 5 Cost Estimate.
6. Preparation of documentation to support the Environmental Management Strategy.

3.4. PROJECT TEAM FEEP-STAGE SCOPE OF WORK

3.4.1. Project Management Discipline

The key Project Management Team deliverable is a *Front-end Execution Plan (FEEP)*, which incorporates the following key documentation.

- Based on the scope of work outlined in existing documentation, and the design optimizations to be prepared (see **3.3.3. Engineering** below), prepare an updated *Project Scope of Work Document (SOW)* and *Work Breakdown Structure (WBS)*.
- Based on the updated SOW, prepare a Front-End Execution Plan (FEEP). A key part of the plan is the Contracting Strategy, which includes a Project Delivery Model, Compensation Model, and Sourcing Strategy.
- Based on the SOW and WBS, develop the following key sections of the FEEP:
  - Project Management Approach
  - Project Controls Strategy
  - Health, Safety and Security
  - Quality Management Strategy
- Coordinate the preparation of the following by other disciplines.

  - Environmental Management Plan
  - Engineering Management Plan
  - Procurement Management Strategy
  - Contracting Strategy
  - Construction Management Strategy
  - Construction Sequencing Plan
  - Work Packaging Plan
- Coordinate the preparation of the following Project Controls Documentation.
  - Using the existing schedule data, revised WBS and Work Packaging Plan, develop and optimize a *L3 Project Schedule and Schedule Basis*, incorporating EIA and Long Lead timelines provided by vendors. The *Level 3 (L3) Project Schedule should include*:
    - L4 Project Management Schedule and Schedule Basis.
    - L4 Environmental Management Schedule and Schedule Basis.
    - L4 Engineering Management Schedule and Schedule Basis.
    - L3 Bid Stage Schedule and Schedule Basis.
    - L3 Construction Schedule and Schedule Basis with Monte Carlo Simulation which incorporates updated long lead item delivery timelines.
  - *Class 3 Cost Estimate, Estimate Basis, and Risk Analysis*, e.g., Monte Carlo Simulation. Update the existing Cost Estimate based on updated WBS / Work Package Plan, the facility optimizations, and revisions to the indirect scope of work, plus updated unit, and material / equipment cost.

3.4.2. Environmental Discipline

The Environmental discipline shall:

- Prepare an Environmental Management Plan.
- Prepare a robust Environmental Registration Document.

3.4.3. Engineering Discipline

The engineering discipline shall:

- Prepare and implement an Engineering Management Plan, including L4 Engineering Schedule and Schedule Basis.

Key Engineering activities to be undertaken are:

- Prepare Facility Scope of Work.
- Preliminary Engineering and Design Optimizations.
- Preparation of MTOs
- Update the Facility Scope of Work.

3.4.4. Procurement Discipline

The Procurement discipline shall prepare and implement a Procurement Management Plan, Key procurement activities are:

- Issue vendor packages and obtain quotations / delivery timelines for Long Lead Items.
- Work with PM and Construction discipline to document the contracting strategy.
- Work with the Owner to finalize standard contract documentation and procurement processes.
- Preparation of a L3 Bid Schedule and Schedule basis.

3.4.5. Construction Discipline

The Construction team shall prepare and implement a Construction Management Plan. Key aspects of the plan include:

- Define the Path of Construction[4] and optimize the construction sequencing.
- Prepare the L3 Construction Schedule and Basis.
- Review and update the indirect direct scope of work to reflect current market conditions and the selected project delivery model.
- Develop a Work Packaging Plan.

[4] The Path of Construction is defined as the optimal sequencing of the building of a facility, developed by Construction, Engineering and Project Management Subject Matter Experts (SMEs), typically working backwards from the “end state”.

4. PROJECT-SPECIFIC RISKS

4.1. ENVIRONMENTAL RISK

A review of the federal and provincial Environmental Regulatory and Approval context for the proposed NL Hydro Generation Expansion prospects is included in **APPENDIX D**.

4.2. SOCIOECONOMIC INFLUENCES

Socioeconomic influences for the proposed prospects are discussed in **APPENDIX D**. This Brownfield project is remote and socioeconomic influences will likely be positive.

4.3. MARKET CONDITIONS

The project start date is assumed to be some years away, so it is difficult to comment on market conditions.

4.4. LONG-LEAD ITEMS RISK

The selected T/G selection is not difficult to procure and will not be the critical path for construction.

4.5. TECHNICAL RISK

4.5.1. Hydrotechnical

The hydrology for Portland Creek is out of date. The hydrology should be updated to a common time base with other projects under review so that a valid comparison can be made between projects. This should be used to update the power and energy study, which will also allow confirmation of the main project characteristics (dam height and type, spillway capacity, installed capacity, etc.).

The potential for sudden torrents on rivers and streams in the area should be investigated to understand risk.

4.5.2. Geotechnical

The 2007 feasibility study had proposed an extensive geotechnical program that was significantly reduced and that study was to make use of previous information. There is a risk that the assumptions made were based on information that was not valid. It is important that adequate geotechnical field investigations be undertaken to determine if changes are required to the assumptions and designs from the 2007 study.

The 2007 study stated that the material excavated from the diversion canal should be suitable for concrete aggregate, but testing has not been done to validate this assumption, nor the suitability of other potential aggregate sources identified. The study did state that there are abundant materials, should they be suitable.

The previous study commented that the area is well-suited for a concrete gravity dam, but that foundation grouting will be required. Additional information is required to help assess the extent of grouting that might be required to adequately seal the foundations in the required locations.

The 2007 study geotechnical information provided the assumption that 1H:4V for excavation in rock, but with further investigation on the strength of the rock, a steeper slope could be possible. This could result in cost savings to the project. Adequate geotechnical information is required to assess this.

The geotechnical section of the 2007 study commented on the risk of avalanches, river torrents (during extreme rainfall) and areas of Karst topography, which may affect construction access and the penstock route.

An initial review of potential acid generating rock was examined as part of the previous study, but this should be validated as part of any further geotechnical investigations.

4.5.3. Technical Complexity

Siting of dams, powerhouse and penstock route should be reviewed and optimized with updated geotechnical information and information from updated power and energy study.

4.6. PROJECT COST RISK

This project is not technically complex nor difficult to construct. Sound planning and engineering, with a sanction estimate based on bid prices, should address the risk of cost or schedule overruns.

4.7. PROJECT SCHEDULE RISK

It is assumed for construction schedule purposes that no work will take place in the winter, except T/L construction to Peter's Barrens. If this must change, considerable cost and schedule risk will result.

APPENDIX C

PROSPECT 6

EXPLOITS RIVER HYDROELECTRIC DEVELOPMENTS

PROSPECT OVERVIEW, GAP ANALYSIS & RISKS

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1. PROSPECT 6 OVERVIEW: EXPLOITS RIVER HYDROELECTRIC DEVELOPMENTS

1.1. LOCATION AND BACKGROUND

Prospect 6 includes two (2) subprojects on the Exploits River at the locations of Red Indian Falls and Badger Chute (see **FIGURE C6.1**), which have long been recognized as potential hydro resources. Both subprojects have been studied at a high level, with the most recent reviews dating from 2018[1] and 2005.[2] The 2018 report suggests that both projects are "reasonably viable", but with the following caveat.

> *"(T)here are significant concerns surrounding the potential environmental, socioeconomic and archeological impacts associated with these developments. The full extent of these impacts and their associated mitigation costs will need to be understood prior to the completion of an accurate assessment. It is uncertain at this time as to whether or not either of these alternatives would receive approval as part of the Environmental Assessment Process."*

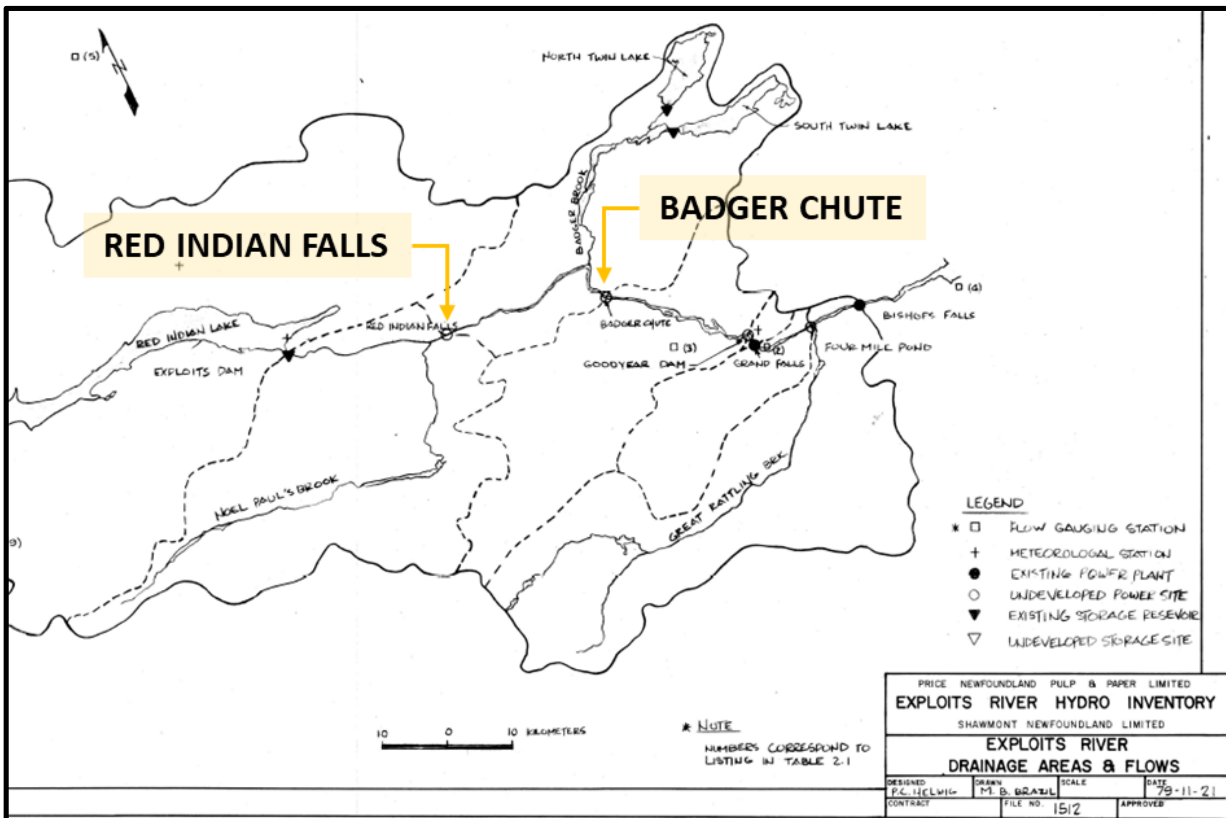

FIGURE C6.1 PROJECT LOCATION – EXPLOITS RIVER PROSPECTS

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[1] *Exploits River Hydroelectric Generation Expansion*. NL Hydro, September 5, 2018.

[2] *Exploits River Hydro Potential (Red Indian Falls, Badger Chute & Four Mile Pond) Preliminary Project Assessment*. NL Hydro, January 28, 2005.

1.2. REDUCED STUDY SCOPE FOR PROSPECT 6

Based on Hydro's 2018 assessment of the Exploits River subprojects and the Project Team's review of available information, it was determined that Prospect 6 did not warrant the same level of investigation as the other prospects. Considerable technical and environmental work (at high cost) will be required before the economic viability can be properly assessed. There also appears to be considerable risk in obtaining social licence for the subprojects, given the concerns surrounding the environmental, socioeconomic and archeological impacts associated with the developments.

This level of study will require considerable upfront expenditure. While it is likely that many of the issues can be mitigated, it is more likely that other alternatives on the island, particularity on the southwestern side of the Great Northern Peninsula, present viable alternatives with considerably less environmental impact and an improved opportunity of obtaining social licence.

1.3. PROJECT DESCRIPTION

Red Indian Falls would see the construction of a 42 MW hydroelectric generating facility 20 km upstream of the Town of Badger. Generation would be achieved through the use of two (2) vertical Francis turbines.

Badger Chute consists of the construction of a 24 MW hydroelectric generating facility 7 km downstream of the Town of Badger. Generation would be achieved with three (3) vertical Francis turbines.

It was noted in the 2018 study that the development of Badger Chute has the potential to increase ice formation and elevate the risk of flooding for the Town of Badger. However, the construction of Red Indian Falls would, conversely, reduce (if not eliminate) the flooding problem. For this reason, Badger Chute would need to be completed in conjunction with (or closely following on the completion of) Red Indian Falls. This condition would likely further complicate obtaining social licence for the developments.

1.4. KEY TECHNICAL METRICS

The following key technical metrics were developed from the available information on the subprojects and used in the Screening and Ranking Process.

Red Indian Falls

- Power (MW Installed): Two (2) x Francis Turbines delivering 42 MW
- Cost (escalated to YE-2022): $329,444,713
- Cost per MW of Power (escalated to YE-2022): $13.7 million / MW

Badger Chute

- Power (MW Installed): One (1) x 62.2 MW Pelton Turbine
- Cost (escalated to YE-2022):: $520,237,859
- Cost per MW of Power (escalated to YE-2022): $12.4 million / MW

2. EXISTING PROJECT INFORMATION DATA GAP

For the Exploits River prospects (Red Indian Falls and Badger Chute), the normal planning and engineering activities for Project Definition and Front-End Execution Planning (FEEP), as detailed for the other prospects, would also be applicable.

However, the level of planning and engineering required to support the Environmental Assessment Process for these prospects will likely be very significant in terms of definition and scoping, but also very challenging in determining the cost and schedule implications. This is beyond the scope of the current study. Therefore, the scope of work to undertake the Project Definition and FEEP stages cannot be estimated at this time.

It is suggested that a Project Definition Statement be prepared for each Exploits River prospect by a joint team of planners, engineers and environmental SMEs. A full understanding of the potential impacts is necessary to assess the FEEP scope of work.

APPENDIX D

ENVIRONMENTAL APPROVALS AND PERMITTING

TABLE OF CONTENTS

1. OVERVIEW

APPENDIX D is a review of the federal and provincial Environmental Regulatory and Approval context for the proposed NL Hydro Generation Expansion Prospects. For the purposes of the regulatory approval process, the prospects under consideration have been grouped into two (2) broad categories.

Brownfield Projects (expansion of generating capacity of existing facilities)

1. Bay d 'Espoir (BDE) Unit 8
2. Cat Arm Addition

Greenfield Projects (development and construction of new facilities)

3. Island Pond
4. Round Pond
5. Portland Creek (plus the potential for adjacent watersheds, referred to as Northern Peninsula West)
6. Exploits River
   - Red Indian Falls
   - Badger Chute

Each project would have to undergo a provincial Environmental Assessment ("EA") under the Newfoundland and Labrador *Environmental Assessment Regulations* (NLR 54/03) issued under the *Environmental Protection Act* (SNL 2002, c. E-14.2). In addition, various federal and provincial environmental permits will be required for each project, as discussed below.

2. PROVINCIAL ENVIRONMENTAL ASSESSMENT (EA)

2.1. OVERVIEW

Development of a hydroelectric generating plant or expansion of an existing plant both constitute “designated undertakings” listed in Part III of the *Environmental Assessment Regulations*. As such, both brownfield and greenfield projects must be registered for environmental assessment because they include multiple activities listed under “Utilities” (clause 34) of the Regulations.

> 34.(1) An undertaking that will be engaged in electric power generation and the provision of structures related to that power generation, including
>
> (a) the construction of dams and associated reservoirs where the area to be flooded is more than 50 hectares;
>
> (b) the excavation of reservoirs where the area to be flooded is more than 50 hectares;
>
> (c) inter-basin or intra-basin water transfers;
>
> (d) the construction of hydroelectric power developments with a capacity of more than one megawatt shall be registered.
>
> *[portions deleted]*
>
> (2) An undertaking that will be engaged in the construction of new electric power transmission lines or the relocation or realignment of existing lines where a portion of a new line will be located more than 500 metres from an existing right of way shall be registered.

Any hydroelectric project currently under consideration, whether brownfield or greenfield, will “trigger” various aspects of the EA process and permitting requirements based on reservoir size, generating capacity, and other characteristics unique to each project. Trigger factors are summarized in **TABLE D-1.**

Within 45 days of receiving a registration, the Minister will advise the proponent of the decision on the undertaking. The following are possible decisions.

- Undertaking released (45 days from registration).
- Environmental Preview Report (EPR) (estimated 1.5 years from registration).
- Environmental Impact Statement (EIS) (estimated 3-3.5 years from registration).
- Undertaking rejected

Based on conversations with Rod Healey, Manager Environment Operations with NL Hydro, the requirements for the proposed “brownfield” projects are likely to consist primarily of permit applications and approvals. These projects are likely to be “released” from further assessment under the provincial EA process. The anticipated length from registration to approval, including required permit approvals, is approximately six (6) months.

The “greenfield” projects may be assessed under either an EPR or EIS process. However, instead of submitting a basic registration document and awaiting the Minister’s decision regarding whether to proceed with an EPR or EPS, NL Hydro’s approach in recent years has been to submit a “robust” registration document. This approach may lead to a more rapid approval, as detailed below.

TABLE D-1 SUMMARY OF ENVIRONMENTAL ASSESSMENT TRIGGER ACTIVITIES

TRIGGER ACTIVITY	PROSPECT 1 BDE UNIT 8	PROSPECT 2 CAT ARM	PROSPECT 3 ROUND POND	PROSPECT 4 ISLAND POND	PROSPECT 5 PORTLAND CREEK	PROSPECT 6: EXPLOITS RIVER BADGER CHUTE	PROSPECT 6: EXPLOITS RIVER RED INDIAN FALLS
Construction of dams and reservoirs > 50 ha (0.5 km²)	No new construction	No	Yes (800 ha)	Yes	Yes	Yes	Yes
Excavation of reservoirs > 50 ha (0.5 km²)	No	No	No	No	No	No	No
Inter-basin or intra-basin water transfers	No (existing)	No	No	No	No	No	No
Construction of hydroelectric power developments > 1 MW	Yes 150 MW increase	Yes 68.2 MW increase	New construction 18 MW	New construction 36 MW	New construction 23 MW	New construction 24 MW	New construction 42 MW
Construction of new electric power lines or relocation of existing lines where a portion of a new line will be > 500 m from an existing ROW	Possible (to be determined based on design of line from existing powerhouse to switchyard; Anticipated distance < 2 km)	120 km transmission line possibly planned, but no trigger if within 500 m of existing right-of-way	44 km transmission line planned	18 km transmission line planned	25.5 km transmission line planned	20 km transmission line planned	50 km transmission line planned

2.2. ROBUST REGISTRATION DOCUMENT

Based on a review of projects currently listed in the Newfoundland and Labrador Environmental Assessment Registry (https://www.gov.nl.ca/ecc/env-assessment/projects-list/) and conversations with Rod Healey, NL Hydro's approach to environmental assessment for its projects in recent years has been to submit a robust registration document in lieu of a basic registration followed by a ministerial decision and issuance of Terms of Reference for an EPR or EIS process.

Under this approach, the Registration document itself includes much of the content that would be included in the Terms of Reference for either an EPR or EIS, including results of ecological field studies where applicable (e.g., fish presence and fish habitat surveys, avian nesting and migration studies, species at risk and wildlife use studies). Proposed standard operating procedures, mitigation measures to reduce environmental impact, and compensation measures where impacts are unavoidable are also submitted as part of the registration document.

Because content of this nature is anticipated to be required for an EPR or EIS of any major utility project, submitting this material in advance increases the likelihood that the projects will be "released" from further assessment (i.e., approved to proceed) following the 45-day ministerial review period.

2.3. ALTERNATIVE APPROACH: CLASS EA

Under section 18 of the Newfoundland and Labrador *Environmental Assessment Regulations*, the minister may establish requirements for a class environmental assessment. This approach has been implemented in Ontario, where the Ontario Waterpower Association has obtained a Class Environmental Assessment for Waterpower Projects (currently 9th edition, 2022) which covers all hydroelectric developments in Ontario. Similarly, a class EA has been implemented for Minor Transmission Facilities in Ontario.

Pursuing this approach may be beneficial for the NL Hydro, as it would provide blanket EA approval for all NL Hydro Generation Expansion projects currently under consideration, as well as all future projects of a similar nature. Ecological surveys of individual development sites would still need to be conducted but known impacts and mitigation measures associated with the projects would be documented and approved in advance.

3. FEDERAL IMPACT ASSESSMENT ACT

The proposed project does not trigger application of the federal *Impact Assessment Act* (S.C. 2019, c. 28). The federal act generally applies to larger-scale hydroelectric projects and transmission lines that cross provincial or international boundaries, as designated in the *Physical Activities Regulations* (SOR/2019-285) under the Act. A summary of the requirements in the *Physical Activities Regulations*, by section, and why they do not apply to the project under consideration is presented in **TABLE D-2**.

NOTE: For Prospect 2, the planned addition of a 68.2 MW generator to the existing Cat Arm hydroelectric facility represents a 50% expansion of generating capacity relative to its current capacity (136.4 MW), and the planned 204.6 MW capacity exceeds the 200 MW threshold. As such, the planned configuration would trigger application of the Impact Assessment Act through section 43 (a) of the Physical Activities Regulations, as summarized in **TABLE D-2** below. The proponent is advised to consider reducing the planned capacity increase if it wishes to remain below the section 43 (a) criteria.

TABLE D-2 SUMMARY OF FEDERAL ENVIRONMENTAL ASSESSMENT PHYSICAL ACTIVITIES REGULATIONS

TRIGGER ACTIVITY AND SECTION NUMBER	PROSPECT 1 BDE UNIT 8	PROSPECT 2 CAT ARM	PROSPECT 3 ROUND POND	PROSPECT 4 ISLAND POND	PROSPECT 5 PORTLAND CREEK	PROSPECT 6: EXPLOITS RIVER BADGER CHUTE	PROSPECT 6: EXPLOITS RIVER RED INDIAN FALLS
ELECTRICAL TRANSMISSION LINES AND PIPELINES							
39 The construction, operation, decommissioning and abandonment of either of the following. **(a): a new international electrical transmission line with a voltage of 345 kV or more that requires a total of 75 km or more of new right of way;**							
	No. Not international.	No. Not international.	No. Not international.	No. Not international.	No. Not international.	No. Not international.	No. Not international.
(b): a new interprovincial power line designated by an order under section 261 of the Canadian Energy Regulator Act.							
	No. Not interprovincial.	No. Not interprovincial.	No. Not interprovincial.	No. Not interprovincial.	No. Not interprovincial.	No. Not interprovincial.	No. Not interprovincial.
RENEWABLE ENERGY							
42 The construction, operation, decommissioning and abandonment of one of the following. **(a) a new hydroelectric generating facility with a production capacity of 200 MW or more;**							
	No. Not a new facility.	No. Not a new facility.	No. Planned capacity 18 MW < 200 MW	No. Planned capacity 36 MW < 200 MW	No. Planned capacity 23 MW < 200 MW	No. Planned capacity 24 MW < 200 MW	No. Planned capacity 42 MW < 200 MW
43 The expansion of one of the following. **(a) an existing hydroelectric generating facility if the expansion would result in an increase in production capacity of 50% or more and a total production capacity of 200 MW or more;**							
	No. Current capacity 450 MW Proposed increase 154 MW Increase = 34.2% (< 50%) Total 604 MW	Yes. Current capacity 136.4 MW Proposed increase 68.2 MW Increase = 50% (< 50%) Total 204.6 MW	No. Not an expansion.	No. Not an expansion.	No. Not an expansion.	No. Not an expansion.	No. Not an expansion.

Continued

TRIGGER ACTIVITY AND SECTION NUMBER	PROSPECT 1 BDE UNIT 8	PROSPECT 2 CAT ARM	PROSPECT 3 ROUND POND	PROSPECT 4 ISLAND POND	PROSPECT 5 PORTLAND CREEK	PROSPECT 6: EXPLOITS RIVER BADGER CHUTE	PROSPECT 6: EXPLOITS RIVER RED INDIAN FALLS
WATER PROJECTS							
58 The construction, operation, decommissioning and abandonment of a new dam or dyke on a natural water body, if the new dam or dyke would result in the creation of a reservoir with a surface area that would exceed the annual mean surface area of the natural water body by 1 500 ha or more.							
	No. No new dam or dyke.	No. No new dam or dyke.	No. Reservoir size criterion not met. To be confirmed during design.	No. Reservoir size criterion not met. To be confirmed during design.	No. Reservoir size criterion not met. To be confirmed during design.	No. Run-of-river design.	No. Run-of-river design.
59 The expansion of an existing dam or dyke on a natural water body, if the expansion would result in an increase in the surface area of the existing reservoir of 50% or more and an increase of 1 500 ha or more in the annual mean surface area of that reservoir.							
	No. Expansion size criteria not anticipated to be met. To be confirmed during design.	No. Expansion size criteria not anticipated to be met. To be confirmed during design.	No. Not an expansion.	No. Not an expansion.	No. Not an expansion.	No. Not an expansion.	No. Not an expansion.
60 The expansion of an existing structure for the diversion of water from a natural water body into another natural water body, if the expansion would result in an increase in diversion capacity of 50% or more and a total diversion capacity of 10 000 000 m³/year or more.							
	No.	No.	No.	No.	No.	No.	No.
61 The expansion of an existing structure for the diversion of water from a natural water body into another natural water body, if the expansion would result in an increase in diversion capacity of 50% or more and a total diversion capacity of 10 000 000 m³/year or more.							
	No. Expansion size criteria not anticipated to be met. To be confirmed during design.	No. Expansion size criteria not anticipated to be met. To be confirmed during design.	No. Not an expansion.	No. Not an expansion.	No. Not an expansion.	No. Not an expansion.	No. Not an expansion.

4. PERMIT REQUIREMENTS

Federal and provincial permit requirements for the proposed NL Hydro Expansion projects are summarized below. Requirements may vary based on the final configuration of the project to be confirmed during the design phase. Permit requirements are summarized in **TABLE D-3** at the end of this Appendix (starting page D-17).

4.1. FISHERIES ACT (FEDERAL)

The project will require several authorizations under the *Fisheries Act* (R.S.C., 1985, c. F-14), as follows.

- Habitat alteration, disturbance, destruction (HADD) Authorization

  In accordance with the *Authorizations Concerning Fish and Fish Habitat Protection Regulations* (SOR/2019-286), an authorization is Required for activities in or near water containing fish or fish habitat. The proponent must submit details of fish and fish habitat protection / mitigation / compensation or replacement measures.

- Compliance with Fisheries Act section 34(1), “Deleterious Substances”

  Discharge from the project, both during construction and operation, must not be deleterious or lethal to fish. Runoff from site(s) must comply with applicable standards (Canadian Environmental Quality Guidelines). The proponent will need to prepare and submit a Water Sampling and Monitoring Plan, and an Erosion and Sedimentation Control Plan.

One “environmental risk” consideration is noteworthy here. Flooding of reservoirs during development of hydroelectric generating facilities is known to release naturally occurring mercury and arsenic from rock, soil, felled trees and other vegetation exposed to reservoir waters. Concentrations of mercury cannot be predicted in advance. Monitoring of mercury concentrations in the reservoirs and receiving waters will likely be required under both the federal *Fisheries Act* and provincial *Water Resources Act*.

The Exploits River is a scheduled salmon river under the *Fisheries Act*, and this will impact the Exploits River prospects (Badger Chute and Red Indian Falls). Temporary and permanent fish passage structures and scheduling of construction work to avoid impacts to fish during migration periods will likely be included in the terms and conditions of the authorizations for these projects. These measures should be incorporated in the project design and planning process and included in the Fisheries Act authorization documents.

4.2. CERTIFICATE OF APPROVAL FOR ALTERATIONS TO A BODY OF WATER

A Certificate of Approval for Alterations to a Body of Water issued under the *Water Resources Act* (SNL 2002, c. W-4.01, Section 48) will be required for all of the proposed developments, both brownfield and greenfield.

For brownfield developments, the scope of the permit is expected to be limited to construction of the required modifications to the head race (inlet) and tail race (outlet) sections of the existing facilities, including placement of riprap and use of coffer dams. For greenfield developments, the permit will include the overall changes to the water bodies affected by the hydroelectric development. In both cases, NL Hydro standard operating procedures for nearshore construction work, dewatering, erosion and sedimentation control, use of coffer dams and placement of riprap will be submitted with the permit application.

<u>Watercourse Crossing Permits</u>

Watercourse crossing permits issued under the Act will be required for temporary and permanent watercourse crossings (i.e., bridges and culverts).

<u>Certificate of Approval for Instream Activity</u>

A Certificate of Approval issued under the Act is required before construction for instream work (e.g., placement of a coffer dam, channel widening or deepening).

<u>Wetlands</u>

In addition to the Certificate of Approval for Alternations to a Body of Water, the proponent will be required to comply with the "Policy Directive for Development in Wetlands." A permit application will be required under section 48 of the *Water Resources Act* for each affected wetland to be crossed or affected by construction or permanent structures.

Work should be planned and completed to avoid adverse effects to the water quantity, water quality, hydrologic characteristics or functions, and terrestrial and aquatic habitats of the wetlands. Mitigation measures will be required where hydrological functions of wetlands are impacted, however the Newfoundland and Labrador regulations do not include a requirement for compensation or replacement of wetlands.

Two additional considerations should be retained during the project planning phase. First, it is preferable to plan rights-of-way to avoid crossing wetlands where possible. Second, creosote-containing structures in wetlands (including pilings, bridge piers and transmission poles) will not be approved for use in wetlands.

4.3. WATER USE LICENCE

A Water Use Licence issued under section 17 (1) of the *Water Resources Act* (SNL 2002, c. W-4.01) will be required for each project as a whole. NL Hydro and/or Newfoundland Power currently hold individual Water Use Licences for each hydroelectric facility in their portfolios.

For greenfield developments, a new Water Use Licence is required to enable water withdrawal and transfer from a headpond / reservoir to downstream receiving waters. For brownfield developments, the existing Water Use Licences will need to be amended to account for changes in flow rates or volumes associated with the planned additional turbines.

If groundwater wells are needed to supply employee facilities at the dam or powerhouse locations, these will need to be included in the Water Use Licence.

Additional Water Use Licences may be required for process / makeup water used during construction, for example in concrete mixtures or for dust control on roads.

<u>Environmental Control Water and Sewage Regulations (2003)</u>

Hydroelectric dam effluent discharged into receiving waters must comply with the *Environmental Control Water and Sewage Regulations*, generally included in the terms and conditions of the Water Use Licence.

As stated in the summary of requirements under the federal Fisheries Act, elevated mercury concentrations are a known consequence of hydroelectric dam development. This may constitute "Release of a Substance" as considered by the provincial *Environmental Protection Act*. Monitoring of mercury concentrations in the reservoirs and receiving waters will likely be required under both the federal and provincial regulations.

4.4. WASTE MANAGEMENT

Preparation of a soil management plan in accordance with the "Guidance Document – Protocol for the Management of Excavated Soils, Concrete Rubble and Dredged Materials" (GD-PPD-054.2, 2005 rev. 2015) is anticipated to be a requirement of environmental approvals for these projects. In addition, petroleum impacted soil generated during construction, if any, must be transported to an existing licenced facility.

A Waste Certificate of Approval issued under section 16 of the *Environmental Protection Act* will not be required for the proposed hydroelectric generation expansion projects, as NL Hydro is not anticipated to operate a stand-alone facility as part of these projects.

4.5. WILDERNESS AND ECOLOGICAL RESERVES REGULATIONS

Based on a preliminary review, none of the proposed hydroelectric developments are located within a designated provincial wilderness and ecological reserve as defined by the *Wilderness and Ecological Reserves Act* (RSNL 1990, c. W-9).

However, if subsequent review determines that portions of the infrastructure associated with the proposed projects (e.g., roads or transmission lines, or reservoir boundaries) will pass through or contact a wilderness or ecological reserve, certain provisions under clause 23. (1) of the Wilderness Reserve Regulations, 1997 (NLR 65/97) will apply. These include submission of an environmental protection plan detailing how work will be carried out to minimize environmental damage and submission of annual work plans detailing the type and timing of work to be carried out.

4.6. SPECIES AT RISK ACT AND MIGRATORY BIRDS CONVENTION (FEDERAL)

Evaluation of potential presence of species at risk listed under the *Species at Risk Act* (S.C. 2002, c. 29) and the *Migratory Birds Convention Act, 1994* (S.C. 1994, c. 22) will need to be conducted for the prospects.

For brownfield developments, this will be a desktop review of available species population and habitat data. For greenfield developments, this will include both a desktop review and field surveys. A permit or agreement under section 73(1) of the *Species at Risk Act* may be required if project activities affect a listed wildlife species, any part of its critical habitat or the residences of individuals.

The *Migratory Birds Convention Act* applies to activities that could cause disturbance to or mortality of federally listed migratory birds. The Act also applies to discharge of harmful substances in waters or areas frequented by migratory birds. Compliance requirements are anticipated to be similar to the *Fisheries Act* "Deleterious Substances" requirements.

The proponent will need to submit plans to avoid disturbance or destruction of nests and eggs through timing of work or design considerations / mitigation measures in the project EA registration and permit applications.

4.7. CANADIAN NAVIGABLE WATERS ACT (FEDERAL)

Some of the watercourses under consideration for development under the NL Hydro Generation Expansion projects may be designated as "navigable waters" under the *Canadian Navigable Waters Act* (R.S.C. 1985, c. N-22). This includes use of rivers for recreational boating.

Permits under the *Navigable Waters Works Regulations* (C.R.C., c. 1232) will be required for activities in or across navigable water as defined by the Act, including works located below the high-water mark, or works passing over, under or through navigable waters. In addition, publication of notifications in accordance with the *Minor Works Order* (SOR/ 2021-170) will be required for erosion protection works, aerial cables, submarine cables, buried pipelines, outfalls and water intakes, dredging and watercourse crossings.

4.8. ADDITIONAL PERMITS AND LICENCES – OPERATIONAL PHASE

Additional permits will be required for the operational phase of the project for items such as auxiliary generators required to operate dam lift gates or other infrastructure in the event of power failures; associated fuel storage tanks; and onsite new and used lubricant storage. These permits can be obtained after the primary EA approval and construction permits have been obtained. Applicable regulations for issuance of these permits include:

- Air Pollution Control Regulations, 2004;
- Storage and Handling of Gasoline and Associated Products Regulations, 2003;
- Used Oil Control Regulations.

NL Hydro (Licence no. 14-043) is currently a Licenced Pesticide Operator for industrial vegetation control under the *Environmental Protection Act* (SNL 2002, c. E-14.2) and the *Pesticides Control Regulations, 2012*. In addition, NL Hydro currently holds two Water Use Licences (WUL-22-12516 and WUL-21-11929) for withdrawal and use of water from water bodies along its transmission line rights-of-way for vegetation management. It is the anticipated that vegetation control for the proposed hydroelectric generation expansion projects will be covered under the existing licences or their renewals.

5. SOCIOECONOMIC INFLUENCES

Socioeconomic considerations must be documented fully in whatever form of EA process is followed for the NL Hydro Generation Projects (i.e., EPR, EIS, Robust Registration or Class EA). These are anticipated to include, at a minimum:

- Anticipated labour requirements during the construction and operational phases of the project;
- Economic impacts of the project (consumer electricity rates, wages, government revenue and taxation, indirect impacts to the local and regional economy);
- Local, regional and national labour market impacts, including availability and skills development for trained positions and labour equity considerations;
- Safety and security considerations related to extra-regional transient labour during construction, if planned;
- Aboriginal stakeholder engagement.

Aboriginal stakeholders must be engaged early in the planning process. Aboriginal traditional ecological knowledge, historical and current land use, and ceremonial uses of the land and resources must be considered throughout the planning and development process. Opportunities for direct Aboriginal participation in construction and operation of the project through training and employment should be identified.

6. TIMELINES

The anticipated timelines for completion of the EA and permitting process will vary by project. Based on experience with projects of a similar nature, the following timelines are anticipated:

Brownfield (Bay d'Espoir Unit 8, Cat Arm Unit 3)

Approximately 6 months from registration to EA release under the provincial *Environmental Assessment Regulations*, based on:

- Primarily a permit application process. Timelines for issuance of permits varies and is not specified in the relevant regulations;
- Desktop study to document environmental impacts (no field studies required);
- Application of standard operating procedures and mitigation measures;
- Limited federal government involvement (no migratory fish impacts, limited potential impacts to fish or fish habitat);
- Limited public comment on environmental registration document, once published in the provincial EA register;
- Release from further EA anticipated without further documentation.

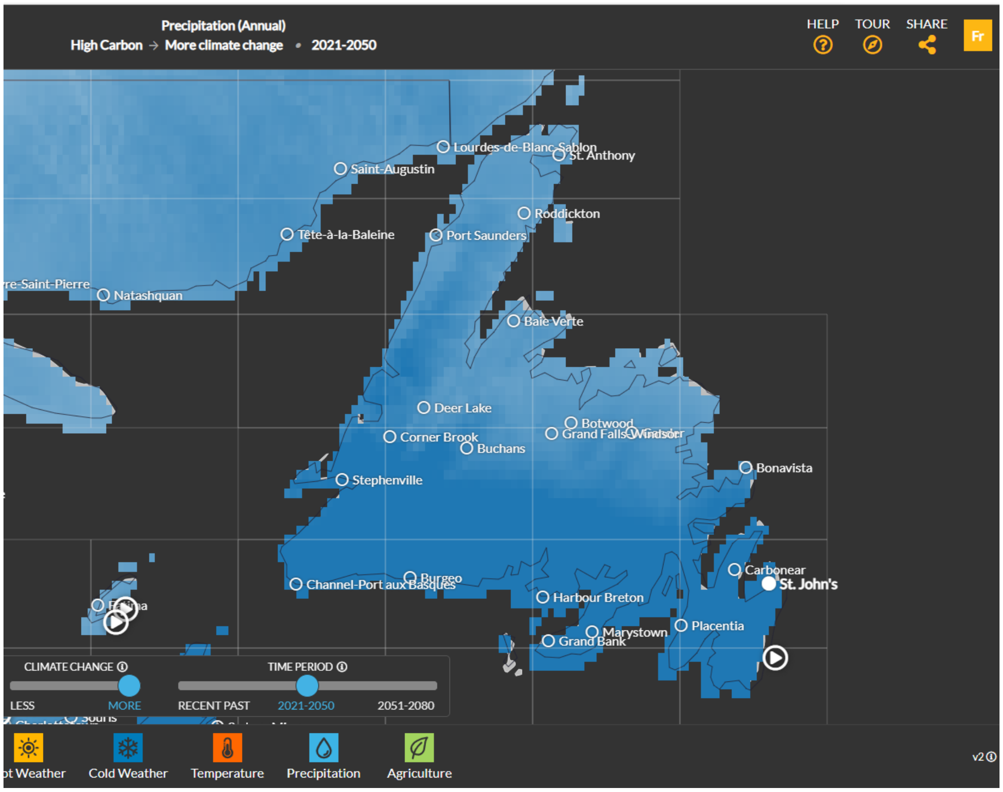
Greenfield

Approximately 2.5 years from registration for EA approval under the Environmental Assessment Regulations, based on:

- Ecological field studies required (fish presence and habitat surveys, avian, terrestrial wildlife and species at risk surveys);
- Field studies must be planned in the autumn of the prior year to start late March/early April of the following year, and continue for 12 consecutive months;
- Field studies to be completed in advance to support submission of a robust EA registration document;
- Application of standard operating procedures and mitigation measures;
- Federal Fisheries Act authorizations (HADD and others) will be required. Timelines for authorizations are not specified in the regulations; anticipate 2.5 years, coincident with provincial EA process;
- Level of public engagement cannot be predicted in advance; may extend approval process by 1 year;
- Release from further EA is feasible with submission of a robust registration document that fulfils all content requirements.

7. CLIMATE CHANGE

The potential implications of climate change were not addressed in this study. However, information from the Climate Atlas of Canada is provided in **FIGURE D.1** below for Hydro's consideration.



Changes in comparison with 1976-2005 (référence period)										
	Annual Precipitation (mm)					Annual Mean Temperature (°C)				
Climate Change	*Base*	*Less*		*More*		*Base*	*Less*		*More*	
	1976-2005	2021-50	2051-80	2021-50	2051-80	*1976-2005*	2021-50	2051-80	2021-50	2051-80
Blanc -Sablon	1042	+7%	+10%	+8%	+13%	*0.9*	2.5	3.5	2.8	4.9
St-Anthony	1022	+6%	+9%	+7%	+12%	*1.3*	2.8	3.7	3.1	5.0
Port Saunders	1062	+7%	+10%	+8%	+13%	*2.2*	3.8	4.8	4.1	6.1
Bay of Island	1169	+6%	+9%	+7%	+12%	*3.9*	5.6	6.6	5.9	7.9
Sandy Lake	1073	+6%	+9%	+7%	+13%	*3.1*	4.8	5.7	5.0	7.0
Botwood	1040	+6%	+8%	+7%	+12%	*4.4*	5.9	6.8	6.1	8.0
Stephenville	1274	+6%	+8%	+6%	+11%	*3.9*	5.6	6.6	5.8	7.9
Red Indian Lake	1243	+6%	+8%	+7%	+12%	*3.4*	5.1	6.0	5.3	7.2
Gander Lake	1176	+6%	+8%	+6%	+11%	*4.5*	6.1	6.9	6.3	8.2
Bonavista	1166	+5%	+7%	+6%	+10%	*5.1*	6.5	7.3	6.7	8.5
Port-aux Basques	1408	+5%	+8%	+6%	+11%	*4.0*	5.7	6.6	5.8	7.9
Burgeo	1430	+6%	+8%	+6%	+11%	*4.2*	5.8	6.7	6.0	7.9
Belleoram	1352	+6%	+8%	+6%	+10%	*5.0*	6.5	7.4	6.7	8.6
St. John's	1341	+5%	+7%	+5%	+9%	*5.3*	6.7	7.5	6.8	8.6
St Lawrence	1402	+5%	+7%	+5%	+9%	*5.3*	6.8	7.6	6.9	8.8
Trepassey	1439	+5%	+7%	+5%	+8%	*5.1*	6.5	7.3	6.6	8.4
Average		***+5.8%***	***+8.2%***	***+6.4%***	***+11.1%***	***3.9***	***5.4***	***6.3***	***5.6***	***7.6***

FIGURE D.1 FORECASTED PRECIPITATION CHANGES (source: Climate Atlas of Canada)

TABLE D-3 APPLICABLE STATUTES AND REGULATIONS

PART 1 OF 4: PROVINCIAL STATUTES AND REGULATIONS			
Statute / Regulation	**Responsible Department**	**Permit / Approval**	**Details**
Environmental Protection Act (SNL 2002, c. E-14.2) Environmental Assessment Regulations, 2003 (NLR 54/03)	Dept. of Environment and Climate Change- EA Division	EA Registration (proponent submittal) EA Release (ministerial approval)	Environmental Assessment Registration and Release are required for each project as a whole. Multiple triggers for Registration under Section 34(1), Section 34(2) for power lines and 35(1) for associated roads. Considerations: Robust registration document may streamline approval – see text. Class EA for hydroelectric developments may accelerate approval of future projects.
Environmental Protection Act (SNL 2002, c. E-14.2) Guidance Document GD-PPD-054.2 (2005, rev. 2015)	Dept. of Environment and Climate Change	Compliance Approved Soil Management Plan	Comply with Guidance Document – Protocol for the Management of Excavated Soils, Concrete Rubble and Dredged Materials.
Water Resources Act (SNL 2002, c. W-4.01)	Dept. of Environment and Climate Change-Water Resources Division	Certificate of Approval for Alteration to a Body of Water	Required for construction within 15 m of high-water mark (e.g., placement of riprap, berms, lateral roads). Separate permit application required for each alteration.
Water Resources Act (SNL 2002, c. W-4.01)	Dept. of Environment and Climate Change-Water Resources Division	Permit for Development in Wetlands under Section 48 of the Act	Required for each affected wetland to be crossed or affected by construction or permanent structures Design considerations: Plan rights-of-way to avoid crossing wetlands where possible. Creosote-containing structures will not be approved.

PART 1 OF 4: PROVINCIAL STATUTES AND REGULATIONS			
Statute / Regulation	**Responsible Department**	**Permit / Approval**	**Details**
Water Resources Act (SNL 2002, c. W-4.01)	Dept. of Environment and Climate Change- Water Resources Division	Watercourse Crossing Permits	Required for temporary and permanent watercourse crossings (bridges, culverts)
Water Resources Act (SNL 2002, c. W-4.01)	Dept. of Environment and Climate Change- Water Resources Division	Certificate of Approval for Instream Activity	Required before construction for instream work (e.g., coffer dam, channel widening or deepening)
Water Resources Act (SNL 2002, c. W-4.01)	Dept. of Environment and Climate Change- Water Resources Division	Water Use Licence issued under Section 17 (1) for hydroelectric use Additional licences (see Details column)	Required for each project as a whole. A new Water Use Licence is required to enable water withdrawal and transfer from a headpond / reservoir to downstream receiving waters. Existing licences for Bay d'Espoir and Cat Arm may need to be amended for changes in flow rate or volume. Additional licence may be required for an onsite potable water source (either intake from the reservoir or well). Additional licence may also be required for process / makeup water during construction (e.g., for use in concrete, dust control on roads, etc.).
Water Resources Act (SNL 2002, c. W-4.01)	Dept. of Environment and Climate Change- Water Resources Division	Certificate of Approval for Construction Site Drainage	Required for site runoff. Runoff drainage plans to be submitted with overall application.

PART 1 OF 4: PROVINCIAL STATUTES AND REGULATIONS			
Statute / Regulation	**Responsible Department**	**Permit / Approval**	**Details**
Water Resources Act (SNL 2002, c. W-4.01) Environmental Control Water and Sewage Regulation	Dept. of Environment and Climate Change-Water Resources Division	Compliance / permit	Required for water or sewage discharges from the project. Effluent must comply with standards in the regulations
Water Resources Act (SNL 2002, c. W-4.01) Water Power Rental Regulations, 2003 (NLR 64/03)	Dept. of Environment and Climate Change-Water Resources Division	fee payment	Not required for construction -- applicable during operational phase only.

PART 2 OF 4: FEDERAL STATUTES AND REGULATIONS

Statute / Regulation	Responsible Department	Permit / Approval	Details
Impact Assessment Act (S.C. 2019, c. 28, s. 1)	Environment Canada	EIA Approval	No federal EIA triggers for currently planned hydro expansion projects (except Cat Arm: see accompanying text).
Fisheries Act (R.S.C., 1985, c. F-14) Authorizations Concerning Fish and Fish Habitat Protection Regulations (SOR/2019-286)	Fisheries and Oceans Canada	Habitat alteration, disturbance, destruction (HADD) Authorization	Required for activities in or near water containing fish or fish habitat. Proponent must submit details of fish and fish habitat protection / mitigation / compensation or replacement measures.
Fisheries Act (R.S.C., 1985, c. F-14) Section 34(1): “Deleterious Substances”	Environment Canada (Section 36(3) of Fisheries Act) Fisheries and Oceans Canada (sedimentation)	Compliance	Discharge must not be deleterious or lethal to fish. Runoff from site(s) must comply with applicable standards (Canadian Environmental Quality Guidelines) Proponent will need to prepare and submit a Water Sampling and Monitoring Plan, and an Erosion and Sedimentation Control Plan.
Canadian Navigable Waters Act (R.S.C., 1985, c. N-22) Navigable Waters Works Regulations (C.R.C., c. 1232)	Transport Canada	Permit(s)	Required for activities in or across navigable water as defined by the Act. Not applicable for all planned projects – applicability to be determined on a case-by-case basis during project planning. Permits may be required for works located below the high-water mark, over/under/through navigable waters.
Canadian Navigable Waters Act (R.S.C., 1985, c. N-22) Minor Works Order (SOR/ 2021-170)	Transport Canada / Canadian Coast Guard	Notification of a Minor Work	Applicability to be confirmed during project planning. Applies to erosion protection works, aerial cables, submarine cables, buried pipelines, outfalls and water intakes, dredging and watercourse crossings.

PART 2 OF 4: FEDERAL STATUTES AND REGULATIONS			
Statute / Regulation	**Responsible Department**	**Permit / Approval**	**Details**
Species at Risk Act (S.C. 2002, c. 29)	Canadian Wildlife Service, Environment Canada	Permit or Agreement under Section 73(1) of the Act	May be required if project activities affect a listed wildlife species, any part of its critical habitat or the residences of individuals.
Migratory Birds Convention Act, 1994 (S.C. 1994, c. 22) Migratory Birds Regulations (C.R.C., c. 1035)	Canadian Wildlife Service, Environment Canada	Permit	Applies to activities that could cause disturbance to or mortality of federally listed migratory birds. Also applies to discharge of harmful substances in waters or areas frequented by migratory birds. Compliance requirements similar to Fisheries Act “Deleterious Substances” requirements. Submit plans to avoid disturbance or destruction of nests and eggs through timing of work or design considerations / mitigation measures.

PART 3 OF 4: MUNICIPAL STATUES AND REGULATIONS			
Statute / Regulation	**Responsible Department**	**Permit / Approval**	**Details**
Urban and Rural Planning Act Municipal Planning Regulations	Municipal Planning Dept.	Development or Building Permit	Building permits required within municipal boundaries
Urban and Rural Planning Act Municipal Planning Regulations	Municipal Dept of Public Works or Landfill Operator	Waste disposal approval	Approval required for waste disposal by contractors

PART 4 OF 4: CODE COMPLIANCE (BUILDINGS / FIRE/ OH&S)

Statute / Regulation	Department	Permit / Approval	Details
National Building Code	Service NL	compliance / permit	Required for all onsite structures (during construction and permanent occupancy) Prepare and submit building plans
National Fire Code	Service NL	compliance / permit	Required for all onsite structures (during construction and permanent occupancy)
NL Fire Prevention Act and Regulations	Service NL	compliance / permit	Required for all onsite structures (during construction and permanent occupancy)
NL Occupational Health and Safety Act and Regulations	Service NL (Dept. of Labour)	compliance / permit	Proponent must prepare HASP (for construction and for facility operation) Notify Dept. prior to construction
Occupational Health and Safety Act WHMIS Regulations	Service NL (Dept. of Labour)	-	Proponent must prepare and submit a project specific WHMIS document detailing HazMat's in use on site, incl. handling, storage and labelling instructions

Newfoundland and Labrador Hydro
Combustion Turbine Screening

Final Study Report

Date	Rev.	Status	Prepared By	Checked By	Approved By
2022-10-28	1	Final	O. Owolabi	K. Meghari	K. Meghari
2022-10-17	0	Final	O. Owolabi	K. Meghari	K. Meghari
HATCH					

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Acronyms

BXX	Blended XX percent biodiesel with (1-XX) ULSD
CCS	Carbon Capture and Storage
CRFP	Carbon Fibre Reinforce Polymer
CFS	Clean Fuel Standard
CH2	Compressed Hydrogen Gas
CI	Carbon Intensity
FAME	Fatty Acid Methyl Esters
GE	General Electric
GHG	Greenhouse Gas
GTG	Gas Turbine Generator
HDRD	Hydrogenation Derived Renewable Diesel
LH2	Liquid Hydrogen
MCC	Motor Control Centre
MHI	Mitsubishi Power Aero
NL	Newfoundland and Labrador
NLH	Newfoundland and Labrador Hydro
OEM	Original Equipment Manufacturer
PFD	Process Flow Diagram
RFRs	Renewable Fuels Regulations
SMR	Steam-methane reforming
TIC	Total Installed Cost
ULSD	Ultra-Low Sulphur Diesel, conventional diesel, fossil diesel

1. Executive Summary

Newfoundland and Labrador Hydro (NLH) as part of its system planning strategy is investigating efficient, reliable, and cost reflective combustion turbine technology options that will meet the growing power demand of the province.

Hatch was engaged by NLH to carry out a combustion turbine screening study aimed at reviewing industrial gas turbines with fuel flexibility, fast start, and synchronous condenser capability. The simple cycle combustion turbine will be designed to operate at base load, part load and peaking load to accommodate the varying power demand profile of the province.

The objective of the study consists of:

- Performing a conceptual study including a preliminary process flow diagram, combustion turbine performance estimate, plant layout, site assessment, level 1 project schedule, and a class 5 cost estimate.
- Reviewing the use and sourcing of biodiesel, ethanol, and hydrogen within the provinces to generate electricity.

Two base scenarios were considered in the study, these are:

- **Scenario 1:** Two (2) units to achieve 100 MW nominal simple cycle power plant.
- **Scenario 2:** Four (4) units to achieve 200 MW nominal simple cycle power plant.

1.1 Site Location

The study categorises the sites into two broad groups, namely a greenfield and brownfield site location. The greenfield location is an undeveloped land with little to no existing shared facility, while brownfield site locations have shared facilities that can be leveraged in the design of the proposed power plant. One major advantage of using a brownfield site is the exclusion of capital cost such as land acquisition from the project developmental cost. Holyrood thermal generating station was identified as a proposed brownfield site. Both greenfield and brownfield site are identified along the Avalon Peninsula in Newfoundland and Labrador.

1.2 Combustion Turbine

Three major original equipment manufacturers (OEM) were contacted, which were selected due to the nominal power requirement for the plant. The three OEMs are General Electric (GE), Siemens, and Mitsubishi Power Aero (MHI). A gas turbine specification sheet was developed and shared with the OEM to obtain a budgetary price, equipment general arrangement, fuel capability, estimated major equipment delivery date, turbine experience on biofuels and hydrogen, and estimated performance. The OEMs responded to the specification sheet by proposing units that closely match the defined requirements. The proposed units are:

- GE – LM6000 PC Sprint.
- Siemens – SGT 800.

- MHI – FT4000.

1.2.1 Fuel Capability

GE with the LM6000 aeroderivative gas turbine has limited experience burning ethanol or biodiesel. The unit is designed to burn a maximum of 35% hydrogen by volume, however some balance of plant upgrade would be required.

Siemens has limited experience with biodiesel but confirms its capability. The SGT800 is currently being built in Sweden to run on biodiesel with a commercial operation date of 2023. As of the time of the report, Siemens do not have any experience burning ethanol in their gas turbine fleet. However, they claim they have the technology and are willing to partner with any developer or utility power producer to achieve this capability. The SGT800 can burn 75% hydrogen at the time of this report.

The FT4000 is designed to run on liquid fuel such as diesel and natural gas. As of the time of this report, the FT4000 does not have the capability to burn any biofuel, and its capability to burn hydrogen has not been verified.

1.2.2 Project Schedule

A level 1 preliminary project schedule was developed for two (2) and four (4) unit gas turbines. The estimated timeline for budgeting approval, environmental assessment, engineering procurement, construction, and management to commercial operating is approximately 3 and 4 years for the two- and four-unit configuration respectively. This time is highly dependent on gas turbine generator availability from OEM.

1.2.3 Capital Cost

The capital cost of each scenario is broken down into direct cost, indirect cost, and contingency. The equipment list with budgetary numbers received from OEM’s was used to develop an AACE Class 5 Estimate with target accuracy of -20% to + 30%.

The capital cost estimate was compiled based on the following parameters:

- General Electric - LM6000 PC Sprint budgetary price.
- The Hatch Thermal Power Plant Factored Estimate model was used develop the costs by area and system. The Hatch Thermal Factored Model was developed from benchmark data for completed projects and definitive estimates.

The average labour rate for all works was established by Hatch.

GE – LM6000 PC Sprint was used in developing the cost estimate as it meets the technical requirement as specified in the specification sheet. Siemens SGT 800 was also reviewed; however, the unit has not demonstrated experience burning ethanol and has a longer start up time. As for the MHI FT4000, while the unit is designed to burn diesel, natural gas, and hydrogen blend, it has no capability and experience in burning biofuels.

A summary of the capital cost estimate is shown in Table 1-1.

Table 1-1: Capital Cost

Breakdown of Activities	Greenfield		Brownfield	
	2 x 50 MW	4 x 50 MW	2 x 50 MW	4 x 50 MW
Direct cost	$159,217,000	$276,356,000	$150,523,000	$267,174,000
Indirect cost	$31,259,000	$48,854,000	$30,879,000	$47,533,000
Contingency	$36,503,000	$62,278,000	$34,775,000	$60,270,000
Capital Costs	$226,979,000	$387,488,000	$216,177,000	$374,977,000

1.3 Biofuel Sourcing

There is currently no established biofuel supply chain in Newfoundland and Labrador (NL). The Braya Renewable Fuels production facility in Come by Chance is the only biofuel producer in NL, and they are not expected to be supplying into Canada in the near future as they are selling into more established markets in the US. Biofuel is currently being produced in other provinces such as Ontario and Quebec, but the majority of these are either being used in-province or exported to the US. Several announcements regarding biofuel production projects in Canada have been made, but none of them are set to be in NL.

Pure biodiesel and renewable diesel costs in Canada are currently 1.5 to 2 times higher than petroleum diesel. Ethanol (E85) has always been $0.2-0.3 cheaper than gasoline per gallon, but more expensive on an energy equivalent basis. This cost difference is primarily due to the high production and supply cost, in addition to the lack of low-carbon fuel incentives and policies in place.

Storage for biofuels also requires additional considerations as it may differ from their petroleum counterparts. Pure Biodiesel (B100) needs to be stored in insulated and heated tanks during winter months as it is sensitive to cold temperatures. Long-term storage of biodiesel may cause complications due to different summer and winter blends, degradation caused by temperature fluctuations, and exposure to oxygen. Unlike biodiesel, renewable diesel does not have cold temperature concerns and is more stable for long-term storage. Ethanol is biodegradable and does not have the toxic or carcinogenic properties of gasoline. However, if blended, the harmful properties of gasoline will still apply to the ethanol blend.

1.4 Hydrogen Sourcing

There is currently no established hydrogen supply chain in NL. The refinery located in Come by Chance is the sole user of hydrogen on the island, which is produced and consumed onsite. The hydrogen is produced from butane feedstock, which is imported to the facility, and would be considered grey hydrogen. This is not a clean form of hydrogen production and is not an option to reduce emissions in power generation using hydrogen. Cleaner hydrogen production technologies, such as green hydrogen (via electrolysis) or blue hydrogen (steam-methane reforming with carbon capture), should be considered for emissions reduction.

NL's proximity to natural gas reservoirs (for blue or grey hydrogen production) along with its renewable energy sources in hydropower and wind (green hydrogen production), shows the large potential for hydrogen production in the province. However, the province is not currently projected to have a large domestic demand and most of the production being considered is dedicated to export markets.

Several hydrogen production projects have recently been announced in NL and other parts of Eastern Canada. Many of these projects are still in the early stages of development. This report has identified some of the key projects in the area. There may be potential to partner with some of these projects to import hydrogen for power generation.

Green hydrogen production via electrolysis is very energy-intensive and capital-intensive. High-level CAPEX and OPEX estimates have been produced for a nominal 200 MW facility (producing approximately 100 tonnes of hydrogen per day), to provide an order-of-magnitude indication for the level of investment required to produce green hydrogen.

A summary of the cost estimate is shown in Table 1-1.

Table 1-2: Hydrogen Capex Cost

Budgetary CAPEX	Alkaline, MM CAD	PEM, MM CAD
Direct Cost	**235 – 335**	**310 – 415**
Utilities	30	35
Indirect Cost @ 33.5%	90	115
TIC Total (US Gulf Coast Cost)	**355 – 455**	**460 – 565**
TIC Total (NL Cost @ 1.2 factor)	**425-545**	**550 – 680**

2. Introduction

Newfoundland and Labrador Hydro has engaged Hatch to carry out a combustion turbine screening study. The combustion turbine screening study stems of Newfoundland and Labrador Hydro's system planning strategy to continuously improve its generation capacity to meet power demands and reliability.

The study examines potential location of the powerplant on a greenfield and brownfield site. The greenfield sites are located on the Avalon Peninsula, situated on the southeastern part of the island of Newfoundland, while the brownfield site is located at Holyrood thermal power plant.

In addition to examining different potential site locations, the study included different power output scenarios. These scenarios are:

- **Scenario 1:** Two (2) units to achieve 100 MW nominal simple cycle power plant.
- **Scenario 2**: Four (4) units to achieve 200 MW nominal simple cycle power plant.

The combustion turbine was screened based on the equipment fast start capability, synchronous condenser, fuel flexibility and ability to be used as a back up generation and peaking plant. An AACE class V estimate was developed for the two scenarios for the greenfield and brownfield sites.

Technical limitations of burning hydrogen, diesel, biofuels such as ethanol and biodiesel in the combustion turbine was reviewed along aside specific upgrades required for a turbine to burn more volume of hydrogen and biofuels.

Furthermore, as part of the scope of this study, the sourcing and transportation of hydrogen, biodiesel, and ethanol within and outside the province was reviewed, and considered hydrogen storage requirements and production.

3. Design Criteria

3.1 General Plant Description

3.1.1 Plant Description and Configuration

The combustion turbine generators will be arranged in a parallel configuration with sufficient spacing for equipment maintenance, including crane access and laydown. Each combustion turbine generator (CTG) will be a stand-alone generating unit which will include all necessary support equipment including exhaust stack, air cooled lube oil coolers, power augmentation and winterization packages. A diesel generator will be required to initiate startup sequence of the combustion turbine generator in the absence of an external power source.

Each generator is connected to the switchyard through a dedicated step up transformer located to the north of each generator.

The CTG package and plant auxiliary systems include the following:

- Fuel system including filtration.
- Compressed air for the self-cleaning CTG inlet air filters and other service and instrument air users.
- Demineralized water for emission control and power augmentation.
- Water wash skid and Aerosol fire protection system.
- Balance of plant control and electrical system.
- Turbine exhaust system with exhaust silencers, expansion joints, ducts, and instrumentation.

3.1.2 Operating Requirements

The CTG will be designed for cyclic, peak, part, and base load service. Each unit will be capable of frequent start-ups and shutdowns as well as occasional full load rejection trips and shall be designed suitable in all respects for cycling service operation. Although the turbine is capable of frequent cycling the initial planned service is defined as follows:

- CTG starts/year: 120
- Maximum operating hours/year: 8,000
- Normal operating hours/year: 500

3.1.3 Redundancy Design Philosophy

Plant redundancy will be provided as follows:

- Each CTG system will be complete and capable of full load operation without support from the other units. Full system and component redundancy is not provided within a single CTG package. However, redundancy is provided within the CTG package for protection and control and as required to prevent equipment damage. Backup power during a turbine trip is provided by a battery powered DC system. This will power the emergency lube oil pumps for safe shut down process of the equipment. This will prevent thermal stress on the gas turbine rotor and bearings due to abrupt stoppage of the unit.
- Redundancy will be provided for all normally operating fuel system components, i.e., pressure regulating valves and filter/separators.
- Service and demineralization water pumps with independent power supplies will be provided with 100% redundancy in pump capacity.
- Redundant air compressors and air dryers with independent power supplies will be provided.

4. Design Basis

4.1 Electrical, Instrumentation and Control System

The power plant electrical system is designed to include a high and low voltage system, generator step-up transformers, lighting poles/panels, cathodic protection for outside tanks, and exhaust stack lightning protection.

The electrical, instrumentation, and control system for the combustion turbine includes the following:

- Air-conditioned control room for turbine/generator panels.
- Electric motor driven hydraulic pump assembly.
- 600 VAC electrical power for gas turbine starting and accessories.
- Electrical power connections (power cable or duct) from the generator lineside cubicle to the plant facility electrical systems.
- Electrical control connection from the on-base terminal points to the turbine control panel, and from the generator control panel to plant facility electrical systems.
- Motor control centers (MCC) and auxiliary power transformers.
- Control cables between the turbine/generator panels and MCC.
- Power cables to and from the 24/125 VDC battery and charger systems.
- Generator protective relay panels.
- Automatic voltage regulator, power system stabilizer and vibration monitor.

4.2 Civil and Structural

The structural design at all sites is based on a simple steel-frame building with concrete foundations and metal cladded exterior. Depending on the interior layout requirements, this can be accomplished using a stick-build or pre-engineered type of construction.

It is anticipated that the geotechnical conditions on site will allow for the foundations to be a spread footing type bearing on undisturbed native fill or bedrock without the need for a piled foundation. The foundations are expected to have an underside of footing that is below frost depth, which is assumed to be 1.5 metres below finished grade. The slab-on-grade will be designed to support standard occupancy load and any additional equipment may have either a thickened slab or separate foundation detail, depending on specific equipment isolation and loading requirements.

The environmental loading for the building (wind, snow, and seismic) will be based on the NBCC 2015 for St. John’s, NL since all sites are near the city. The structure is anticipated to be a “normal” importance category for all environmental loads.

Other than the excavation and backfill requirements for installation of the foundations, it is assumed that none of the proposed sites require a significant amount of site grading or drainage detailing.

Overhead cranes will be installed in the powerhouse to facilitate major maintenance.

4.2.1 Heating, Ventilation, and Air Conditioning (HVAC)

The ventilation system for the turbine building will provide sufficient air circulation to ensure that heat losses from the equipment do not result in an excessive and/or uneven temperature distribution. It also will maintain acceptable working conditions within buildings and structures.

The air intake and exhaust stack of the combustion turbine will be located just outside the powerhouse building allowing sufficient access for maintenance activities.

The air conditioning system will maintain comfortable working conditions in the control room, and electrical room. It will also maintain the required humidity and temperature levels in control rooms and some equipment rooms as applicable.

The system will be designed to the latest revision of the NBC and applicable ASHRAE and ASTM standards.

4.3 Mechanical

4.3.1 Fuel Type

The basis for the design of the simple cycle aero derivative combustion turbine is that the turbines need to have the capability of running on diesel with a possibility of converting to either biodiesel, ethanol, or hydrogen in the future.

The liquid fuel system includes the following major components:

- Manual isolation valve.
- Fuel offloading and forwarding pumps.
- Electric fuel heaters.
- Coalescing filter.
- Fire safety valve with limit switches.
- Duplex filter assembly.
- Fuel boost pump.
- Metering flow control valve.
- Automatic shut-off valves.
- Flow meter.
- Flow divider valve.

- Automatic drain valves.
- Pressure and temperature instrumentation.

4.3.1.1 *Fuel Storage*

The tank farm is designed for continuous diesel fuel supply for seven (7) days at the maximum rated capacity of the gas turbine (GT). The tank farm also include fuel forwarding and offloading pumps.

Table 4-1: Fuel Storage

Combustion Turbine	Number of Tanks	Tank Volume
2 Units	2	1400 m^3
4 Units	2	2800 m^3

4.3.2 *Combustion Turbine Generators*

The combustion turbine generators will operate in simple cycle mode with an aeroderivative technology and have a nominal capacity of 50 MW. The generators need to have synchronous condensing capabilities as well as fast start capabilities up to the rated load in 10 minutes or less.

4.3.2.1 *Combustor Technology*

Combustion turbine generator is designed with either a single annular combustor (SAC) or dry low emission (DLE) combustor. In a single annular combustor, combustion is achieved with a diffusion flame technology where compressed air and fuel are separated before burning in the combustion chamber. This results in high flame temperatures, hence high NOx. SAC technology requires water injection for NOx abatement.

Dry low emission combustor used premix flame approach to achieve combustion. The fuel and compressed air are premixed before being injected in the combustion chamber of the gas turbine. This allows for better control of the combustion process, hereby reducing NOx formation without water injection.

DLE is a modification of the SAC combustors but is limited in application to type of fuel. For nonconventional fuels like biodiesel, ethanol, or naphtha, a single annual combustor is preferred for its robustness and hence requiring water injection for control NOx.

4.3.3 *Raw Water*

For the greenfield sites, raw water can potentially be supplied from municipalities water main, which can be piped to site. While for the brownfield site, we have assumed the existing Holyrood Power Plant raw water system can provide raw water to the combustion turbines.

4.3.4 *Demineralized Water*

Demineralized water will be used for the following:

- The Sprint power augmentation system at a maximum flow rate as specified in GE Contract.
- Compressor water wash.

- NOx abatement.

A demineralization plant will be built to supply demineralized water for plant use. Service water will be demineralized then pumped and stored in the demineralized water tank.

Demineralized water will be pumped from the demineralized water tank to the combustion turbine Sprint skids.

The demineralized water system will be designed to meet the water quality requirements.

The demineralized water system includes the following:

- Multimedia Inlet Filter
- Reverse Osmosis System
- Polishing demineralizer
- Demineralized water tank:
  - Demineralized Water Pumps: 2 x 100%

The demineralized tank construction will be stainless steel with interior coating.

The demineralized water tank will be provided with insulation and immersion heaters to prevent freezing.

The plant demineralized water pumps and service water pumps will be in a building.

4.3.5 Compressed Air

The compressed air will provide for both “Instrument Air” and “Service Air” from common compressors. Both instrument and service air will be dried before distribution to prevent freezing/corrosion.

Compressed air will be used for the following:

- CTG inlet air self-cleaning filter (air pulse type).
- CTG lube oil shut down cooling.
- Miscellaneous Instrument Air Users.
- Miscellaneous Service Air Users.

The following equipment will be included:

- Compressors.
- Air dryers.
- Receivers.

The air receiver will be sized to provide emergency shutdown of the power plant when all power to compressors has been lost.

4.3.6 Glycol Cooling System

The Glycol Cooling System for the main lube oil system consists of a fin fan air cooled heat exchanger and a single glycol circulation pump with a three-way temperature control valve. The glycol cooler is located outdoors, and the circulating pump and three-way temperature control valve are in the Auxiliary Module Building dedicated for the lube oil storage and pump facility.

5. Site Assessment

5.1 Site Location

The potential greenfield and brownfield site are located on the Avalon Peninsula which is located on the southeastern part of the island of Newfoundland. For this study, a greenfield site was identified for referencing, while Holyrood generation thermal station was identified as the brownfield site location.

5.1.1 Assessment Methodology

The potential greenfield and brownfield site are evaluated for their proximity to a transmission substation, noise considerations, diesel fuel supply, and water availability.

5.1.2 Transmission

The sites are evaluated based on proximity to nearest transmission substation. The Oxen Pond transmission substation is assumed as reference for the sites. Greenfield site is located approximately 15 km to the Oxen Pond substation while Holyrood has an existing transmission line that needs to be further studied for addition transmission capacity. In the absence of this study, the Holyrood site is approximately 30 km from the Oxen Pond substation.

5.1.3 Noise

The distances between the greenfield site to a residential or industrial zone is evaluated to determine the acceptable noise limits. Greenfield site is approximately 6 km, from the nearest residential area. Once a location has been identified, it is important to carry out an environmental assessment reviewing the acceptable noise level. Depending on the report, additional cost may be incurred to mitigate the power plant noise pollution.

5.1.4 Fuel Supply

The greenfield site is located near a major city such as Mount Pearl, and St. John’s. This makes sourcing and transporting of diesel easily accessible to the plant.

5.1.5 Water Requirement

A municipality water supply review of Bay Bulls Pond water treatment plant, supplying the St. John’s region, revealed a water capacity of 110,000 m^3/day. In a simple cycle power plant, water is mainly used to control NOx emissions. Four (4) units of the GE LM6000 PC will require approximately 500 m^3/day of water for NOx abatement. Bay Bulls water treatment plant is a potential source of raw water for the plant. Further investigation will be required to ascertain the available capacity at the water treatment plant. A license will be required to source water from the municipality. A permit will be required to take water from the ponds.

5.2 Site Ranking

Table 5-1 and Table 5-2 below present the results of the site assessment for each location.

Table 5-1: Grade Descriptions for Site Assessment

Grade	Condition	Description
2	Excellent	• Transmission substation is near site • Fuel and water resources easily accessible • Noise within allowable limits
1	Good	• Transmission substation is far from site • Fuel and water resources accessible • Noise level to be examined.
0	Poor	• Transmission substation must be constructed • Fuel and water resources are not accessible • Noise not within allowable limits.

Table 5-2: Site Assessment for Green Field Locations

Site Criteria	Greenfield Site	Brownfield Site - Holyrood
Transmission Line Availability	2	2
Fuel Supply	1	2
Water Source	2	2
Noise Considerations	2	2

5.3 Assumptions and Limitations

The site assessment has been prepared subject to the following assumptions and limitations:

- Detailed field studies or surveys were not conducted as part of this study. The findings obtained from desktop studies and discussions with relevant stakeholders may not have captured all features and characteristics of the sites.
- Information was collected and sources from public sources and external parties. The accuracy of such information cannot be guaranteed. In addition, some of the data obtained may be outdated.
- This study has excluded direct contact with Network Service Providers, Water Supply Authority, Municipalities, Federal, Provincial authorities, and landowners.

6. Description of Major Equipment

6.1 Combustion Turbine Overview

The following combustion turbine vendors were contacted for the technology screening:

- General Electric
- Mitsubishi Power Aero (MHI)
- Siemens.

All three vendors have experience in the design and supply of gas turbines.

6.1.1 General Electric – LM6000

The technology recommended by General Electric (GE) was the LM6000-PC Sprint gas turbine generator set. The design would involve two gas turbines installed in simple cycle mode. The LM6000 group of turbines has more operating experience than any other aeroderivative gas turbine greater than 50 MW.

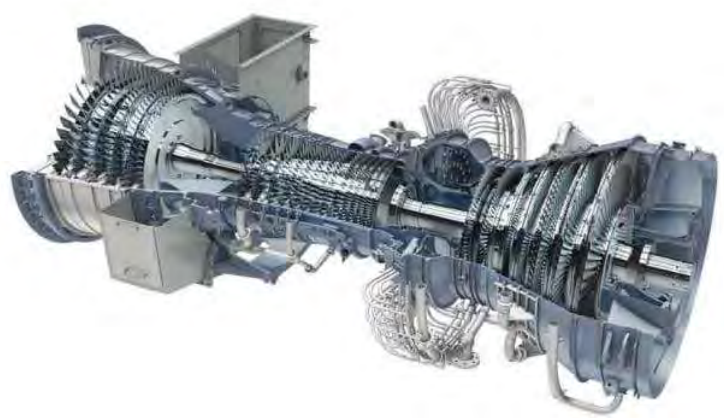

Figure 6-1: LM6000 Gas Turbine Engine

The technology has the following capabilities:

- Achieves emissions standards while ramping up at 50 MW/minute starting as low as 25% of full load.
- Meets various dispatch profiles with 5-minute start and can reach max power in less than 10 minutes.
- Low emissions technology and fuel flexibility (ethane, propane, LPG) with a standard combustor.

The following sections provide further details on the systems:

6.1.1.1 *Combustor Technology*

The LM6000 is fitted with a Single Annular Combustor (SAC) or a Dry-Low Emissions (DLE), combustor. For this project GE selected the Single Annular Combustor. Thirty nozzles supply fuel into the LM6000 annular combustor. This produces maximum output with low thermal stress. The swirl-cup dome design produces a lean thoroughly mixed mixture in the primary zone of the combustor. This provides cleaner combustion, reduces NOx, and helps to eliminate the formation of high-carbon visible smoke. Available nozzle designs allow natural gas, or dual-fuel (distillate/natural) operation. The nozzles also permit NOx reduction with Water injection for NOx (Steam injection is no longer offered). The annular combustor design provides low pressure loss, low exit temperature, low smoke, and high combustion efficiency.

6.1.1.2 *Water Injection*

Water Injection for the NOx System is an available option to reduce emissions on LM6000 PC. The Water Injection for NOx System pumps de-mineralized water to the fuel nozzles via an engine mounted manifold. The water injection motor/pump assemblies, duplex filter assembly, and flow-control valve are located on the auxiliary skid. On natural gas, the LM6000PC can achieve 25 ppm NOx and 42 ppm NOx on diesel no 2.

6.1.1.3 *Fuel Capability*

The LM6000 can run on the following fuels:

- Natural Gas
- Diesel
- Biodiesel
- Ethanol
- Hydrogen blend.

GE confirmed they can burn biodiesel and ethanol in the LM6000 gas turbine. The LM6000 PC package can burn biodiesel and ethanol without any system upgrade. The unit however requires an alternative fuel such as diesel or natural gas for startup operation. They however have limited experience in burning ethanol in their global fleet. Appendix J of this report shows GE reference list burning ethanol and other alternative fuels like Naphtha and Biomass.

The LM6000 can burn 35% hydrogen by volume with major upgrade in the gas turbine. Some of the required upgrades include:

- Fuel blending skid.
- H2 and NG stop/control valves.
- Flow meters, instrumentation, and controls.
- Inert purge system.

- Fuel piping material upgrade.
- Optical fire protection system.
- Gas sensor.
- Ventilation system upgrade.
- Hazardous gas detection system upgrade.
- Software changes.

When specified, the package is furnished complete with two independent fuel systems. This could include two gaseous fuels, two liquid fuels, or one gaseous and one liquid fuel.

6.1.1.4 Winterization

GE provides winterization for the package modules. This consists mainly of heat tracing, which includes a variable speed ventilation fans and controlled ventilation louvers. In addition to the package module, an air inlet heating system is also provided. This is achieved by installing an inlet heating coil that sits in front of the air filters to prevent them from clogging with ice/snow.

For equipment operating in hot or cold climates, GE recommends selecting the ambient thermal condition options to mitigate the site operating conditions. GE will provide winterization of the gas turbine package to -29ºC.

These options may include, but are not limited to:

- Inlet air conditioning (heating or cooling).
- Air conditioning or heaters for some equipment.
- Heat tracing and insulation of applicable unit mounted piping.
- Enclosing and heating exposed instruments and equipment.
- Winterization enclosures for auxiliary skids.
- Variable Frequency Drives for ventilation fans.
- For ambient temperatures below -20°F (-28.9°C), the above modifications plus additional special equipment may be required.

6.1.1.5 Synchronous Condensing

The brush generator is a synchronous, two-pole, cylindrical rotor machine. It has open-air cooling and a brushless excitation system with permanent magnet generator. This power plant operation mode allows the generator to operate as a synchronous motor for grid voltage stabilization at a leading or lagging power factor. The Synchronous condenser mode can ne entered from normal operation or from shutdown condition. When entering this mode from a shutdown condition, the turbine will complete a normal start sequence to breaker closure, after which fuel will be shut off and with the breaker closed the electrical generator/power turbine will turn the gas generator. The synchronous motor can be operated in voltage control to enable support of transmission system requirement.

6.1.1.6 *Balance of Plant – Instrumentation and Controls*

The instrumentation and controls provided will ensure safe and efficient operation of the process over the complete range of operating conditions:

- Gas Turbine Enclosure.
- Lubricating Oil and Hydraulic Oil Systems.
- Lube Oil Cooler: Shell & Tube Cooler.
- Lube Oil Piping and Reservoir.
- Multi-stage Static Air Filtration System.
- Evaporative Cooling for improved performance Exhaust.
- Exhaust Collector and Flange.
- Turbine Control Panel (TCP).
- Generator Monitoring and Integrated Generator Protection System.
- 24 V DC Battery and Charger System.
- Human Machine Interface (HMI).
- Fire Protection System.
- Vibration Monitor.
- GTG Motor Control Center (MCC).

6.1.1.7 *Start-Up*

The GE LM6000 package has the unique ability to reach full power (simple-cycle) from a cold start within 5-minutes for special applications. The gas turbine load ramp rate would be 500 kW/sec, a total of 90 seconds to full load.

6.1.2 *MHI – FT4000*

Mitsubishi Power Aero LLC supplies aero-derivative gas turbine packages that generate 30 to 140 MW, tailored and responsive aftermarket services, turnkey EPC expertise, and battery storage.

Figure 6-2: FT4000 SWIFTPAC Aero-Derivative Gas Turbine

The FT4000 has the following features:

- Enables a start-up time of less than 5 minutes from cold start.
- A load change rate of 50% per minute.

6.1.2.1 *Combustor Technology*

The FT4000® gas turbine utilizes a dry low NOx combustor and is furnished with 24 external radially mounted fuel nozzles for liquid distillate fuel, natural gas fuel, or dual fuel depending upon the fuel system specified by the customer. The combustion system can achieve 42 ppm NOx without a selective catalytic reducer (SCR) while running on diesel.

6.1.2.2 *Water Injection*

The FT4000 comes with a dry low emission combustor technology that does not required water for NOx emission abatement to achieve a 42 ppm NOx on diesel.

6.1.2.3 *Fuel Capability*

The FT4000 is designed to run on liquid fuel - diesel, and natural gas FT4000 currently can burn 10% hydrogen by volume with a development cycle of attaining 30% by 2025. As of the time of this report, the FT4000 does not have the capability to burn any biofuel such as ethanol and biodiesel.

6.1.2.4 *Winterization*

The gas turbine enclosure and electric generator enclosure are designed for outdoor operation to protect the engine and related equipment from the weather and to reduce noise levels. The stated design temperature range is from -4ºC min/20ºC max. The enclosure is supplied with filtered ventilation air. For installation into building, the inlet and exhaust stacks will need to be ducted. Sufficient access to the enclosure is provided with man doors and equipment removal doors or panels. Sufficient space within the enclosure is provided to allow for normal maintenance and removal of major components.

In cold weather applications, Mitsubishi Power Aero provides a set of engineered systems which allows operations below -14ºF / -30ºC. By using heat tracing and an EG recirculation air damper, the equipment can operate at low temperatures and be resistant to icing.

6.1.2.5 Synchronous Condensing Mode

This mode allows the generator to operate as a synchronous motor for grid voltage stabilization at a leading or lagging power factor selected by the operator. This mode can be entered from normal operation or from shutdown condition. The synchronous motor can be operated in Voltage control or VAR control to enable support of transmission system requirements.

6.1.2.6 Start-Up

Start-up time of less than 5 minutes from cold start with outstanding system stability and a load change rate of 50% per minute.

6.1.2.7 Balance of Plant – Instrumentation and Controls

The following are the balance of plant systems required for the FT4000:

- Gas Fuel System.
- Liquid Fuel System.
- Water Treatment System.
- Compressed Air System.
- Wastewater System.
- Fire Protection System.
- Auxiliary Electrical Systems.
- Medium Voltage Electrical System.
- High Voltage Switchyard/Transmission.
- Civil/Structural Works.

6.1.3 Siemens – SGT-800

6.1.3.1 Technology Overview

The SGT-800 industrial gas turbine combines a simple robust design for high reliability and easy maintenance with high efficiency and low emissions.

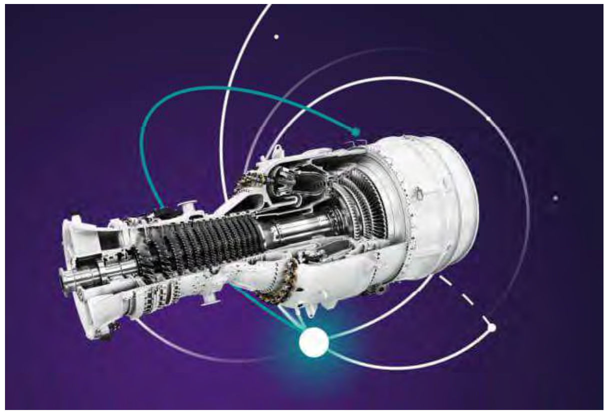

Figure 6-3: Siemens SGT – 800 Gas Turbine

The technology has the following capabilities:

- Broad flexibility in fuels, operating conditions, maintenance concepts, package solutions and ratings to satisfy different market requirements.
- World-class reported fleet reliability of >99.5%.
- Guaranteed 42 PPMV NOx.

6.1.3.2 *Combustor Technology*

The SGT-800 gas turbine package comes with welded 15 stage compressor rotor, 3 stage variable guide vanes (VGV) with a vertically split compressor casing for ease of serviceability. The gas turbine is designed with a single shaft rotor with a rotor speed of 6600 rpm connected to a three (3) stage turbine. Siemens proposed two SGT800 packages rated at 57 MW and 62 MW. The unit price difference between these two-product offering is approximately $1.7 million. The main improvements for higher power and efficiency includes minor changes in the combustor outlet temperature, improved turbine blades and vanes, improved turbine rotor with curvic couplings for robustness and changed heat shield design.

6.1.3.3 *Water Injection*

The SGT800 combustion turbine comes with dry low emission (DLE) combustion system which does not require water injection. The unit us able to achieve 25 ppm NOx (Nitrogen Oxide) on natural gas and 42 ppm NOx on diesel no 2. The combustor consists of 30 DLE replaceable burners with on load fuel changeover capability.

6.1.3.4 *Fuel Capability*

The SGT-800 offers gas only, liquid only (Diesel No.2) or dual fuel (gas/liquid) with on-load fuel-changeover capability. The engine, equipped with DLE burners, is capable to burn up to 75 vol% of hydrogen (H_2).

Siemens has limited experience with biodiesel but confirms its capability. The SGT800 is currently being built in Sweden to run on biodiesel with a commercial operation date of 2023. As of the time of the report, Siemens do not have any experience burning ethanol in their gas turbine fleet. However, they claim they have the technology and is willing to partner with any developer or utility power producer to achieve this capability.

6.1.3.5 Winterization

The turbine generator package will require an anti-icing heater for temperatures below -4 °C.

6.1.3.6 Synchronous Condensing

The water-cooled AC generator comes with synchronizing equipment.

6.1.3.7 Balance of Plant – Instrumentation and Controls

The following are a list of the balance of plant systems:

- Combustion Air Intake System.
- Exhaust System.
- Gas Fuel and Ignition System.
- Lubricating Oil System.
- Cooling Water System.
- Water Cooled AC Generator.
- Electric Start & Barring System.
- Weatherproof Acoustic Enclosure.
- Enclosure Ventilation System.
- Electrical and control module.
- Fire Extinguishing System.

7. Turbine Technology Selection

General Electric (GE) LM6000 PC sprint aeroderivative gas turbine was technically selected as a preferred technology as it meets all the technical requirements of the proposed plant. These technical requirements are:

- Ability to run biofuels – biodiesel and ethanol.
- Synchronous condenser capability.
- Equipment fast start capability under ten minutes (good for peaking plant).
- Ability to burn hydrogen.

The GE LM6000 PC sprint with a 50 MW output on diesel fuel was used in developing a preliminary layout, general arrangement, project schedule and a class 5 cost estimate.

Siemens SGT 800 also meets the technical requirements. The SGT800 gas turbine can only run-on biodiesel as a biofuel with longer start up times. However, the unit can burn more hydrogen blend by volume than LM6000 and FT4000.

MHI FT4000 is designed to burn diesel, natural gas, and hydrogen blend. The gas turbine has no capability and experience in burning biofuels.

See Appendix I for combustion turbine evaluation sheet.

8. Power Plant Performance

As defined in the design basis section, three different models of gas turbines from multiple OEMs were considered for the study. The combustion technology considered includes:

- GE (General Electric) – LM6000.
- Siemens – SGT800.
- MHI – FT4000.

See Appendix A for a detailed summary of the estimated performances from the OEMs burning diesel and biodiesel.

9. Preliminary Process Flow Diagram and Plant Layout

Three (3) preliminary process flow diagrams (PFD) were developed for this study namely:

1. General plant arrangement PFD.
2. Biofuel (biodiesel) PFD.
3. Diesel Fuel PFD.

Four (4) preliminary plant layouts were developed for Scenario 1 and 2 for both greenfield and brownfield sites. The preliminary PFD and plant layout is included in Appendix C.

10. Level 1 Project Schedule

The proposed Level 1 schedule for project execution is included in Appendix E. The level 1 project schedule developed was for two scenarios namely:

- **Scenario 1:** Two (2) units of 100MW nominal simple cycle power plant.
- **Scenario 2**: Four (4) units of 200MW nominal simple cycle power plant.

See Appendix E for a level 1 Gantt chart project schedule.

11. Combustion Turbine Maintenance

Aeroderivative gas turbines maintenance services typically consists of:

- Periodic inspections.

  Period inspection typically includes:

  - Borescope inspection of the engine. This is typically performed approximately every 4000 hour or annually, depending on whichever occurs first.
  - Annual package inspection and controls calibration

- HGPI- Hot Gas Path Inspection

  Hot section and combustor rotable exchange. This is typically performed approximately at 30,000 fired hours on natural gas which could vary depending on the operation and condition of the engine. During this maintenance interval, the existing hot gas path section will be removed, refurbished, and replaced.

- Major Overhaul

  Major Overhaul. This is done at approximately 60,000 fired hours, during which the engine is removed and shipped to the nearest repair workshop for an overhaul. During the overhaul, there is a complete tear down and inspection of engine and rebuilding with new or refurbished components. GE has an optional lease program that provides a lease engine during the major overhaul.

12. Capital Cost Estimate

This section describes the basis of the preparation of the capital cost estimate for the NLH Gas Turbine Screening Study for the power plant. Section 13.2 of this report provides a cost estimate for hydrogen production for hydrogen use in the combustion turbine.

The target accuracy of the capital cost estimates is in the range -20% to + 30% which represents an AACE Class 5 Estimate.

The capital cost estimate was compiled based on the following parameters:

- General Electric - LM6000 PC Sprint budgetary price.
- The Hatch Thermal Power Plant Factored estimate model was used develop the costs by area and system. The Hatch Thermal Factored Model was developed from benchmark data for completed projects and definitive estimates. Refer to Appendix F for the equipment list.
- United States Dollar currency was converted to Canadian Dollar, based on the current exchange rates tabulated below:
  - The average labour rate for all works was established by Hatch.

Table 12-1: Foreign Currency Exchange Rates

Currency Code	Currency	Conversion Rate
Canada	Canadian Dollar	1.00 USD = 1.30 CAN

  - Use of a defined Estimate Breakdown Structure (EBS) aligned to the project Work Breakdown Structure (WBS).
  - An estimate base date of September 2022.
  - All other costs are exclusive of escalation, taxes, and owner's costs.
  - Estimates have been produced in accordance with Hatch Global Estimating Standards.

12.1 Basis of Estimate

Table 12-2 identifies the Basis of Estimate in summary form.

Table 12-2: Summary of Estimate Basis

Commodity	Estimate Basis
Plant and Equipment	
Major Equipment	Budget quotations based on specifications and data sheets. GE price used for the gas turbines 32 million CAD per gas turbine.
Minor Equipment	Factored using the Hatch Thermal Power Plant Factored Model
Bulk Materials & Site Works	
Site Preparation	Factored using the Hatch Thermal Power Plant Factored Model
Concrete	Factored using the Hatch Thermal Power Plant Factored Model
Structural Steelwork	Factored using the Hatch Thermal Power Plant Factored Model
Site Services Piping, and Valves	Factored using the Hatch Thermal Power Plant Factored Model
Tanks	Calculated based on volume of tank, ton of steel, fabrication cost, field erection, and internal Hatch database.
Buildings	Factored using building area and benchmark building costs from Hatch internal database
Electrical	Factored using the Hatch Thermal Power Plant Factored Model
Instrumentation	Factored using the Hatch Thermal Power Plant Factored Model
Control System	Factored using the Hatch Thermal Power Plant Factored Model
Installation	
Installation Labour	Man-hours calculated or based on historical benchmark data.
Vendor Representatives/Supervision	Factored using the Hatch Thermal Power Plant Factored Model
Contractor Distributable/ Preliminaries	Assessed and applied as a cost per man-hour to the unit labour rates by discipline.
Freight	
Freight	Factored using the Hatch Thermal Power Plant Factored Model
Spare Parts	
Commissioning Spares	Factored using the Hatch Thermal Power Plant Factored Model
Operations Spares	Owner’s cost. No Spares Parts have been included in this estimate.

12.2 Capital Cost Estimate

12.2.1 Estimating Methodology

The approach to the estimate preparation was as follows:

- Define the scope of work.
- Structure and code the project into an agreed Estimate Breakdown Structure (EBS).
- Request pricing for Major Equipment.
- Calculate labour man-hour rates for construction work.
- Calculate the labour Productivity Adjustment.
- Establish foreign currency costs and exchange rates.
- Input Major Equipment costs into the Hatch Thermal Power Plant Factored Estimating Model.
- Adjust the model inputs to reflect the specific project scope.
- Determine the costs to carry out the EPCM.
- Establish an appropriate estimate base date.
- Establish appropriate contingency inline with the Hatch Project Life Cycle Process.
- Prepare estimate reports and summaries.
- Undertake estimate reviews.

12.2.2 Direct Costs

Direct costs are factored based on major equipment costs and include all the permanent equipment, materials and labour associated with the physical construction of the permanent process facility, and include:

- Land costs (by others).
- Purchase and installation of permanent plant, equipment, and materials.
- Construction labour.
- Contractor's temporary construction facilities, power, and water.
- General construction plant and equipment.
- Contractor's preambles overheads and profit.

12.2.3 Permanent Equipment

Estimates for major equipment are based on budget quotations derived from vendors using GTG specification data sheets. For minor equipment, costs were factored based on historical benchmark data. See Appendix H for GTG specification data sheet.

12.2.4 Bulk Materials

Bulk materials estimates were developed using the Hatch Factored Model Approach based on the pricing for major equipment.

12.2.5 Installation Costs

12.2.5.1 Direct Field Labour Costs

Direct field labour is the skilled and unskilled labour required to install the permanent plant, equipment, and bulk materials at the project site. Direct field installation man-hours are developed using estimated the Factored Model approach and benchmarked against completed projects.

12.2.5.2 Contractor Indirect Costs

Contractor's indirect costs are costs which are related to the contractor's direct costs, but which cannot easily be allocated to any particular part of them or are not part of the permanent works. For the purposes of this capital cost estimate, these costs are effectively direct costs, and will include the following:

- Contractor's mobilisation and demobilisation, including establishment and later removal and making good, of site offices, storage and other construction facilities, plant, and equipment.
- Contractor's manual indirect and non-productive labour, including time spent in inductions, training, toolbox meetings, clean-ups, bus drivers, crane, and truck operators and store men.
- Scaffolding, safety equipment, personal protection equipment.
- Special construction equipment and special temporary works.

12.2.6 Major and Heavy Lift Cranes

Major and heavy-lift cranes, which are project-specific and outside the scope of contractors' general cranage and plant, were identified and estimated as a direct cost. All general cranage is allocated within the all-in labour man-hour rates.

12.2.7 Construction Labor Rate and Productivity

12.2.7.1 Mechanical Installation Costs

In general, the mechanical installation cost includes:

- Equipment unloading and inspection.
- Storage and storage protection.
- Removal from storage and transport to point of installation.

- Assembly and setting of equipment, leveling, grouting, installation of drive guards, preliminary and final alignments, and balancing.
- First oil fill and cleaning of lube oil piping.
- Installation of on-board equipment.
- Installed integral controls and wiring to first junction box.
- Construction (mechanical completion) testing.
- Touch up painting and clean-up.

12.2.8 Indirect Costs

12.2.8.1 Basis of Estimate for Indirect Costs

During the next phase of the project a thorough study will be undertaken to determine and document the facilities and services required during the construction and commissioning phases.

12.2.8.2 Engineering, Procurement, Construction Management (EPCM) and Pre-Commissioning

The EPCM costs were calculated based on a percentage of the total installed cost (TIC) estimated for the project.

12.2.9 Owner Costs

The Owner's costs have not been included in the estimate.

12.2.10 Project Contingency

Contingency included in the capital cost estimate is an allowance for normal and expected items of work which must be performed within the defined scope of work covered by the estimate, but which could not be explicitly foreseen or described at the time the estimate was completed. The contingency amount is an integral part of the cost estimate. It does not cover potential scope changes, price escalation, currency fluctuations, allowances for force majeure, or other project risk factors or any of the other items that are excluded from the capital cost estimate.

Typical uncertainties applicable to contingency:

- Insufficient information due to incomplete engineering.
- Areas or systems with a reasonable probability of changes occurring during the detail design stage (considered "design development").
- Equipment or material costs obtained by ratio or update from historical costs or previous estimates.
- Labor productivity and costs.
- Project contingency does not cover scope changes or project exclusions. A contingency allowance of 20% is included.

12.2.11 *Freight, Duties and Logistics*

The freight budget, calculated as a percentage of total direct costs, covers the costs for the transportation of equipment and materials from the anticipated market to the plant site.

12.2.12 *Spare Parts*

Allowance to cover commissioning spares is calculated as a percentage of total direct cost.

12.2.13 *First Fills*

An allowance, calculated as a percentage of total direct costs, has been included to fill plant operating equipment and storage vessels with applicable consumables and fluids. This includes, but is not limited to, the first fills of materials listed below (i.e., materials that need to be replaced due to degradation or leakages rather than process consumption).

- Transformer oil.
- Hydraulic fluid.
- Lube oil and grease.

First fills do not include reagents and fuels.

12.3 Estimate Qualifications and Assumptions

The following qualifications and assumption apply to the capital cost estimate:

- The base date of the estimate is generally August 2022.
- Taxes are excluded.
- Environmental Approval Process costs are excluded.
- Owner’s Cost including operations support, site representatives and management costs.
- Financing costs are excluded.
- Camp Costs are excluded.
- Site De-watering costs are not included.
- Costs associated with escalation are excluded.
- Schedule acceleration costs are excluded.
- Schedule delays and associated costs are excluded, such as those caused by:
  - Unexpected site conditions.
  - Unidentified ground conditions.
  - Labour disputes.
  - Lack of Labour Resources.
  - Weather Related conditions.

  - Force majeure.
  - Permit applications.
- Development fees and approval costs of Statutory Authorities are excluded.
- Foreign currency changes from project exchange rates are excluded.
- No allowance for piled foundations has been included.

12.3.1 *Indirect Cost Assumptions*

The following project indirect costs are included in capital cost estimates:

- Construction power and water.
- Heavy haul.
- Performance testing and stack emissions testing (where applicable).
- Preoperational testing, start-up, flushes, cleaning, and calibration.
- Start-up management.
- Initial fills and consumables.
- Construction/start-up technical service.
- Site surveys and studies.
- Engineering.
- Construction management.
- Construction testing.
- Operator training.
- Start-up spare parts.
- Performance and payment bond.
- Subcontractor mark-ups.

12.3.2 *Owner Costs*

Owner costs are not included in the capital cost estimates. Typical Owner's costs include, but are not limited to the following:

- Project development.
- Owner's operations personnel prior to COD.
- Owner's legal costs.

- Owner construction/project management.
- Owner start-up engineering.
- Permitting and licensing fees.
- ECA tax.
- Land.
- Fuel, water, chemicals, and power used during construction and start-up and testing.
- Initial fuel inventory.
- Site security.
- Operating spare parts.
- Permanent plant equipment and furnishings.
- Mobile Equipment (dozers, trucks, etc.).
- Builder’s risk insurance and other insurances such as marine insurance, etc.
- Owner’s contingency.
- Transmission lines or transmission upgrades.
- Connection fees.
- Escalation through COD.
- Interest during construction (IDC).
- Financing fees.

Access road improvements, new access roads, erection of new bridges, modifications of existing bridges, relocation of existing electrical poles or circuits, or other work not directly associated with facility operation within the site boundaries are not considered or addressed in this report.

It is assumed that the labour force is local. Therefore, camp and per diems have not been included for construction labour.

No taxes, import duties, custom clearance, or any other tax associated with the construction of the facility have been included in the cost estimate.

12.4 Capital Cost Summary

The capital cost of each scenario is broken down into direct cost, indirect cost, and contingency. The capital cost estimate is AACE Class 5 Estimate with target accuracy of -20% to + 30%.

Table 12-3 below is a summary of the capital cost for a greenfield and brownfield site.

Table 12-3: Capital Cost Summary

Breakdown of Activities	Greenfield		Brownfield	
	2 x 50 MW	4 x 50 MW	2 x 50 MW	4 x 50 MW
Direct cost	$156,311,000	$272,491,000	$148,107,000	$263,644,000
Indirect cost	$31,033,000	$48,526,000	$30,684,000	$47,225,000
Contingency	$35,906,000	$61,478,000	$34,277,000	$59,537,000
Capital Costs	$223,250,000	$382,495,000	$213,068,000	$370,406,000

See Appendix G for detailed cost estimate summary.

13. Biofuels – Biodiesel/Renewable Diesel/Ethanol

Biofuels can be produced through a variety of different biological and thermo-chemical processes. In general, the terms “Renewable, Green or Drop-in Diesel” and “biodiesel” refer to diesel alternatives derived from biomass. There are two primarily sub-categories of bio-sourced diesels with important differences in their chemical composition due to the different methods of production:

- **Renewable Diesel** is produced through the thermochemical (e.g., gasification, pyrolysis, hydrothermal liquefaction), oleochemical (hydro-processing of lipid feedstock from oil crops, algae, or animal fats), and biochemical (e.g., fermentation) processes for conversion of a variety of feedstocks including lignocellulosic biomass and lipids.
- **Biodiesel** refers to diesel produced through transesterification of lipids (plant and animal oil and fats) or fermentation of crops containing starch/ sugars prior to transesterification. Biodiesel, together with ethanol, were the first biofuels on the market and are deemed first-generation biofuels produced from food-based sources.

Figure 13-1 below demonstrates the different feedstocks and processes to obtain bio-sourced diesels.

Figure 13-1: Feedstock and Processes for Bio Sourced Diesels

The feedstock and production method differentiate biofuels by generation. Figure 13-2 below demonstrates the generations of biofuels.

- **1st generation:** based on "food grade" biomass (e.g., corn and sugar-based ethanol).
- **2nd generation:** a shift towards waste derived feedstock to address socio-political concerns. (e.g., food vs fuel debate).
- **3rd generation**: focus on the on-purpose cultivated feedstock such as algae.
- **4th generation:** derived from specially engineered plants or biomass.

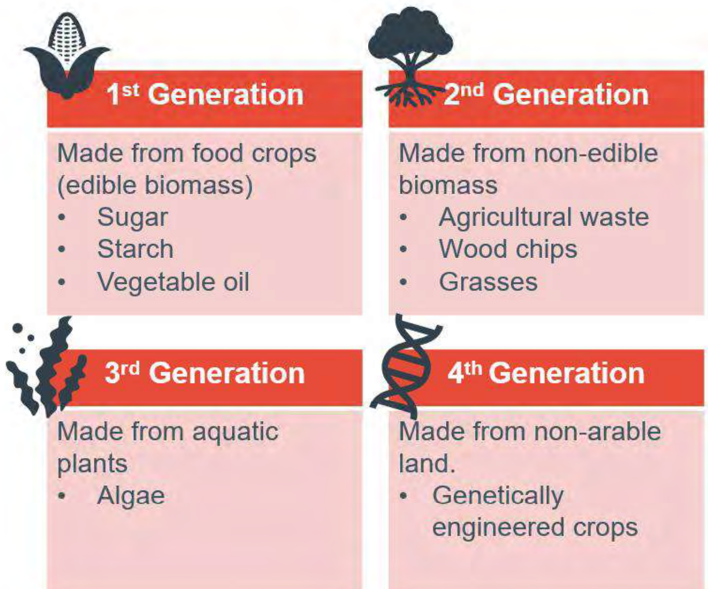

Figure 13-2: Types of Biofuels

The federal Renewable Fuels Regulations (RFRs), which came into effect in 2010 in Canada, requires fuel producers and importers to have an average renewable fuel content of at least 5% by volume for gasoline and at least 2% by volume for diesel. The provinces have been specifying their own mandates that meet or exceed the minimum federal requirements. However, the RFRs will be replaced by the recently published Canadian Clean Fuels Standard (CFS). The final version of the CFS was published in the Canada Gazette on July 6, 2022. It came into force upon registration but however, with the exception of two sections repealing the pre-existing Renewable Fuels Regulations (RFRs), which will come into force on September 30, 2024, [1]. Unlike the RFRs, the CFS requires greenhouse gas (GHG) reductions on a lifecycle basis, accounting for emissions from the production to the end use of the fuel. The CFS establishes lifecycle carbon intensity (CI) limits for each fuel type (gasoline and diesel), expressed in grams of carbon dioxide equivalent per megajoule (gCO2e/MJ) [1]. Primary suppliers must lower the CI of the gasoline and diesel that they produce in Canada and/or import in accordance with these limits. Rather than requiring each primary supplier to calculate the current CI of their unique gasoline and diesel pools, the CFS establishes a baseline CI for each fuel. Primary suppliers must lower the CI of their unique gasoline and diesel pools by an amount equal to the difference between the baseline CI for that fuel and the CI limit for the corresponding compliance period. It may be noted that the proposed CFS would have applied to kerosene, fuel oil, and jet fuel in addition to gasoline and diesel, but these fuels were removed in the final CFS.

Biodiesel

Biodiesel is a substitute for petroleum diesel and is manufactured from plant oil (soybean, canola, corn, etc.,), cooking greases/oils, animal fats, or cellulosic feedstock. Through the chemical process of esterification, the oils are converted into chemicals called fatty acid methyl esters (FAME).

Biodiesel can be blended with petroleum diesel, which is referred to as B*n*, where *n* is the percentage of biodiesel in the blend. For example, B5 is a blend of 5% pure biodiesel and 95% petroleum diesel. Biodiesels are most often blended at B2, B5 and sometimes up to B20 as the specifications at this level do not require equipment modification without risking damage.

Biodiesel versus Renewable Diesel

The major difference between biodiesel and renewable (green or drop-in) diesel is the chemical structure, oxygen content, and distinct properties that impact the extent to which it can be blended in the conventional petroleum diesel. The renewable diesel and can be used in its pure form (called R100) as a direct substitute or mixed/blended with petroleum diesel in any proportion, therefore also termed as “drop-in” diesel. Biodiesel composed of FAME has a higher boiling point (close to maximum for road diesel) and poor cold flow properties (cloud point and cold-filter plugging point) that limits its blending (widely termed as a blend wall) to 5-20% max in conventional fossil fuel-derived diesel.

The point at which crystals start to form in biodiesel (cloud point) compared to petroleum diesel is typically higher. This effects the performance of biodiesel in colder temperatures. To accommodate the lower temperatures performance, low temperature flow additives, or low cloud point petroleum diesel or both are necessary. At a high level, the lower the blend the better the operability in colder weather. A comparison of the types of diesels can be seen in Table 13-1.

Table 13-1: Comparison of Conventional Diesel, Renewable Diesel, and Biodiesel

Parameter	Conventional Diesel (ASTM D975 US No. 2-D S15)	Renewable Diesel	Biodiesel
Chemical structure	-	Oxygen free, straight-chain and branched paraffins (like petroleum diesel)	Fatty acid methyl esters (FAME)
Blending suitability	-	Diesel Substitute (100%) or any proportion	<20% for Fleets; 5-7% Std (ASTM D975 <5%; E590 <7%)
Vehicle and refuelling equipment adaptability	-	No changes required	Modification required (for >5-20% blends)
Adaptability to existing infrastructure	-	Suitable	Material compatibility, deposits/filtration, engine durability issues
Long-term storage stability	-	Stable	Stability issues during long-term storage
Properties			
Cetane number	>40 (>53 in California) >51 in Euro Diesel)	70-80	45-55
LHV, MJ/kg	~43	~44	~37
Density @ 15°C, kg/m^3	Typically 820-840; N/A in North America	770-790	880
Flash point, °C	>52	>59	100-180
Cloud point, °C	Varies based on Ambient Conditions (Beyond <-12^{o}C, Grades No. 1 and No. 2 are blended)	-34 to -5	-13 to 10.5
Viscosity @ 40°C, mm^2/s	2-4	2-5	3-11
Composition			
Carbon, wt%	~87	~85	~76
Hydrogen, wt%	~13	~15	~13
Oxygen, wt%	0	0	~11
Sulfur, ppmw	<15	<5	<5

Ethanol

Ethanol or ethyl alcohol is made from sorted municipal solid waste and from agricultural and forestry crops and residues. Feedstocks for ethanol production vary by region depending on the availability of crops and/or residue. United States and Brazil are the major Ethanol producers, In North America ethanol is typically sourced from corn or wheat grain while in Brazil it is typically sugar cane, and also cellulosic feedstock in both areas.

Besides ethanol being a renewable fuel, its higher oxygen content and complete burning (lower emissions), ethanol has a higher-octane number than gasoline which contributes to its premium blending properties. Most of the gasoline in Canada contains 10% ethanol.

Sourcing

The production capacity of biofuel has grown significantly over the last decade. As of 2022, there are 19 operational biofuel production facilities in Canada - 14 as ethanol plants and 5 as biodiesel [2] [2] [3] [3]. All facilities are currently located in Central and Western Canada.

In 2021, Canadian imports of ethanol from the U.S. increased by 8% year over year to 1.3 billion liters. This was driven by higher Canadian fuel usage as well as an increased share of domestic supply being exported - the total production of ethanol within Canada was over 1.7 billion liters with 100 million liters being exported [4]. In 2022, imports from the U.S are expected to be 1.5 billion liters to support an upward trend in the average nationwide blend level [4].

Canada’s biodiesel facilities are export-oriented with only a fraction of the production focused on the domestic market. Approximately 75 to 90% of Canada’s biodiesel is exported, with almost all of it being shipped to the United States driven primarily by the tax credits/incentives and margins.

Overall, the current supply in Canada is not enough to meet the demand required, therefore, there is a very low chance that there will be any availability for domestic supply to Newfoundland and Labrador in the near future. As the biofuel supply chain grows in Canada, provinces near Newfoundland and Labrador such as Ontario, Quebec, Nova Scotia, and New Brunswick may be of interest to NL Hydro to determine their ability to import.

13.1 Biofuel Facilities in Canada

Figure 13-3 shows the current and upcoming biofuel facilities in Eastern Canada that may be of interest to NLH.

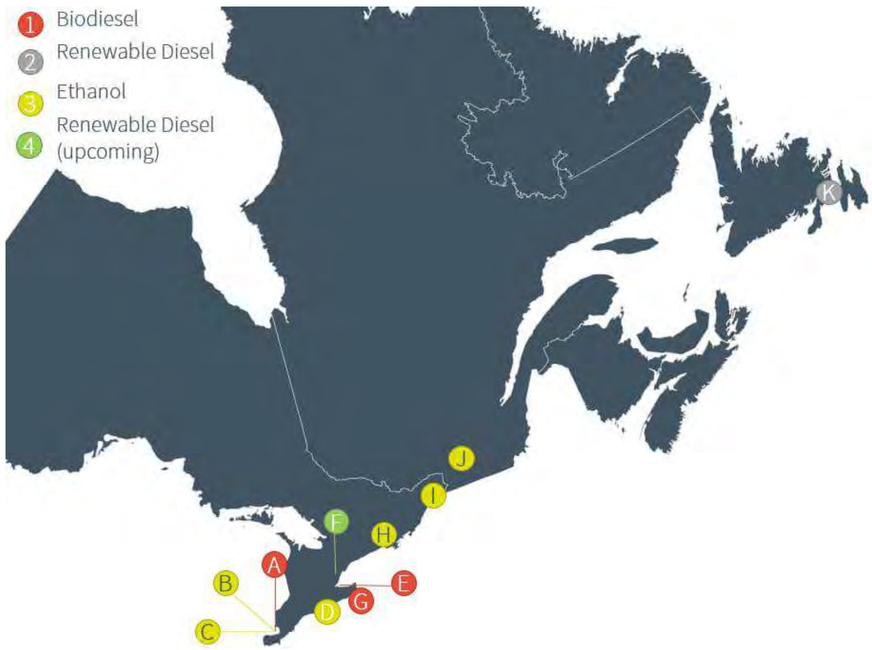

Figure 13-3: Map of Biofuel Facilities in Eastern Canada

Table 13-2 below includes the biofuel facilities from Eastern Canada. The majority of the current production is in southern Ontario, however, there are several upcoming facilities in Ontario, Quebec, and western Canada.

Table 13-2: Biofuel Facilities in Eastern Canada

Map	Name	City	Fuel Source	Capacity (MMly)
A	World Energy	Sombra, ON	Biodiesel from variety of feedstocks	50
B	Suncor Energy	St. Clair, ON	Ethanol	400
C	Greenfield Global	Chatham, ON	Ethanol	200
D	IGCP Ethanol Inc.	Aylmer, ON	Ethanol	340
E	World Energy	Hamilton, ON	Biodiesel from variety of feedstocks	68
F	Refuel YYZ	Toronto, ON	Renewable Diesel	174
G	Verbio North America Corp.	Welland, ON	Biodiesel from vegetable oils	170
H	Kawartha Ethanol Inc.	Havelock, ON	Ethanol	80

Map	Name	City	Fuel Source	Capacity (MMly)
I	Greenfield Global	Johnstown, ON	Ethanol	252
J	Greenfield Global	Varennes, QC	Ethanol	190
K	Braya Renewables	Come by Chance, NL	Renewable Diesel	81

13.2 Potential Biofuel Supply Chain

Biofuel import to Newfoundland and Labrador can be accomplished through trucking, shipping, or piping depending on the location and amount required, in a similar manner to conventional fuels such as petroleum diesel.

The movement of refined products in Canada is largely regional due to infrastructure limitations (especially pipelines). The two broad geographic regions include:

- **Western Canada:** Refineries in Alberta and Saskatchewan supply the demand in the Prairies, British Columbia (BC) and the Northern Territories (Yukon, NW Territories and Nunavut). BC has a couple of small refineries as well that supply part of the provincial demand. The Western Canadian provinces are connected by a network of refined petroleum product pipelines that start near Edmonton, transporting product west to the coast (Vancouver) and east into Winnipeg where it can then be railed or trucked to as far as Thunder Bay.
- **Eastern Canada:** Refineries in Ontario and Quebec supply mainly the provincial demands while most of the production from the Atlantic refineries is exported mainly to the United States. There is a network of pipelines that carries refined products from facilities in Sarnia and Nanticoke towards the Toronto area, and another set of pipelines in Quebec that carry refined products west into the Toronto area.

Figure 13-4 below shows the current product flow system for refined products in Canada for export, import and trades. This can potentially apply to biofuels as well when the market becomes more mature.

Figure 13-4: Refined Petroleum Product Flow in Canada **(Canadian Fuels Association[2])**

13.3 Storage

13.3.1 Biodiesel

In general, biodiesel can be stored similarly to petroleum diesel with a few additional considerations. Solutions for biodiesel storage handling include insulation, agitation, and heating systems. Fuel pumps, lines and dispensers must be protected from cold and wind with proper heating equipment. Unless B100 is stored in underground tanks, it must be stored in insulated and heated tanks, pipes, and pumping equipment during winter months. B100 must also be transported in heated tanks in winter.

Long term storage of biodiesel can pose problems due to slightly different summer and winter blends, degradation caused by temperature fluctuations, and exposure to oxygen. Oxidation of the fuel can cause organic acids, water, and methanol to form in the fuel which will cause problems for fuel consumption and delivery systems. This becomes more of a concern at more concentrated blends, around B20 or higher. Table 13-3 below summarizes storage concerns with biodiesel.

Table 13-3: Biodiesel Storage Considerations

Storage Consideration	Explanation
Contamination Concerns	The flash point of biodiesel significantly lowers if there is methanol or ethanol present in the fuel, allowing it no longer to be handled like petroleum diesel. Low flash point is a safety hazard and may also lead to decreased lubricity, corroded injectors, and degraded materials in the fuel distribution system. Biodiesel also has higher tendency to pick up and dissolve water than that of traditional diesel fuels, which can lead to microbiological growth and requires consideration of measures to prevent water contact.
Storage Length	Biodiesel typically has a “use before” date and should provide six months of storage capability before unacceptable degradation occurs. While Biodiesel is known to have a shorter shelf than most petroleum diesels, but additives can be used to ensure a longer storage life.
Storage Condition	Heat and sunlight can accelerate the oxidation process to degrade biodiesel, and therefore should be avoided. Also, avoiding exposing biodiesel to oxygen during the storage can also help to extend the shelf life.
Storage Transition	Fuel systems should be thoroughly cleaned and dried before using biodiesel to minimize possible corrosion and contamination. Esters have a solvent effect at higher concentrations and resulting sedimentation and deposits issue. These risks are lesser with lower blends of biodiesel (< B35).
Transport	Biodiesel can be transported like petroleum diesel fuel, through tanks or piping made of aluminum, carbon steel or stainless steel. These should be properly washed, dried, and inspected before loading to avoid contamination. [5]

Storage Consideration	Explanation
Cold Temperature Restrictions	Biodiesel will form crystals in cold weather which can cause issues such as plugging filters. Biodiesel should be stored at temperatures at least 2.5-5 °C higher than the cloud point. Biodiesel blends form crystals at temperatures higher than petroleum diesel. Solutions to address this include using fuel additives and fuel filter heaters.

13.3.2 *Renewable Diesel*

Like biodiesel, renewable diesel can also be stored similarly to petroleum diesel however, unlike biodiesel, it does not have cold temperature concerns.

Table 13-4 summarizes storage attributes regarding renewable diesel.

Table 13-4: Renewable Diesel Storage Considerations

Storage Consideration	Explanation
Storage Length	Renewable diesel does not have long-term storage stability issues and can be stored for up to similar length as petroleum diesel.
Storage Condition	There are no additional oxidation concerns with renewable diesel, although it should still be stored under cool and dry conditions like petroleum diesel.
Storage Transition	Fuel systems should be thoroughly cleaned and dried before using renewable diesel to minimize possible contamination.
Transport	Renewable diesel can be transported like petroleum diesel fuel, through tanks or piping made of aluminum, carbon steel or stainless steel. These should be properly washed, dried, and inspected before loading to avoid contamination. [5]
Cold Temperature Restrictions	Renewable diesel does not have cold temperature restrictions. It can operate in similar temperature ranges as petroleum diesel.

13.3.3 *Ethanol*

Ethanol is much safer than gasoline and diesel, having no toxic or carcinogenic properties, and is fully biodegradable. However, once blended, the harmful properties of the gasoline or diesel still apply to the fuel blend. Ethanol, and ethanol-blended gasoline, however, has high affinity to pick up water and therefore cannot typically be transported by pipeline.

Table 13-5: Ethanol Storage Considerations

Storage Consideration	Explanation
Contaminant Concerns	Ethanol, and ethanol-blended gasoline, has high affinity and ability to pick up water and therefore cannot typically be transported by pipeline. It is typically shipped by rail or truck and blended into gasoline at the terminal.
Compatibility/Material Considerations	Ethanol blends may impact materials in fueling systems such as metallic and elastomer materials. Manufacturers have upgraded materials and developed products that are compatible with E25-85 blends. Fuel systems certified for E85 are known as flex fuel vehicles (FFV). Many elastomer products such as hoses and seals have been upgraded in fueling equipment to accommodate for a range of fuels. Blends below E25 may impact elastomers and contact with E85 causes some elastomers to swell. [6] Materials that can store ethanol include thermoset-reinforced fibreglass, thermoplastic piping, and thermoset-reinforced fibreglass tanks. Other materials have been proven to degrade with prolonger contact to ethanol.
Storage Condition	Most existing tanks are compatible with ethanol blends above E10 [6]. Ethanol has the tendency to absorb water from the surrounding environment. As such tanks must be cleaned to store ethanol blends. Debris and moisture can build up over time to form water bottoms in the tank which due to the solubility of ethanol in water can cause the fuel to become contaminated [6]. As such is should be stored in dry areas with low humidity. All tanks storing E85 blends should be double walled and made of steel, fibreglass-jacketed steel, or UL-listed fibreglass.
Storage Transition	Fuel systems should be thoroughly cleaned and dried before using ethanol to minimize possible contamination.
Transport	Like storage conditions, ethanol compatible materials should be used to transport and dispense the fuel. As stated above, pipeline transport at larger scale is typically avoided to prevent water contamination.

13.4 Economics

Currently, biofuel costs in Canada are higher than their petroleum or conventional counterparts, with biodiesel and renewable diesel being 1.5 and 2 times higher than petroleum diesel. E85 has always been $0.2-0.3 cheaper than gasoline per gallon, but it is more expensive on an energy equivalent basis. This cost difference is mostly due to the high production cost as well as lack of low-carbon fuel incentives and policies in place. Since there are no policies currently in place to push the use of biofuel, there isn't a need for domestic usage, so current production in Canada is mostly shipped elsewhere where there is a market and incentives (as in the US) for biofuel. There are no incentives in place in Canada to help the biofuel producers with production cost. Since biofuel production costs are higher than petroleum products, this increase in cost is either pushed onto the buyer, or the supplier will sell it into a region that has incentives in place.

The Canada Clean Fuel Standard (CFS) is a federal regulation that is working to incentivize investment and growth in the clean fuel sector, and it is one of the pioneer regulations for Canada as a whole. As stated previously, the regulation will increase the CI reduction requirement and increase the need for alternative fuels in the country, which in return should increase production to drive down the prices.

Unlike Canada, the US, specifically the west coast region (California, Washington State and Oregon) currently has the most advanced/established regulatory environment for alternative fuels in North America. In the US, alternative fuels and their petroleum counterparts are very similar in pricing. In California specifically, biodiesel has been cheaper than petroleum diesel since 2018.

Table 13-6: Average Fuel Price Comparison Between Canada and the US

Fuel (Q2 2022)	Average Price in US (CAD/L)* [7]	Canadian Average Price (CAD/L) [8] [9] (Global Fuel Prices)
Diesel	$1.66	$1.80
Biodiesel B20	$1.56	$2.30
Biodiesel B99-B100	$1.71	$2.70
Renewable Diesel	$1.67	$3.60
Gasoline	$1.40	$1.89
Ethanol (E85)	$1.20	$1.67

Note *: Exchange rate used is 1 USD = 1.28 CAD

14. Hydrogen

In recent years hydrogen has gained significant momentum globally due to the potential to help create clean energy solutions. The number of policies and projects around the globe are growing at an unprecedented rate regarding hydrogen integration and development. Today hydrogen is primarily used in the refining and chemical sectors and produced from fossil fuels.

Hydrogen is light, storable, reactive, has a high energy content per unit mass, and can be readily produced at industrial scale. The growing interest in hydrogen for clean energy systems is based on two additional attributes: it can be used without direct emissions of air pollutants or greenhouse gases (GHG); and it can be made from a diverse range of low-carbon energy sources. It offers a way to decarbonize a range of sectors, including long-haul transport, chemicals, steel, and power.

There are many technologies available today to produce, transport, and store hydrogen. Although hydrogen is a clear gas, the "colours" of hydrogen refer to the method in which it is generated. This includes the following categories of hydrogen production:

- **Grey**- produced from natural gas via steam methane reforming (SMR). Steam and natural gas react at high temperatures and pressures to produce hydrogen and carbon dioxide (CO_2). This is currently the dominant technology for large-scale hydrogen production.
- **Brown -** produced from coal gasification to create a synthetic gas of carbon monoxide (CO) and CO_2, hydrogen, and steam from which the hydrogen is extracted.
- **Blue**- blue hydrogen uses the same production method of grey or brown with the difference being the resulting CO_2 is captured instead of being released to the atmosphere.
- **Green**- produced through electrolysis using renewable energy source. Hydrogen electrolysis is the process of running an electrical current through water to separate the hydrogen from the oxygen.
- **Purple/Pink**- produced through electrolysis using nuclear energy source.

Hydrogen has the potential to be used for medium to long term energy storage. Several power plants around the world are being converted to use both natural gas and hydrogen with the potential to transition in the future to 100% hydrogen.

Issues with low round-trip efficiency are present with large scale hydrogen storage. This is from the process of converting electricity through electrolysis into hydrogen and then hydrogen back into electricity.

Green hydrogen is produced through the electrolysis of water and requires significant amounts of renewable electricity. When green hydrogen is used in turbines, the final output is electricity with ~ 25% round-trip efficiency (electricity-to-electricity) as demonstrated below:

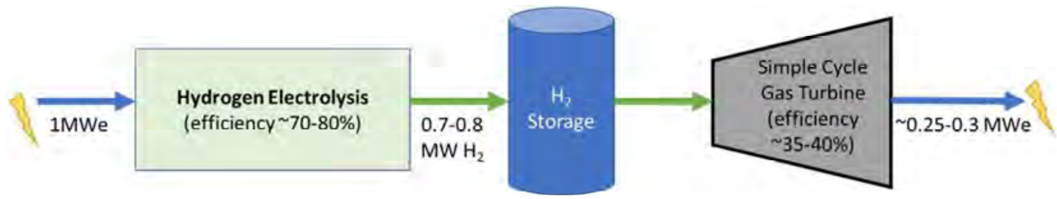

Figure 14-1: Schematic of "4-to-1" Round Trip Efficiency of Green Hydrogen to Electricity*

**The storage component shown here is for illustrative purposes only and can represent compressed, liquified, or ammonia-based hydrogen storage.*

This 4-to-1 round trip efficiency results in substantial degradation of final electrical output compared to the original electrical input.

14.1 Sourcing

There is currently no established hydrogen supply chain in Newfoundland and Labrador. To maximize emission reduction when using hydrogen for power generation, the process by which hydrogen is produced, or its "colour", is a key input. For this study, only low carbon hydrogen production was considered.

The refinery located in Come by Chance is the sole user of hydrogen on the island and it is produced and consumed onsite. The hydrogen is produced from butane feedstock, which is imported to the facility, and would be considered grey hydrogen.

Newfoundland and Labrador's proximity to natural gas reservoirs (blue or grey hydrogen production) and its renewable energy sources in hydropower and wind (green hydrogen production) show the large potential for hydrogen production in the province. However, the province is not currently projected to have a large domestic demand and most of the production being considered is for export markets [10] [10].

14.1.1 Hydrogen Projects in Eastern Canada

There has been recent development in the hydrogen industry within Eastern Canada. Some of the more notable projects are listed below. While these projects are in their infancy there is potential to work with developers to import hydrogen to the island.

1) **Point Tupper, Nova Scotia-** EverWind Fuels LLC is scheduled to begin production of a green hydrogen facility in 2025. [11] The company plans to convert the former NuStar transshipment terminal into a producer for hydrogen.

2) **Bear Head, Nova Scotia-** Buckeye Partners LP has completed a takeover of Bear Head LNG. They have outlined plans to remake the export project into a large-scale green hydrogen and ammonia production facility. The electrolyser capacity is expected to be over 2GW [12] [12].

3) **Saint John, New Brunswick**- Irving Oil purchased a 5MW electrolyser from Plug Power Inc. Plug Power is a leading provider of hydrogen solutions. The electrolyser is a proton exchange membrane (PEM) system and will be used at the refinery for the production and distribution of hydrogen. [13] The initial phase of the electrolyser will be powered by the local grid and generate 2 tonnes of hydrogen per day for refining and mobility applications. Irving stated the electrolyser will allow the company to produce hydrogen in a “clean” way. Irving plans to continue to work with the province of New Brunswick to decarbonize the grid and ensure the electricity being used to power the electrolyser is as clean as possible [14] [14].

4) **Varennes, Quebec-** Hydro-Quebec awarded an engineering contract to Thyssenkrupp to oversee the construction of an 88MW water electrolysis plant. The plant is expected to produce 11,000 tonnes of green hydrogen annually [15].

5) **Port Hawkesbury Paper-** Charbone Hydrogen Corporation signed a memorandum of understanding with Port Hawkesbury Paper to which both parties are entering discussions to develop a partnership for the establishment of Charbone’s first small-scale green hydrogen production facility in Atlantic Canada. It is expected that Charbone will be the facilitator of the sale and distribution of the green hydrogen within the Maritime provinces [16].

6) **H2V Energies Quebec-** the facility will use plasma gasification technology to convert raw residual biomass materials such as waste wood and paper into syngas to produce green hydrogen with electrolysis. The estimated production capacity is 49,000 tonnes. The pure compressed hydrogen will start this year at a price of CAD $3.50/kg [17] . The facility is set to be constructed in Beacancour Industrial Park and scheduled for production in 2024 [18].

Figure 14-2: Map of Hydrogen Projects in Atlantic Canada and Quebec

14.1.2 Hydrogen Projects in Newfoundland and Labrador

There has been a more pronounced interest in the hydrogen market in Newfoundland and Labrador in the last 6-12 months. As a result, the provincial government recently announced its plans to open crown land for wind development. There is also interest in developing wind-to-hydrogen projects on the Island. Recently the Government of Canada and Germany signed a “joint declaration of intent” to establish a transatlantic Canada-Germany supply corridor and start exporting hydrogen by 2025 [19]. This announcement was made in Stephenville, Newfoundland, and Labrador the proposed site for the World Energy GH2 Hydrogen project. At this moment it is anticipated that the majority of these projects would focus on export markets. Some of the more notable projects announced shown in Figure 14-3 and described below.

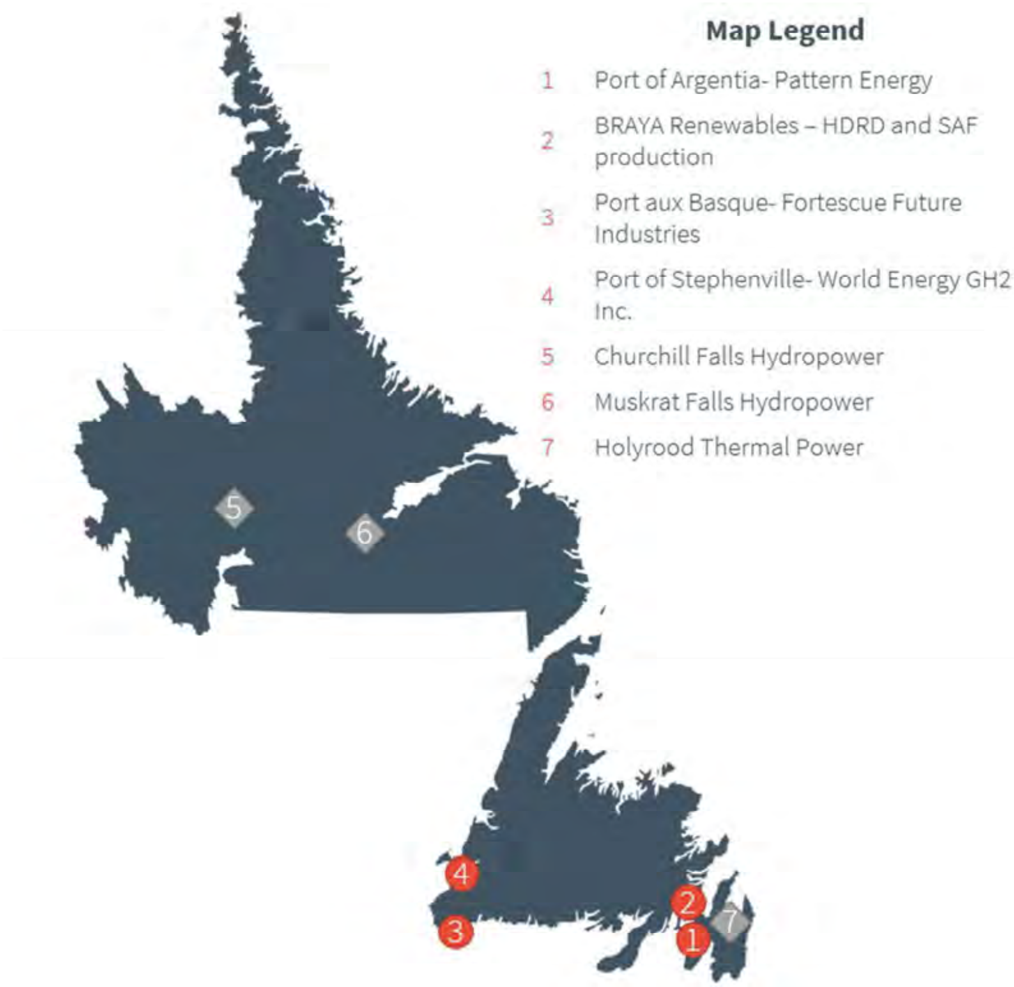

Figure 14-3: **Map of Potential Hydrogen Projects and Major Power Generating Stations in Newfoundland and Labrador**

Note: Brookfield Renewables has not announced a location publicly for a proposed hydrogen development.

BRAYA Renewables

The refinery in Come by Chance is currently the only hydrogen production in the province. The hydrogen is grey and produced through steam-methane reforming. The hydrogen is used in the refining process. The refinery has been converted to produce hydrogenation-derived renewable diesel and sustainable aviation fuel at 18,000 barrel a day using a variety of renewable feedstocks.

Port of Argentia and Pattern Energy

In June 2022, the Port of Argentia announced it had signed an Option-to-Lease agreement with Pattern Energy Group to advance the development of a multi-phase renewable energy project in Argentia. The proposed project is a wind energy project to generate green hydrogen and derivative renewable fuels along with an export facility [20]. The project is expected to be 100-200 MW.

Pattern Energy operates around 6 gigawatts (GW) of renewable energy globally [21]. Pattern Energy plans on investigating the commercial feasibility of wind energy and green hydrogen production at the port through the Option-to-Lease Agreement.

World Energy GH2 Inc. Port au Port-Stephenville Wind Power and Hydrogen Generation

World Energy GH2 Inc. has proposed to construct a maximum 1 GW, 164 turbine onshore wind farm on the Port au Port Peninsula, with associated transmission and supporting infrastructure to power a 0.5 GW hydrogen/ammonia production facility in the port of Stephenville.

The proposed project named project Nujio'Qonik GH2 registered its environmental assessment in June of 2022. On August 5^{th,} the Minister of Climate Change ordered a full Environmental Impact Statement (EIS) to be completed. Any areas of the proposed project that overlap with protected areas, private land, mining operations, mineral licenses, and leases, as well as recreational and traditional land uses must be identified along with a potential project redesign.

Phase 1-Onshore (Current Scope of Registered Environmental Assessment):

- Up to 1 GW onshore wind Generation.
- 0.5 GW Green Hydrogen Production.
- 230 kV interconnection to electrical grid.
- 3x50 MW gas turbine generators (fueled primarily by hydrogen).
- 700 gallons/minute industrial water supply.
- Hydrogen processing facility at the port of Stephenville.
- Grid interconnections and the hydrogen-fuelled turbine generator at the Port.

Phase 2 Onshore Expansion (subject to separate regulatory requirements):

- 1.0 GW additional through onshore wind.
- 0.5 GW Green hydrogen production.
- 350 gallons per minute industrial water supply.
- Switchyard expansion.
- Concurrent expansion of the hydrogen plant.

Phase 3 Onshore Expansion (subject to separate regulatory requirements):

- Evaluate further wind resource potential in the region and potentially expand further.
- 1.0 GW additional through onshore wind.
- 0.5 GW Green hydrogen production.
- 350 gallons per minute industrial water supply.
- Switchyard expansion.

The proposed phases of the project and location can be seen in Figure 14-4 below.

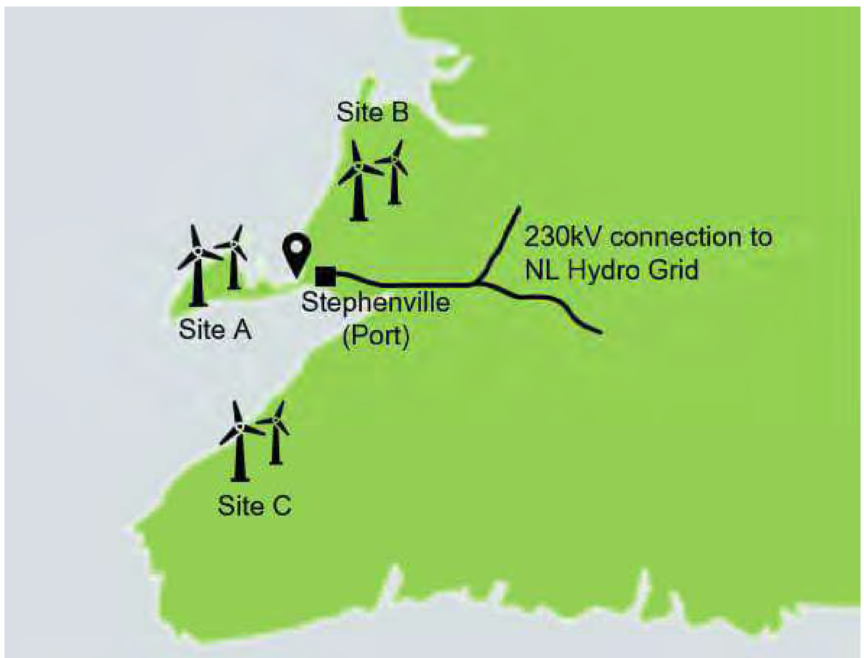

Figure 14-4: World Energy GH2 Project Proposed Location [22]

The plant layout for the production facility can be seen in Figure 14-5 below:

Figure 14-5: World Energy GH2 Hydrogen Facility [22]

Brookfield Renewables

Another major player with reported interest in a hydrogen project in the province is Brookfield Renewables. While the company has been less forthcoming about its plans to develop hydrogen in the province it has recently released it plans to wind generation of 250MW to power a 240MW hydrogen facility [23]. The estimated cost is $2 billion CAD. However, the company has not yet disclosed if they have a location in mind. The company has partnered with German energy firm Uniper and anticipated export of hydrogen by 2027.

Fortescue Future Industries

Australian company Fortescue Future Industries has been investing in green energy projects around the world. They have signed numerous deals for feasibility studies in countries such as Brazil, Indonesia, and Afghanistan. As part of their global assessment, the company investigated opportunities in Newfoundland and Labrador. In 2021, the company was reviewing the 2,500 MW generating capacity in Gull Island [24].

The company has recently proposed a 2,000MW wind to green hydrogen facility on the west coast of the island of Newfoundland. The project is called Project Lynx and consists of 400 wind turbines, a hydrogen production facility, ammonia conversion and a marine export facility. An estimated 700,000 to 900,000 tonnes per year of green ammonia would be produced exclusively for export.

It was reported in July that the company is looking at Searston, Doyles, South Branch, Codroy Pond, and Gallants for the turbine location. For the hydrogen facility the company is looking at Port aux Basque, Turf Point and Stephenville. The company would expect construction to start in late 2026 and have it operational in 2029.

Fortescue Future Industries has signed a Memoranda of Understanding (MoU) with the Miawpukek First Nation to explore the feasibility of a project to produce hydrogen on the southwest coast of Newfoundland and Labrador.

14.1.3 Hydrogen Carriers

14.1.3.1 Liquid Hydrogen

Liquid Hydrogen is one of the primary options for transporting hydrogen over long distances. The primary advantage of transporting liquid hydrogen is its increased density compared to gaseous hydrogen when it comes to transporting large quantities of hydrogen.

Gaseous hydrogen is liquefied when its temperature is cooled below -253°C at atmospheric pressure. At this temperature, the density of liquid hydrogen is about 800 times that of gaseous hydrogen at standard temperature and pressure and approximately 1.7 times higher than compressed hydrogen at 800 bar.

Hydrogen liquefaction is currently very energy intensive, and it typically consumes around 30% of its energy content.

In North America there are currently liquefaction plants ranging in size from 6 to 80 tonnes per day of hydrogen, with most of these plants located in the U.S.

14.1.3.2 Ammonia (NH3)

Ammonia can be used to transport hydrogen long distances, but it is also currently used in different industries such as a raw material for fertilizers and chemical production.

Ammonia is currently produced industrially through the Haber-Bosch process. This process has been well-established since 1918, where it was used in the chemical industry. The process combines hydrogen and nitrogen at high pressure and temperature to produce ammonia.

For end-users that ammonia is not the feedstock it will be required to be dissociated back to hydrogen and nitrogen.

14.1.3.3 Liquid Organic Hydrogen Carrier (LOHC’s)

Liquid organic hydrogen carriers are organic compounds that can be used as a storage media for hydrogen. This technology is relatively new compared to liquid hydrogen and ammonia.

The concept of LOHC’s is to use organic compounds that can absorb and release hydrogen through chemical reactions (hydrogenation and dehydrogenation) to carry hydrogen as a liquid.

14.1.4 Transportation of Hydrogen

As there is currently no established hydrogen supply chain in Newfoundland and Labrador, different methods of importing hydrogen would need to be evaluated. Hydrogen has a high gravimetric energy density but a relatively low volumetric energy density. This directly relates to a higher storage and transportation cost. As a result, hydrogen is typically produced near its end user. However, as the forecasted global demand for hydrogen is expected to increase, a greater emphasis has been placed on transportation.

This section provides an overview of the main methods that could be considered for importing hydrogen in Newfoundland and Labrador.

14.1.4.1 Pipelines

Historically, pipelines have been the most cost-effective method of transporting hydrogen over long distances. Globally there are several pipelines dedicated to hydrogen distribution. Existing infrastructure around the globe is being investigated to be converted to hydrogen transport. The IEA has stated that for distances under 1,500 km transporting hydrogen as a gas by pipeline will likely be the cheapest delivery option.

There is no existing pipeline infrastructure in Newfoundland and Labrador. The capital cost is intensive and social impact would require further evaluation to pursue this option.

14.1.4.2 Shipping

Liquid Hydrogen can be transported by vessel. The Suiso Frontier, built by Kawasaki Heavy Industries, is the world's first liquid hydrogen carrier ship. In January of this year, it completed its first shipment from Australia to Japan. The vessel is capable of carrying up to 1,250 m^3 (90 tonnes) of compressed liquid hydrogen.

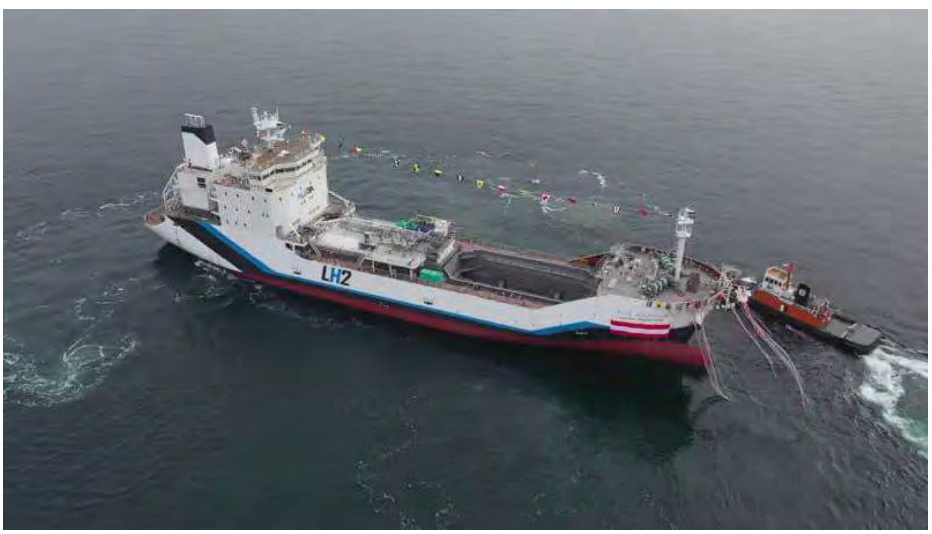

Figure 14-6: Suiso Frontier Liquid Hydrogen Transport Vessel [25]

In April of 2022, Kawaski obtained their Approval in Principle (AiP) for a large 160,000 m^3 (11,400 tonnes) hydrogen carrier. This carrier would be 100 times larger than the Suiso Frontier.

Figure 14-7: Simulated Appearance of the Completed 160,000m^3 Liquid Hydrogen Carrier [26]

Transporting ammonia can be completed using liquefied petroleum gas (LPG) carrier ships. Unlike liquefied hydrogen ammonia has a long history in transportation and does not have the same issues with transporting cryogenic liquids and does not require high-pressure that is required for compressed hydrogen.

During transportation, ammonia is executed in refrigerated ships at low temperatures to keep the ammonia in liquid form. Current ammonia ships have capacities up to 86,700m^3.

Currently LOHC's are not being transported by marine vessel. However, in theory, existing infrastructure for conventional fuel transportation can be used as saturated LOHC can be transported by ordinary oil tankers to the end user. This is advantageous over gaseous and liquid hydrogen as it removes requirements for cryogenic or compressed gases.

Many LOHC carriers such as methanol, toluene and other chemicals are widely transported by vessel around the world today. Methanol can be stored in inorganic zinc/epoxy coated tanks, although stainless steel is preferred. Toluene can be stored in mild steel or stainless-steel tanks and can be transported via vessel.

14.1.4.2.1 Road (Liquid)

Transport by truck on the road in liquid form can transport higher volumes than compressed gas with higher efficiency over shorter distances.

14.1.4.2.2 Road (Gaseous)

Hydrogen can be compressed and transported through tube trailers. The trailers can be mounted to trucks or to barges and transported short distances.

Presently hydrogen is most commonly distributed through compressed gas trailer trucks for distances less than 300km [27]. Currently, single trucks can transport up to 400 kg H2 at 200 bar, with the potential of transporting further compressed hydrogen (500 bar) of up to 1,000 kg H2 [27]. Highly insulated cryogenic tanker trucks can potentially carry up to 4,000 kg of liquid hydrogen and can be used for long distance transport [27].

Table 14-1 below compares present day hydrogen transportation methods.

Table 14-1: Comparison of Transport of H2

Parameter	Unit	Truck (Gaseous) Low Pressure	Truck (Liquid)	Pipeline (Gasous)	Shipping (Liquid)
Pressure	Barg	200	0	30-120	0
Temperature	°C	Ambient	-253	Ambient	-253
Approx. Capacity	Kg of H_2	400 (1)	4,000 (2)	1700/km (3)	90,000 (4)
Approx. Levelized Quantity	-	225 Trucks	25 Trucks	(5)	1 Ship

[1] Capacity is based on a 26 m^3 40-ft tube trailer at 200 barg. Note: Larger transport capacity is expected in the midterm due to lighter composite storage tanks that are being developed.

[2] Capacity is based on a loading volume of $50m^3$.

[3] Capacity is based on 1000% injection in a 36” pipeline at 100 barg and 0°C.

[4] Capacity is based on the Suiso Frontier Ship, the first and only hydrogen transport ship in operation globally.

[5] Dependent on distance from location.

14.2 Green Hydrogen Production

Green hydrogen is produced from electrolysis where water is used to split into oxygen and hydrogen. Alkaline and proton exchange membrane (PEM) electrolysis are the most widely adopted methods of green hydrogen production. Alkaline electrolysis is more mature and commercially developed, but PEM has a faster ramp rate and can be made to be more compact. Table 14-2 shows some of the major differences between the 2 technologies.

Table 14-2: Alkaline and PEM Electrolysis Comparison

	Alkaline Electrolysis	PEM Electrolysis
Process Description	• Uses a liquid alkaline solution of sodium or potassium hydroxide • Operates via transport of hydroxide ions (OH -) through the electrolyte from the cathode to the anode • Hydrogen is generated on the cathode side.	• Water oxidizes to form oxygen and hydrogen ions at the anode when voltage is applied • Electrons flow through an external circuit and hydrogen move across the solid electrolyte membrane to the cathode • Hydrogen combines with the electrons at the cathode to form hydrogen gas
Advantages	• Mature technology • Lower comparative CAPEX • Better scalability	• Compact footprint • Dynamic response • High H2 purity
Disadvantages	• Larger footprint	• Higher component cost

	Alkaline Electrolysis	PEM Electrolysis
	• Low dynamic responsiveness	• Higher degradation rate • Higher projection costs due to precious metal used
Technology Readiness Level (TRL)	9	9

14.2.1 CAPEX

A high-level cost estimate has been produced for a hydrogen production facility based on Hatch's historic costs and expertise on previous studies. A typical hydrogen production plant includes the following components:

- Hydrogen assumed at 99.99% purity.
- Oxygen is vented to safe location and not recovered.
- Cost of H2 and O2 vents included in hydrogen generation cost.
- Buildings for Alkaline technology equipped with overhead crane, fully enclosed with HVAC system, vents for hydrogen and oxygen installed on the roof.
- Average cost of compressor building included for Alkaline and PEM building cost.
- Hydrogen Production includes transformers, rectifiers, electrolyzer stacks, gas separation and scrubbing, Compression if required.
- Substation: Assumes high voltage connection is available at site, conversion into medium voltage 34.5 kV is required through a substation.
- Utilities Cost includes Water Treatment, Instrument Air and Nitrogen, Cooling System, Instrument/Process Control System.
- Indirect cost includes freight, engineering, temporary site facilities, contractor assistance during commissioning, third party services, construction camp, contractors travel and owner cost.

The CAPEX for a 200 MW green hydrogen production facility varies depending on the technology used. Table 14-3 below shows a high-level breakdown of the cost for each technology. Overall, the capex using alkaline is around $425-545 million CAD, and the capex for PEM is between $550-680 million CAD. This would be around $CAD 2.5 MM/MW for alkaline and $CAD 3.0 MM/MW for PEM. Additional Contingency is not included in the CAPEX estimate.

Table 14-3: Budgetary CAPEX for a 200 MW Green Hydrogen Facility

Budgetary CAPEX	Alkaline, MM CAD	PEM, MM CAD
Hydrogen Production (inc. Transformers, Rectifiers, Electrolysis, Scrubbing, Compression if required)	150 – 250	230 – 340

Budgetary CAPEX	Alkaline, MM CAD	PEM, MM CAD
Substation	65	65
Building	20	15
Process Units Subtotal	**235 – 335**	**310 – 415**
Utilities	30	35
Indirect Cost @ 33.5%	90	115
TIC Total (US Gulf Coast Cost)	**355 – 455**	**460 – 565**
TIC Total (NL Cost @ 1.2 factor)	**425-545**	**550 – 680**

14.2.2 OPEX

The OPEX for a 200 MW hydrogen facility is made up of electricity costs, maintenance costs, labor costs, and water costs. Since the electricity cost makes up over 90% of the operating cost for a green hydrogen production facility, a cheaper electricity price can drastically decrease the total OPEX required. The electricity price used for this calculation is based on the current NL Hydro Island Industrial Firm Rate. The SUSEX (sustaining capital) is also a contributing part of the total cost averaged at about $4-6 MM CAD/annum and this is used to replace the electrolyser stacks at the end of their lifetime.

Table 14-4: Budgetary OPEX

OPEX Input	Unit	Alkaline	PEM
Variable Costs			
Chemicals, Catalysts & Consumables	MM CAD/year	negligible	negligible
Water	M3/day municipal water spec.	2340	1281
Water Treatment Costs	CAD/m3	0.5	0.5
Power (Total)	MWh	246-270	245-268
Direct Fixed Costs			
Staffing	Number of employees	14	14
Maintenance	% of direct costs	3	3
Other Fixed Costs			
SUSEX	MM CAD/year	4	6

14.2.3 Production Cost Outlook

According to the International Energy Agency (IEA), it currently costs up to $10.25 CAD/kg ($8 USD/kg) to produce green hydrogen, which is much higher than hydrogen produced from other sources [28] According to previous studies done within Hatch, the current levelized cost of hydrogen produced from alkaline is around $5.5 CAD/kg. Hydrogen produced from PEM electrolysis are expected to be slightly higher.

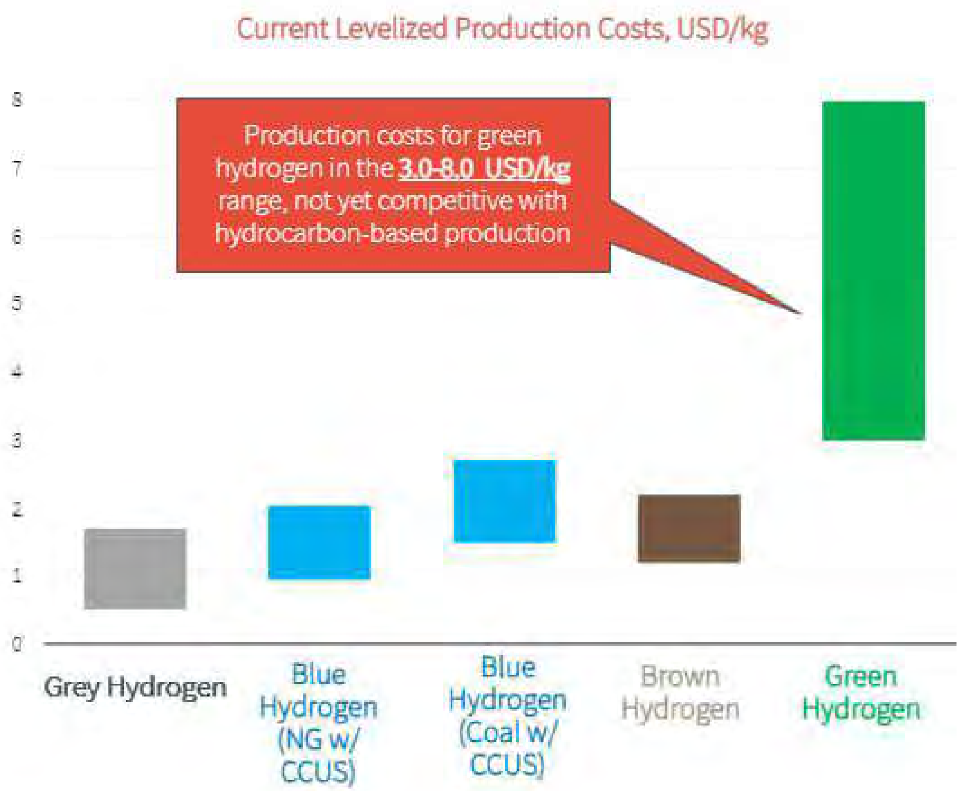

Figure 14-8: Levelized Production Cost of Hydrogen

Green hydrogen production costs are influenced by many technical and economic factors, such as electrolyser scale, production capacity, conversion efficiency and electricity costs. As more commercial-scale applications and large production facilities come online, this will help decrease the capital cost and scale up supply chain. Decreasing renewable electricity cost will also decrease the operating cost since the majority of the OPEX comes from the electricity cost.

Summarized in the IEA's net zero scenario, the price of green hydrogen could decrease to under $4 USD/kg by 2030 and less than $3.5 USD/kg by 2050 which allows it to be more competitive with other types of hydrogen.

14.3 Storage

Hydrogen can be stored in different states depending on the end use and capacity requirements. Currently it is most commonly stored and delivered in either compressed gas or liquid form. The majority is either produced and consumed on-site (around 85%) or transported via trucks or pipelines (15%).

14.3.1 Compressed Hydrogen Storage

Compressing hydrogen to a high pressure increases its density thereby decreasing the volume required for storage. A high-pressure gas steel cylinder is the most common method to store hydrogen with at pressures greater than 200 bar.

Hydrogen gas is typically compressed to 100-825 bar for large-scale storage. The pressure vessels for hydrogen storage can be categorized by four types (I, II, III, IV). In general, the vessels have a central cylindrical section with two spherical domes and polar opening (s).

Table 14-5: Comparison of Tank Types [29]

Type	Material	Liner	Pressure (Max)	Wt.% H2 When Filled
Type I	Metal (Steel)	N/A	200 - 300 Bar	1%
Type II	CFRP frame	Metal	-	2%
Type III	CFRP cylinder and ends	Metal (Aluminum)	450 Bar	-
Type IV	CFRP cylinder and ends	Plastic (HDPE)	1000 Bar	5.5% (350 Bar) 5.2% (700 Bar)

Compressed hydrogen has only 15% (at 700 bar) of the energy density of gasoline. Therefore, storing the same amount of energy would require 7 times the space.

For stationary storage, type I and type II tanks are the most cost effective, typically constructed out of stainless steel.

14.3.2 Liquid H2/Ammonia

Two ways of storing hydrogen, especially for transportation over long distances, are as liquid hydrogen and ammonia.

Liquid hydrogen storage is mainly considered for large production where storage space is limited, when it must be transported over long distances or for industrial applications requiring liquid hydrogen. Hydrogen liquefies at -253 °C and requires cryogenic tanks for storage. These tanks are comprised of two layers separated by a vacuum thermal insulation to avoid heat transfer by convection.

Currently, the largest cryogenic storage tank is a 3,800m^3 spherical tank owned by NASA with a capacity of 270 tonnes of liquid hydrogen [30]. Japan's Kobe LH_2 Terminal has a spherical LH_2 storage tank with a capacity of 178 tonnes (2,500 m^3) [31].

After the hydrogen has been liquefied, it is important to minimize the amount of evaporation during storage. To avoid losses such as boil-off and heat leakage and to prevent any risks due to the physical properties of hydrogen, the boil-off effect must be continuously controlled. The boil-off rate can be reduced by minimizing the surface-to-volume ratio of the tanks by making them spherical and by adding insulation to minimize heat transfer through the tank walls. The boil-off rates for larger insulated spherical tanks are commonly below 0.1% per day [32].

Another method to store liquid hydrogen is using cryo-compressed hydrogen storage which stores hydrogen at cryogenic temperatures in a vessel that can be pressurised. This is a relatively new technology.

Since ammonia is one of the most transported chemicals worldwide each year, infrastructure and facilities for ammonia storage is well developed and efficient [33]. Tanks to store ammonia are often constructed of steel or ductile iron. Composite and aluminum tanks are also compatible with ammonia. Ammonia can react with metals which can lead to corrosion. Therefore, these storage tanks must be monitored and evaluated on a periodic basis to avoid risk of containment failure [34].

Currently, industrial atmospheric/low pressure ammonia storage tanks have capacities from 15,000 to 50,000 tonnes (~24,000 to 80,000 m^3) of ammonia [35] [36].

14.3.3 Geological

Long-term geological storage options for hydrogen include salt caverns, depleted natural gas and oil reservoirs and aquifers. These storage mediums are currently used for natural gas storage. Geological storage has a high efficiency, high storage potential and low operational cost. The types of underground storage can be categories by the type of geology:

- Porous media (e.g., sandstone): this includes depleted oil and gas reservoirs as well as aquifers.
- Cavern Storage: this includes excavated, or solution mined rocks such as salt, coal, igneous and metamorphic rocks.

The basic storage requirements include high porosity, high permeability, ability to hold adequate volumes of gas, ability to extract gas at high rates, contain and trap the gas as well as cushion gas.

Some of the advantages of geological underground storage include:

- Higher storage pressures.
- Smaller surface footprint.
- Higher safety standards.
- Minimization of environmental impact.
- Longer operating lifetimes.

Some of the key challenges associated with geological storage:

- The chemical reactivity of hydrogen gas with minerals, dissolved solutes, microbial metabolisms, and a variety of effects on metals and other building materials.
- High mobility and low viscosity when compared to natural gas. This leads to increased leakage through preferential pathways such as fractures or transport into adjacent aquifers.
- Geological requirements and proximity to end-user.
- Potential chemical reactions with hydrogen that can result in contamination or loss.
- Legal and social obstacles on regulations for land use, etc.
- Cushion gas is the volume of gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates. High cushion gas requirements limit the amount of gas that can be withdrawn.

14.3.3.1 Salt Caverns

Salt caverns are solution-mined cavities within either salt domes or bedded salts. Salt caverns have been used for hydrogen storage in the chemical sector since the 1970’s and 1980’s in the United Kingdom and the U.S. respectively [27]. Salt caverns have an average efficiency of around 98% meaning that almost all the injected hydrogen can be recovered [27]. There is a low risk of hydrogen contamination in salt caverns. The high pressure enables high discharge rates which makes this option attractive for power consumption.

At present Newfoundland and Labrador does not have legislation to allow for storage and recovery of industrial waste in geological media.

Atlas Salt has spent recent years working on a salt deposit project between St. Georges and Flat Bay on the West Coast of the island of Newfoundland. The intent of the project is to mine and sell road salt to consumers on the eastern seaboard. The company is now looking at alternative applications for the deposit with particular interest in the storage of hydrogen [37]. Salt caverns typically require between 20-30% of the total capacity to be cushion gas.

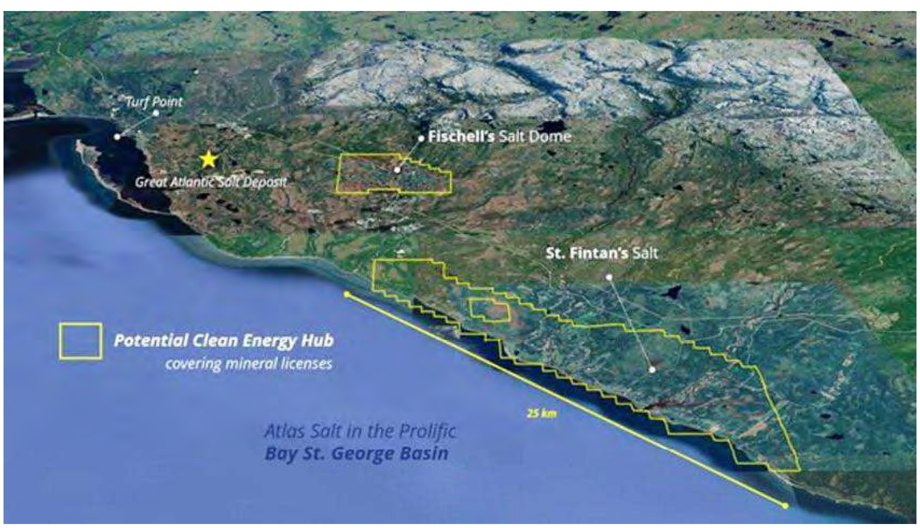

Figure 14-9: Atlas Salt [37]

14.3.3.2 Depleted Oil and Gas Fields

Depleted oil and gas fields are typically larger than salt caverns. However, they contain contaminants that would be required to be removed prior to the hydrogen being able to be used.

Newfoundland and Labrador has an active offshore oil industry. However, due to the location of the fields with the closest field greater than 300km offshore, it is uneconomical to store hydrogen in depleted fields for onshore applications.

Depleted oil and gas reservoirs typically require 50% of the total capacity to be cushion gas.

14.3.3.3 Aquifers

Aquifer storage is like storage in depleted hydrocarbon reservoirs; however, aquifers are the least mature of the geological storage opportunities. The following conditions must be met for an aquifer to be suitable:

- Top of the aquifer is sealed by an impermeable layer of rock.
- The presence of a dome-shaped structure to hold the injected gas in a defined space.
- High permeability of the aquifer with adequate pore space.

Significant investment for exploration is required to establish these characteristics. Consideration also needs to be given to the potential for hydrogen reacting with minerals present, which can result in both depletion of stored hydrogen and contamination. Hydrogen can also react with microorganisms, which could block the pore spaces and lead to the loss of stored gas.

The advantage of aquifers over depleted oil and gas fields is that there is no risk of contamination with hydrocarbon residues.

Aquifers typically require 50-80% cushion gas of the total capacity of the space.

14.3.4 Other Storage Methods

Hydrogen can be chemically stored by absorbing or reacting with other chemical compounds such as metals. Metal hydrides is type of hydrogen chemical storage and has the ability to store hydrogen at high densities that can exceed liquid hydrogen. The challenges of storing hydrogen in chemical from are related to the hydrogenation and dehydrogenation process which has high temperature and pressure requirements.

Other emerging storage opportunities include circular methanol, dimethyl ether, and liquid organic hydrogen carriers.

14.3.5 Comparison of Storage Mediums

The following Table 14-6 outlines some of the advantages and challenges with the different methods of storing hydrogen.

Table 14-6: Comparison of Storage Mediums

Technology	Advantages	Challenges	Potential Use
Compressed Gaseous	• Proven technology • Easily scalable	• Compressor cost, reliability, and efficiency loss	• For shorter distance transportation within NL
Liquid H2/Ammonia	• Large capacity for given footprint • Proven technology	• Cost of liquefication/conversion capital • Energy intensive and efficiency loss, boil-off losses • Difficult to scale easily • Requires reconversion to gaseous H2	• For long distances (e.g., shipping) • For applications requiring LH2 or NH3
Geological	• Highest capacity for large generating plants and/or long-term storage • Can be easily scalable for salt beds	• Requires favourable geological formation nearby	• Suited for long-term storage and very large quantities of hydrogen

Based on a storage requirement for 130MW output for 5 days. Table 14-7 estimates the storage volume based on the hydrogen carrier.

Table 14-7: Storage Tank Volumes

Medium	Storage Volume (m^3)
Compressed hydrogen (CH2) at 350 bar	~58,000
Liquid Hydrogen (LH2)	~20,000
Ammonia (NH3)	~13,000

Note: Assumes a turbine efficiency of 35% (~44,500 MWh storage requirement).

14.4 Pricing

The cost of hydrogen purchased from a third party depends on many factors such as local supplier and producer availability, local hydrogen demand, local fuel policies, and potential purchase agreements between the supplier and the buyer. Although there are studies done in the province on potential hydrogen production, there are no current green hydrogen suppliers or production plants in Newfoundland and Labrador, making it very difficult and expensive to purchase from a third party.

Aside from the lack of supply chain, the amount of hydrogen required is also relatively large (100+ MW capacity), therefore it would likely require a dedicated production facility to ensure a constant supply of hydrogen.

Based on Hatch's experience, most clients requiring large hydrogen capacities tend to go with one of the two options below:

1. The user decides to build, operate, and own a hydrogen production facility for themselves. The cost associated with this option would be the CAPEX and OPEX shown above under Section 14.2.
2. The user decides to partner with a hydrogen supplier/producer. In this case, the supplier would build, operate, and own the production facility, but the hydrogen produced is sold to the using party through a contract on agreed cost for a period.

If purchasing hydrogen is of significant interest to NL Hydro, then Hatch would suggest NL Hydro to engage with industrial gas suppliers and producers in Newfoundland and Labrador to understand their plans for the province and the requirements for a green hydrogen supply chain in the province.

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Appendix A:
Heat and Mass Balance

PRELIMINARY ENERGY AND MASS BALANCE

Design assumptions:

Fuel: Diesel No 2, LHV – 18400 BTU/lb *Unit MW Size:* 50-70 MW

Site conditions : 15C/60 RH/ 152m 20C/81RH/152m

Table 1: Estimated performance

OEM	Units	GE		SIEMENS		MHI	
Model		LM6000 PC Sprint		SGT 800		FT 4000	
No of Units		4		4		2	
Site Condition	°C	15	20	15	20	15	20
Gross Output	MW	196	187	208	201	141	134
Heat Rate (LHV)	Btu/kWh	8633	8689	8712	8788	8335	8401
Water Injection per GT	GPM	43.4	39.4	-	-	69.2	64.2
Exhaust Temperature	°C	453	458	548	553	409	430
NOx	PPM	42				74	

Fuel: Biodiesel, LHV – 16400 BTU/lb *Unit MW Size:* 50-70 MW

Site conditions : 15C/60 RH/ 152m 20C/81RH/152m

Table 2: Estimated performance

OEM	Units	GE		SIEMENS		MHI	
Model		LM6000 PC Sprint		SGT 800		FT 4000	
No of Units		4		4		2	
Site Condition	°C	15	20	15	20	15	20
Gross Output	MW	195	187	-	-	-	-
Heat Rate (LHV)	Btu/kWh	8807	8843	-	-	-	-
Water Injection per GT	GPM	43.4	39.4	-	-	-	-
Exhaust Temperature	°C	455	459	-	-	-	-
NOx	PPM	42				-	

GE LM6000PC Sprint - Estimated Performance Sweep

SITE CONDITIONS	**Units**	**Case 1**	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**	**Case 7**	**Case 8**	**Case 9**	**Case 10**	**Case 11**	**Case 12**	**Case 13**	**Case 14**	**Case 15**	**Case 16**
Used Input File Addendum		No	No	No	No	No	No	No	No	No	No	No	No	No	No	No	No
Elevation	ft	499	499	499	499	499	499	499	499	499	499	499	499	499	499	499	499
Pressure	psia	14.433	14.433	14.433	14.433	14.433	14.433	14.433	14.433	14.433	14.433	14.433	14.433	14.433	14.433	14.433	14.433
Ambient Temperature	deg F	-40	-30	-20	-10	0	10	20	30	40	50	60	70	80	90	100	104
Humidity	%	60	60	60	60	60	60	60	60	60	60	60	60	60	51.64	42	36
Inlet Pressure Loss	in H2O	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Exhaust Pressure Loss	in H2O	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Generator Coolant		Air	Air	Air	Air	Air	Air	Air	Air	Air	Air	Air	Air	Air	Air	Air	Air
Power Factor (lag)		0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85

ESTIMATED PERFORMANCE	Units	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	Case 10	Case 11	Case 12	Case 13	Case 14	Case 15	Case 16
Load Condition	%	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Evap. Cooler Status		Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	On	On	On	On	On	On
Evap. Cooler Effectiveness	%											0.85	0.85	0.85	0.85	0.85	0.85
Fuel Type		Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate	Distillate
Fuel LHV	BTU/lb	18400	18400	18400	18400	18400	18400	18400	18400	18400	18400	18400	18400	18400	18400	18400	18400
Fuel Temperature	deg F	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Output at Generator Terminals	kW	49551	50451	50695	50786	50866	50550	50437	50820	49954	49424	48793	47236	45570	44135	42601	42364
Rated Heat Rate (LHV)	BTU/kWh	8341	8359	8375	8394	8417	8437	8481	8538	8581	8627	8637	8678	8725	8774	8838	8849
Heat Cons. (LHV)	MMBTU/hr	413.3	421.7	424.6	426.3	428.2	426.5	427.8	433.9	428.6	426.4	421.4	409.9	397.6	387.3	376.5	374.9
Exhaust Flow	x10^3 lb/hr	1163	1153	1145	1138	1132	1124	1112	1100	1076	1060	1048	1023	997	975	951	947
Exhaust Temperature	deg F	706	733	750	764	778	788	806	825	842	846	849	855	862	868	875	876
LPC Sprint Water Flow	GPM	0	0	0	0	0	0	0	0	0	17.3	17.89	18.75	18.43	18	17.62	17.56
HPC Sprint Water Flow	GPM	0	0	0	0	0	0	0	7.46	7.46	0	0	0	0	0	0	0

EMISSIONS	Units	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	Case 10	Case 11	Case 12	Case 13	Case 14	Case 15	Case 16
NOx	ppmvd @ 15	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
CO	ppmvd	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1
UHC	ppmvd	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
UHC	lb/hr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Exhaust Loss under Site Conditions are at ISO Conditions unless otherwise stated.
Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction. NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.
Distillate Fuel is assumed to have the specified percent Fuel-Bound Nitrogen or less.
FBN amounts greater than the specified percent will add to the reported NOx value.
Note: Modified Wobbe Index (MWI) is calculated as LHV/(Spec Gravity*Temp)^0.5, in BTU/scf/°R^0.5

Note: SCF is defined at 14.7 psi and 59°F

User: 204047135
Simulation Frame: LM6000-PCSPRINT-C-0620-L3
Date/Time: 10/7/22 3:43 PM
GTP Web v5.69.4, 2022

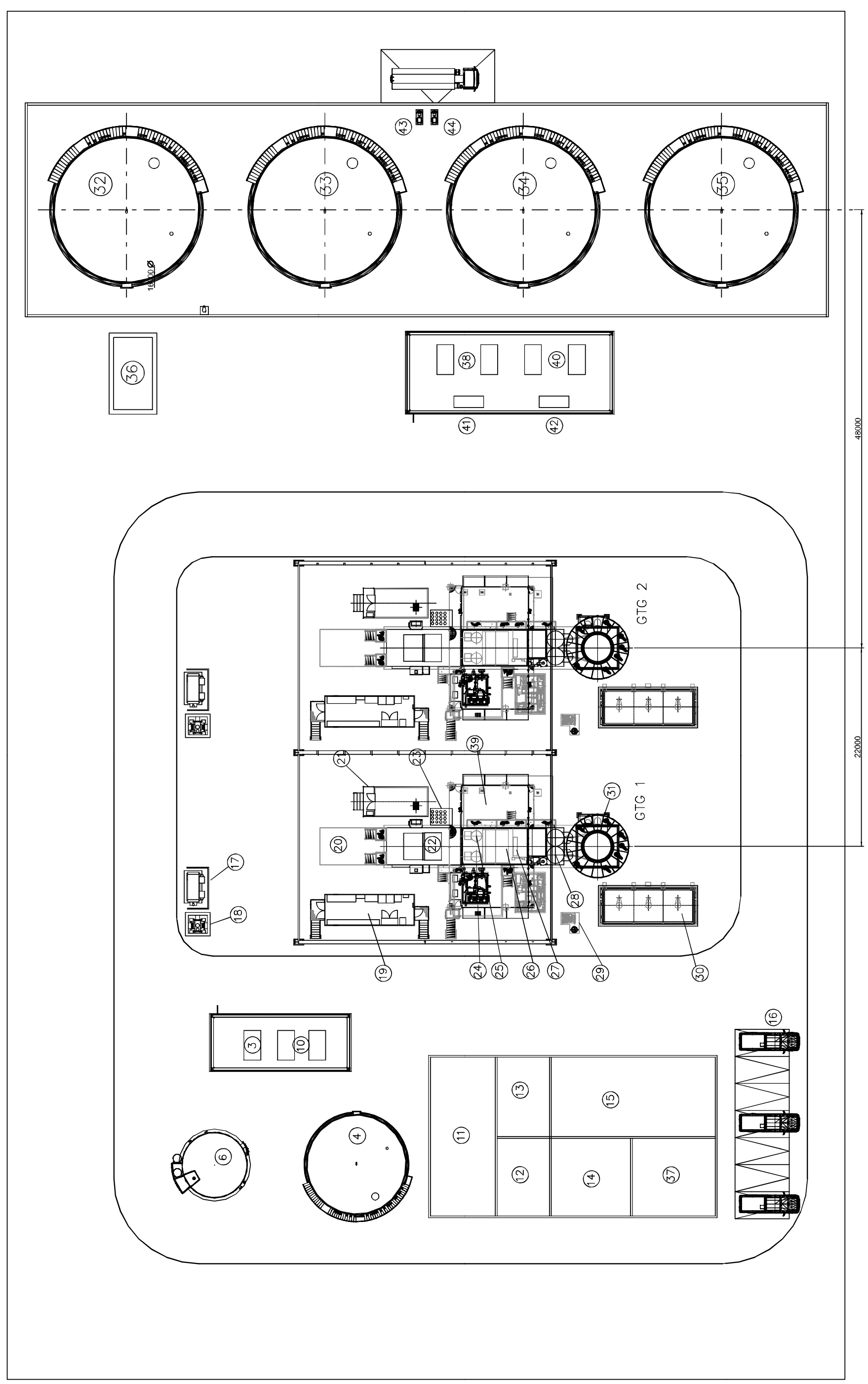
Appendix B:
Plant Layout

Appendix B1: 2 Unit Combustion Turbine – Brownfield

ITEM LEGEND

ITEM NO.	DESCRIPTION
1	-
2	-
3	RAW WATER PUMP SKID
4	RAW WATER STORAGE TANK
5	-
6	DEMIN WATER STORAGE 2
10	DEMIN WATER PUMP SKID
11	WATER TREATMENT PLANT
12	COMPRESSORS
13	BOP SWITCHGEAR
14	ADMIN
15	WORKSHOP AND STORE
16	PARKING
17	TRANSFORMER
18	AUXILIARY TRANSFORMER
19	MCC
20	GENERATOR REMOVAL AREA
21	11KV GENERATOR TERMINAL BUILDING
22	EXHAUST GENERATOR VENTILATION
23	FIRE CONTROL SKID
24	GEN FAN A
25	GEN FAN B
26	TURBINE COMBUSTION AIR
27	VBV DUCT
28	TURBINE FAN
29	SPRINT SKID
30	FINFAN COOLER
31	EXHAUST STACK
32	BIOFUEL TANK
33	DIESEL FUEL TANK
34	DIESEL FUEL TANK
35	DIESEL FUEL TANK
36	BLACK START DIESEL GENERATOR
37	CONTROL ROOM
38	BIOFUEL PUMP SKID
39	TURBINE AND GEARBOX REMOVAL AREA
40	FUEL PUMP SKID
41	COALESCING FILTERS AND HEATING SET
42	COALESCING FILTERS AND HEATING SET
43	FUEL UNLOADING PUMP
44	FUEL UNLOADING PUMP

NOTES
1. DIMENSIONS IN MILLIMETERS.



NEWFOUNDLAND AND LABRADOR HYDRO POWER PLANT LAYOUT- 2 UNITS

HATCH

No.	DESCRIPTION	BY	CHK'D	DATE
C	ISSUED FOR INFORMATION ONLY	MR	KM	14OCT2022
B	ISSUED FOR INFORMATION ONLY	FO	OO	29JUL2022
A	ISSUED FOR INFORMATION ONLY	FO	OO	25JUL2022

REVISIONS

ROLE	NAME	SIGNATURE	DATE
DRAFTSPERSON	M RAMOS	NR	14OCT22
DESIGNER	F OROJLOU	NR	14OCT22
CHECKER	O OWOLABI		
DESIGN COORD.	K MEGHARI		
RESP. ENG.			
LEAD DISC. ENG.			
ENG. MANAGER			
PROJ. MANAGER	K MEGHARI		

DRAWING APPROVAL STATUS: Client Review

REG. PROFESSIONAL

REFERENCE DRAWINGS | DRAWING TITLE | DRAWING No.

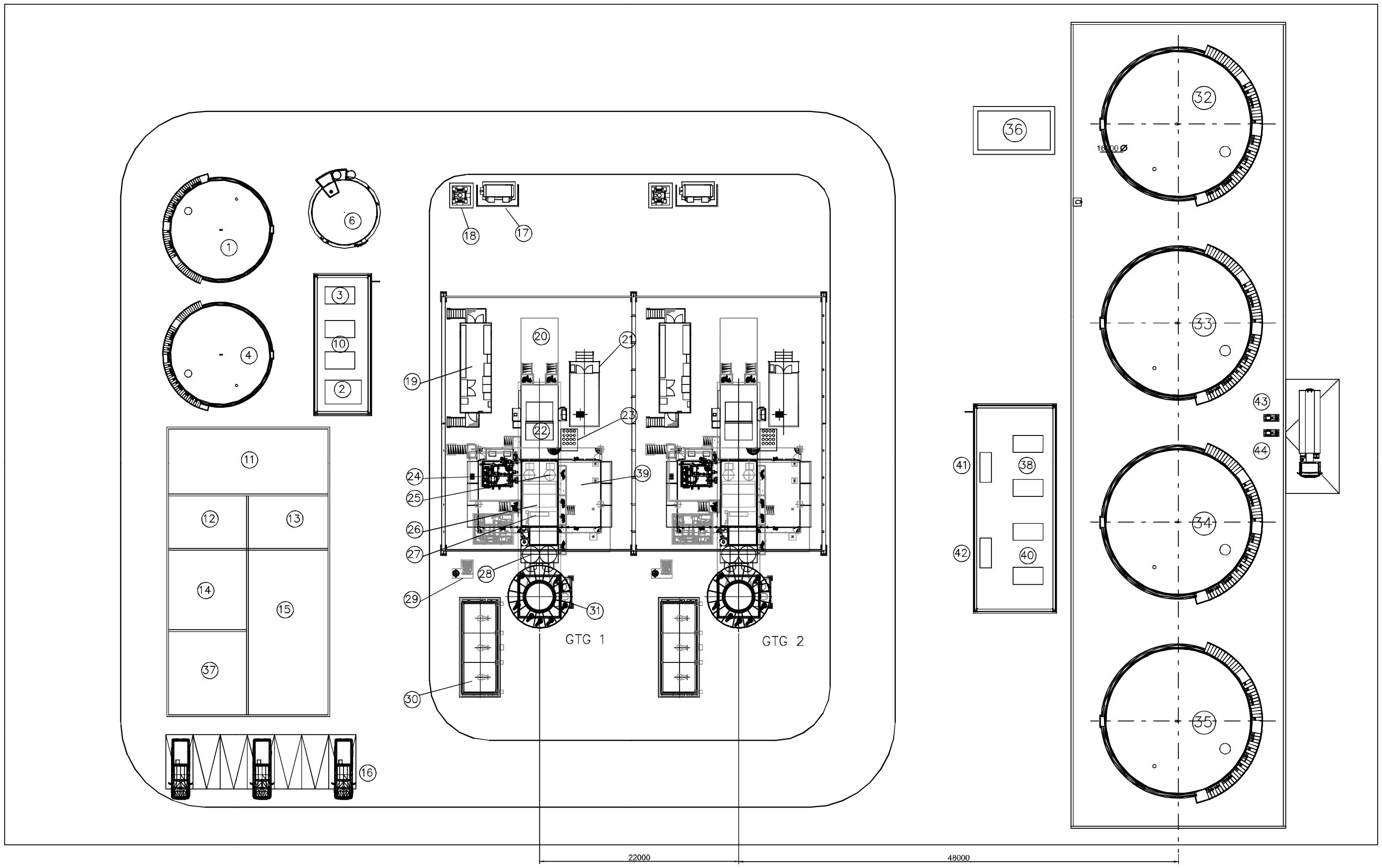
NEW FOUNDLAND AND LABRADOR HYDRO PROJECT

NLH POWER PLANT PRELIMINARY GENERAL ARRANGEMENT PLAN

SCALE 1"=60'-0" | DWG. No. H369039-3000-210-200-0002 | REV C

DWG. No. H369039-3000-210-200-0002

Appendix B2:
2 Unit Combustion Turbine – Greenfield



ITEM LEGEND

ITEM NO.	DESCRIPTION
1	FIRE WATER STORAGE
2	FIRE PUMP SKID
3	RAW WATER PUMP SKID
4	RAW WATER STORAGE TANK
5	–
6	DEMIN WATER STORAGE 2
10	DEMIN WATER PUMP SKID
11	WATER TREATMENT PLANT
12	COMPRESSORS
13	BOP SWITCHGEAR
14	ADMIN
15	WORKSHOP AND STORE
16	PARKING
17	TRANSFORMER
18	AUXILIARY TRANSFORMER
19	MCC
20	GENERATOR REMOVAL AREA
21	11KV GENERATOR TERMINAL BUILDING
22	EXHAUST GENERATOR VENTILATION
23	FIRE CONTROL SKID
24	GEN FAN A
25	GEN FAN B
26	TURBINE COMBUSTION AIR
27	VBV DUCT
28	TURBINE FAN
29	SPRINT SKID
30	FINFAN COOLER
31	EXHAUST STACK
32	BIOFUEL TANK
33	DIESEL FUEL TANK
34	DIESEL FUEL TANK
35	DIESEL FUEL TANK
36	BLACK START DIESEL GENERATOR
37	CONTROL ROOM
38	BIOFUEL PUMP SKID
39	TURBINE AND GEARBOX REMOVAL AREA
40	FUEL PUMP SKID
41	COALESCING FILTERS AND HEATING SET
42	COALESCING FILTERS AND HEATING SET
43	FUEL UNLOADING PUMP
44	FUEL UNLOADING PUMP

NOTES
1. DIMENSIONS IN MILLIMETERS.

NEWFOUNDLAND AND LABRADOR HYDRO POWER PLANT LAYOUT- 2 UNITS

No.	DESCRIPTION	BY	CHK'D	DATE
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B	ISSUED FOR INFORMATION ONLY	FO	OO	05OCT2022
A	ISSUED FOR INFORMATION ONLY	FO	OO	25JUL2022

REVISIONS

DRAWING No.	DRAWING TITLE

REFERENCE DRAWINGS

REG. PROFESSIONAL

HATCH

ROLE	NAME	SIGNATURE	DATE
DRAFTSPERSON	M RAMOS	NR	25AUG22
DESIGNER	F OROJLOU	NR	25AUG22
CHECKER	O OWOLABI		
DESIGN COORD.	K MEGHARI		
RESP. ENG.			
LEAD DISC. ENG.			
ENG. MANAGER			
PROJ. MANAGER	K MEGHARI		

DRAWING APPROVAL STATUS: Client Review

NEW FOUNDLAND AND LABRADOR HYDRO PROJECT

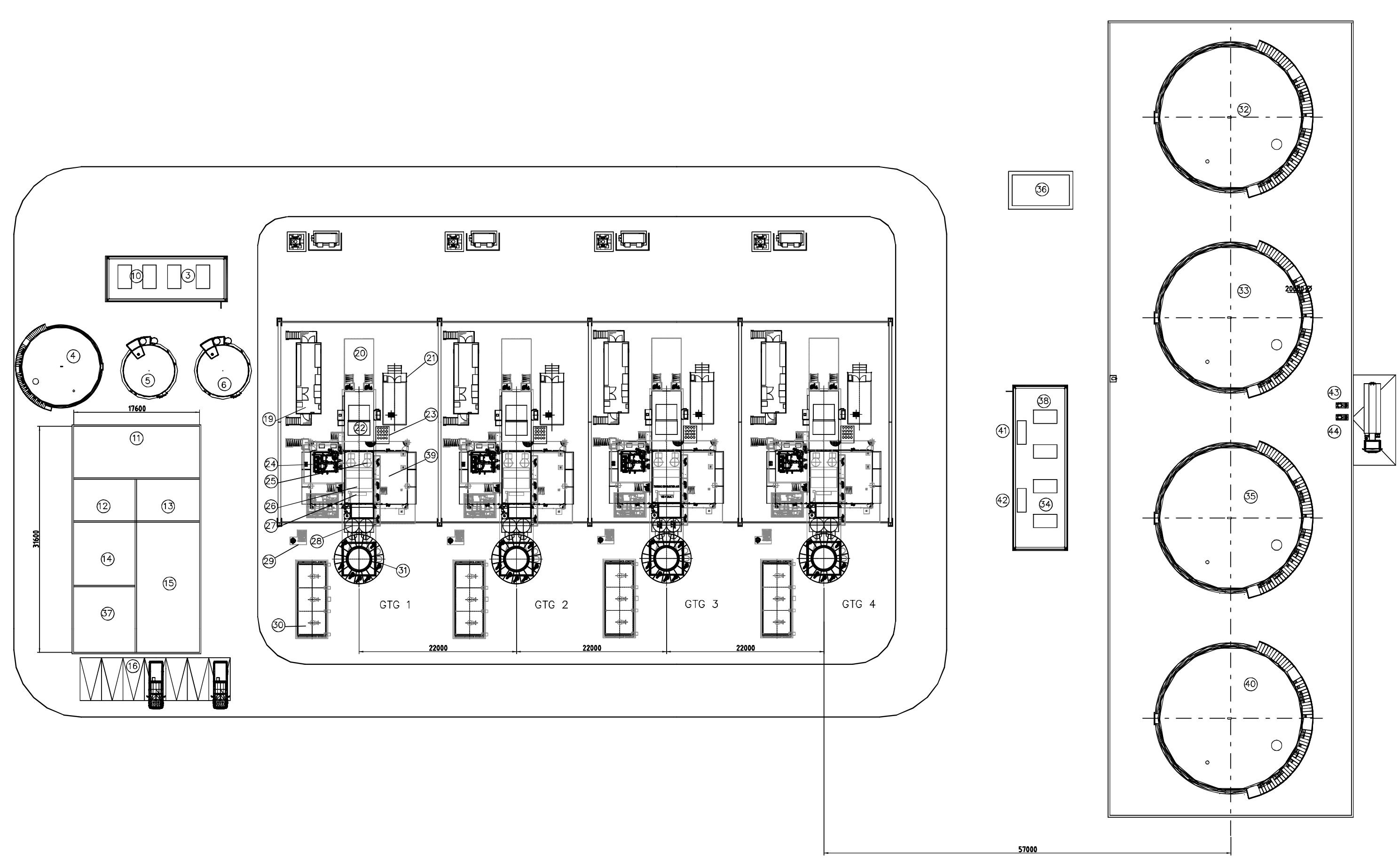
NLH POWER PLANT
PRELIMINARY GENERAL ARRANGEMENT PLAN

SCALE: 1"=60'-0" OR AS NOTED
DWG. No. H369039-3000-210-200-0002
REV C
SHEET SIZE: D

DWG. No. H369039-3000-210-200-0002

$USERNAME$ $DATE$ $FILE$ $TIME$

Appendix B3:
4 Unit Combustion Turbine – Brownfield



ITEM LEGEND

ITEM NO.	DESCRIPTION
1	–
2	–
3	RAW WATER PUMP SKID
4	RAW WATER STORAGE
5	DEMIN WATER STORAGE 1
6	DEMIN WATER STORAGE 2
10	DEMIN WATER PUMP SKID
11	WATER TREATMENT PLANT
12	COMPRESSORS
13	BOP SWITCHGEAR
14	ADMIN
15	WORKSHOP AND STORE
16	PARKING
17	TRANSFORMER
18	AUXILIARY TRANSFORMER
19	MCC
20	GENERATOR REMOVAL AREA
21	11KV GENERATOR TERMINAL BUILDING
22	EXHAUST GENERATOR VENTILATION
23	FIRE CONTROL SKID
24	GEN FAN A
25	GEN FAN B
26	TURBINE COMBUSTION AIR
27	VBV DUCT
28	TURBINE FAN
29	SPRINT SKID
30	FINFAN COOLER
31	EXHAUST STACK
32	BIOFUEL TANK
33	DIESEL FUEL TANK
34	FUEL PUMP SKID
35	DIESEL FUEL TANK
36	BLACK START DIESEL GENERATOR
37	CONTROL ROOM
38	BIOFUEL PUMP SKID
39	TURBINE AND GEARBOX REMOVAL AREA
40	DIESEL FUEL TANK
41	COALESCING FILTERS AND HEATING SET
42	COALESCING FILTERS AND HEATING SET
43	FUEL UNLOADING PUMP
44	FUEL UNLOADING PUMP

NOTES
1. DIMENSIONS IN MILLIMETERS.

DWG. No. H369039-3000-210-200-0001

NEWFOUNDLAND AND LABRADOR HYDRO POWER PLANT LAYOUT- 4 UNITS

No.	DESCRIPTION	BY	CHK'D	DATE
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B	ISSUED FOR INFORMATION ONLY	FO	OO	29JUL2022
A	ISSUED FOR INFORMATION ONLY	FO	OO	25JUL2022

REVISIONS

DRAWING No.	DRAWING TITLE

REFERENCE DRAWINGS

REG. PROFESSIONAL

HATCH

ROLE	NAME	SIGNATURE	DATE
DRAFTSPERSON	M RAMOS	NR	14OCT2022
DESIGNER	F OROJLOU	NR	14OCT2022
CHECKER	O OWOLABI		
DESIGN COORD.	K MEGHARI		
RESP. ENG.			
LEAD DISC. ENG.			
ENG. MANAGER			
PROJ. MANAGER	K MEGHARI		

DRAWING APPROVAL STATUS: Client Review

NEW FOUNDLAND AND LABRADOR HYDRO PROJECT

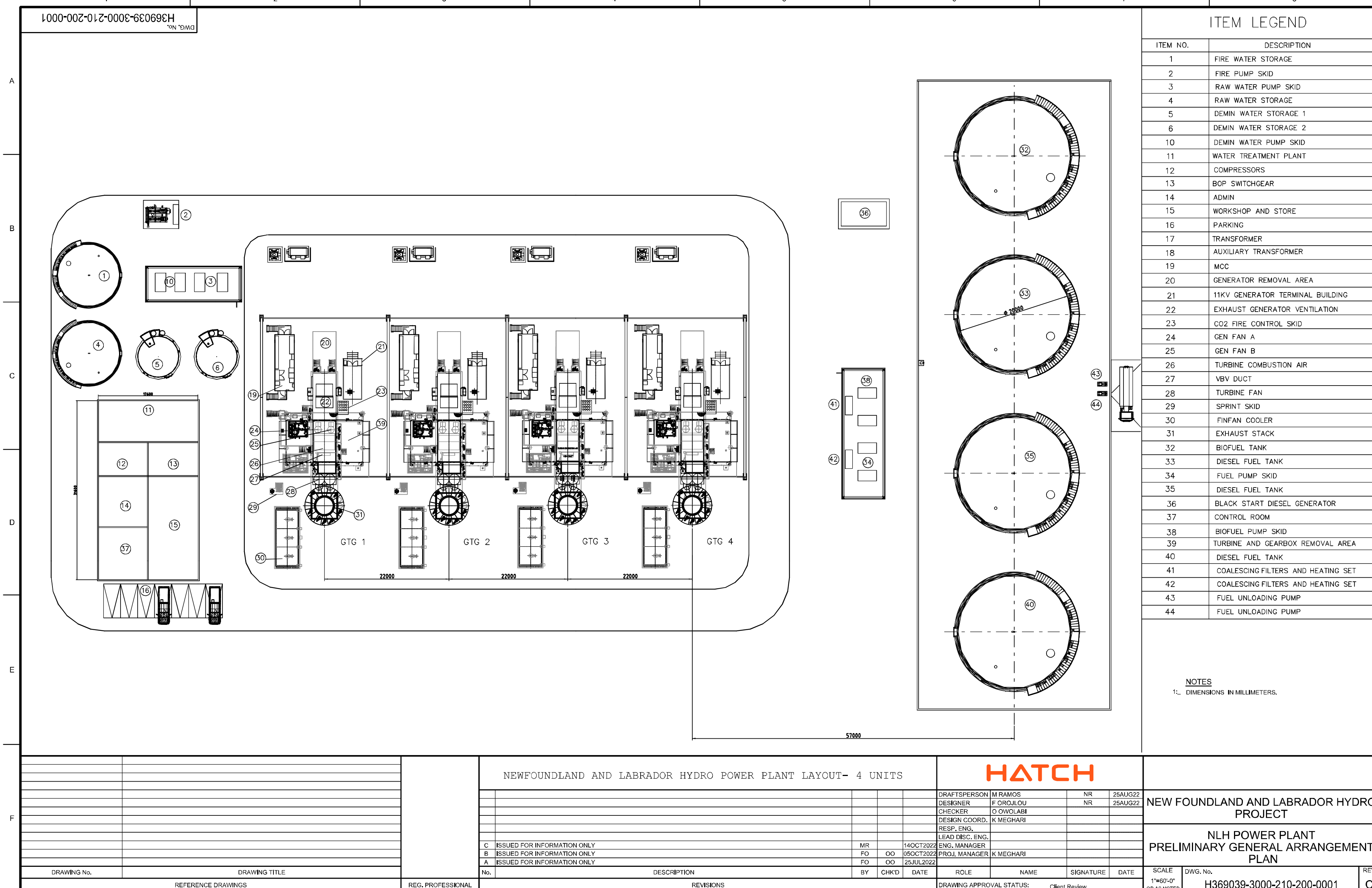
NLH POWER PLANT
PRELIMINARY GENERAL ARRANGEMENT PLAN

SCALE 1"=60'-0" OR AS NOTED | DWG. No. H369039-3000-210-200-0001 | REV C

SHEET SIZE: D

$USERNAME$ $DATE$ $FILE$ $TIME$

Appendix B4:
4 Unit Combustion Turbine – Greenfield


ITEM LEGEND
ITEM NO. DESCRIPTION
1 FIRE WATER STORAGE
2 FIRE PUMP SKID
3 RAW WATER PUMP SKID
4 RAW WATER STORAGE
5 DEMIN WATER STORAGE 1
6 DEMIN WATER STORAGE 2
10 DEMIN WATER PUMP SKID
11 WATER TREATMENT PLANT
12 COMPRESSORS
13 BOP SWITCHGEAR
14 ADMIN
15 WORKSHOP AND STORE
16 PARKING
17 TRANSFORMER
18 AUXILIARY TRANSFORMER
19 MCC
20 GENERATOR REMOVAL AREA
21 11KV GENERATOR TERMINAL BUILDING
22 EXHAUST GENERATOR VENTILATION
23 CO2 FIRE CONTROL SKID
24 GEN FAN A
25 GEN FAN B
26 TURBINE COMBUSTION AIR
27 VBV DUCT
28 TURBINE FAN
29 SPRINT SKID
30 FINFAN COOLER
31 EXHAUST STACK
32 BIOFUEL TANK
33 DIESEL FUEL TANK
34 FUEL PUMP SKID
35 DIESEL FUEL TANK
36 BLACK START DIESEL GENERATOR
37 CONTROL ROOM
38 BIOFUEL PUMP SKID
39 TURBINE AND GEARBOX REMOVAL AREA
40 DIESEL FUEL TANK
41 COALESCING FILTERS AND HEATING SET
42 COALESCING FILTERS AND HEATING SET
43 FUEL UNLOADING PUMP
44 FUEL UNLOADING PUMP
NOTES
1. DIMENSIONS IN MILLIMETERS.
GTG 1
GTG 2
GTG 3
GTG 4
22000
22000
22000
57000
NEWFOUNDLAND AND LABRADOR HYDRO POWER PLANT LAYOUT- 4 UNITS
HATCH
DRAFTSPERSON M RAMOS NR 25AUG22
DESIGNER F OROJLOU NR 25AUG22
CHECKER O OWOLABI
DESIGN COORD. K MEGHARI
RESP. ENG.
LEAD DISC. ENG.
ENG. MANAGER
PROJ. MANAGER K MEGHARI
ROLE NAME SIGNATURE DATE
DRAWING APPROVAL STATUS: Client Review
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B ISSUED FOR INFORMATION ONLY FO OO 05OCT2022
A ISSUED FOR INFORMATION ONLY FO OO 25JUL2022
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DRAWING No. DRAWING TITLE
REFERENCE DRAWINGS
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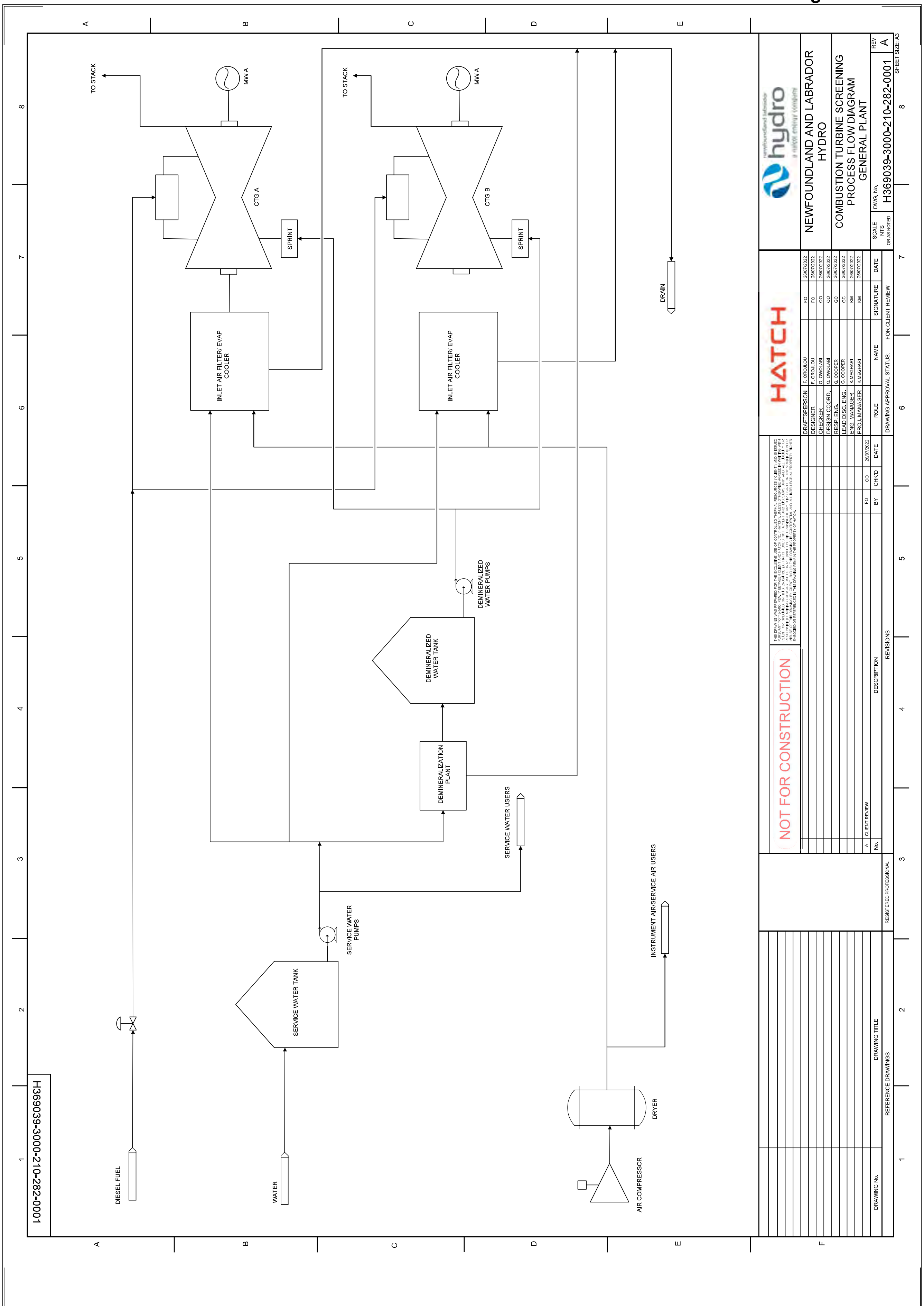
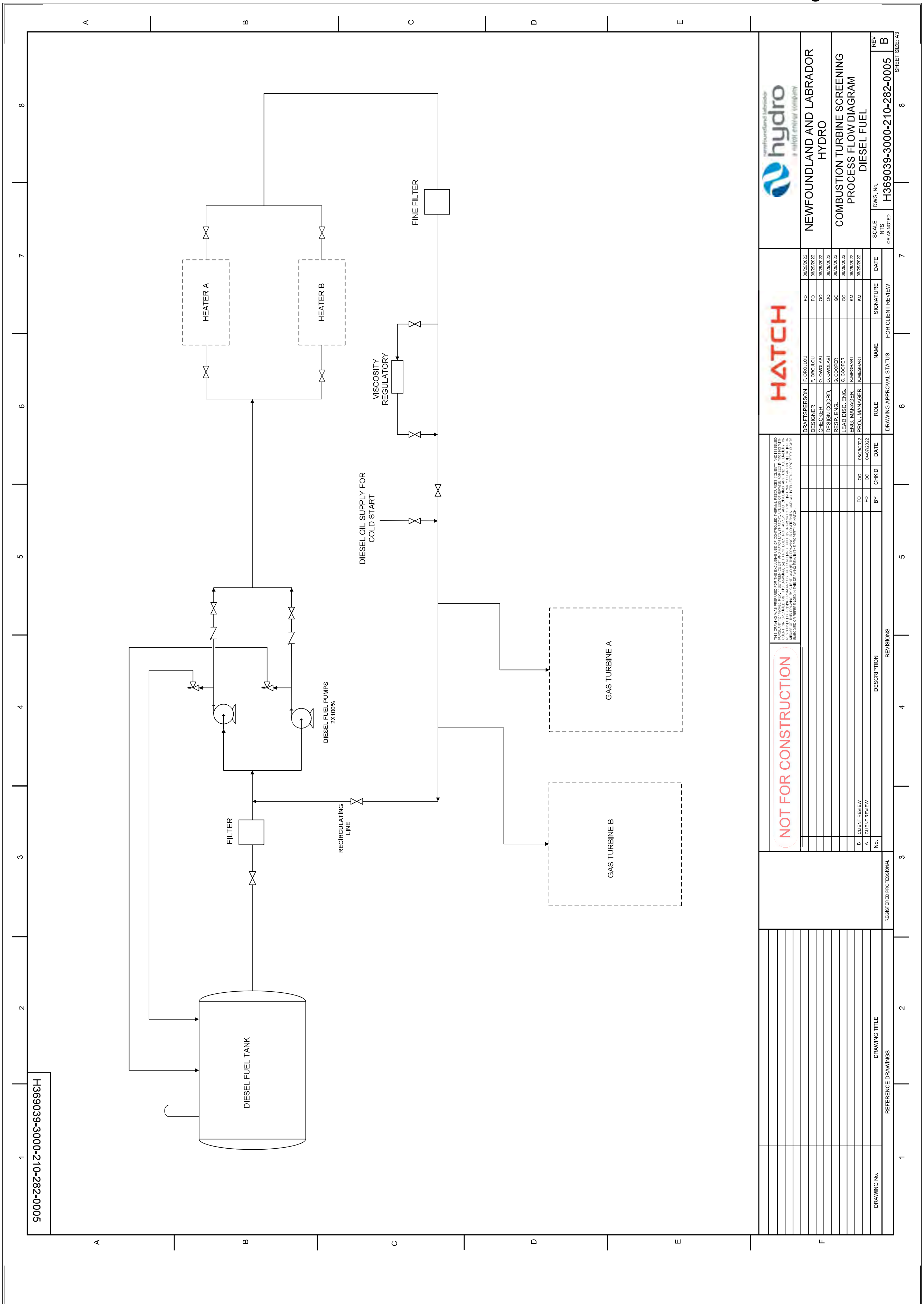
NEW FOUNDLAND AND LABRADOR HYDRO PROJECT
NLH POWER PLANT PRELIMINARY GENERAL ARRANGEMENT PLAN
SCALE 1"=60'-0" OR AS NOTED
DWG. No. H369039-3000-210-200-0001
REV C
SHEET SIZE: D
DWG. No. H369039-3000-210-200-0001

Appendix C:
Process Flow Diagrams

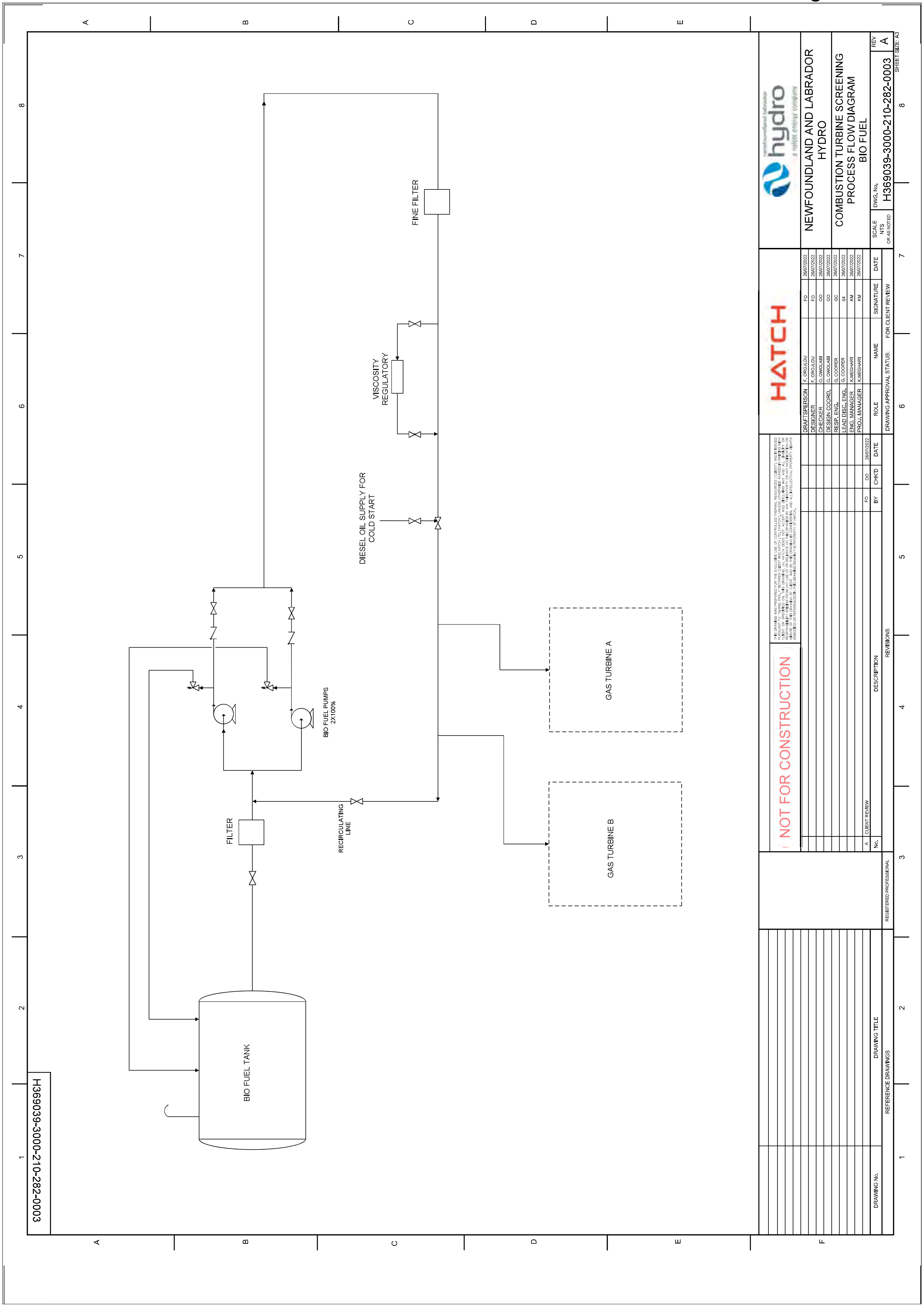
Appendix C1:
General PFD


TO STACK
MW A
CTG A
SPRINT
INLET AIR FILTER/ EVAP COOLER
TO STACK
MW A
CTG B
SPRINT
INLET AIR FILTER/ EVAP COOLER
DRAIN
DEMINERALIZED WATER PUMPS
DEMINERALIZED WATER TANK
DEMINERALIZATION PLANT
SERVICE WATER USERS
SERVICE WATER PUMPS
SERVICE WATER TANK
INSTRUMENT AIR/SERVICE AIR USERS
DIESEL FUEL
WATER
DRYER
AIR COMPRESSOR
H369039-3000-210-282-0001
HATCH
NOT FOR CONSTRUCTION
hydro
NEWFOUNDLAND AND LABRADOR HYDRO
COMBUSTION TURBINE SCREENING PROCESS FLOW DIAGRAM GENERAL PLANT
SCALE NTS
DWG. No. H369039-3000-210-282-0001
REV A
DRAFTSPERSON F. OROJLOU
DESIGNER F. OROJLOU
CHECKER O. OWOLABI
DESIGN COORD. O. OWOLABI
RESP. ENG. G. COOPER
LEAD DISC. ENG. G. COOPER
ENG. MANAGER K.MESHARI
PROJ. MANAGER K.MESHARI
DRAWING APPROVAL STATUS: FOR CLIENT REVIEW
A CLIENT REVIEW FO OO 26/07/2022
No. DESCRIPTION BY CHK'D DATE
REVISIONS
REGISTERED PROFESSIONAL
DRAWING No. DRAWING TITLE
REFERENCE DRAWINGS

Appendix C2:
Diesel PFD


DIESEL FUEL TANK
FILTER
RECIRCULATING LINE
DIESEL FUEL PUMPS 2X100%
HEATER A
HEATER B
VISCOSITY REGULATORY
DIESEL OIL SUPPLY FOR COLD START
FINE FILTER
GAS TURBINE A
GAS TURBINE B
NOT FOR CONSTRUCTION
NEWFOUNDLAND AND LABRADOR HYDRO
COMBUSTION TURBINE SCREENING
PROCESS FLOW DIAGRAM
DIESEL FUEL
H369039-3000-210-282-0005
B

Appendix C3:
Biofuel PFD


FINE FILTER
VISCOSITY REGULATORY
DIESEL OIL SUPPLY FOR COLD START
BIO FUEL PUMPS 2X100%
FILTER
RECIRCULATING LINE
GAS TURBINE A
GAS TURBINE B
BIO FUEL TANK
H369039-3000-210-282-0003
NOT FOR CONSTRUCTION
HATCH
NEWFOUNDLAND AND LABRADOR HYDRO
COMBUSTION TURBINE SCREENING
PROCESS FLOW DIAGRAM
BIO FUEL
DRAFTSPERSON F. OROJLOU FO 26/07/2022
DESIGNER F. OROJLOU FO 26/07/2022
CHECKER O. OWOLABI OO 26/07/2022
DESIGN COORD. O. OWOLABI OO 26/07/2022
RESP. ENG. G. COOPER GC 26/07/2022
LEAD DISC. ENG. G. COOPER 04 26/07/2022
ENG. MANAGER K.MEGHARI KM 26/07/2022
PROJ. MANAGER K.MEGHARI KM 26/07/2022
ROLE NAME SIGNATURE DATE
DRAWING APPROVAL STATUS: FOR CLIENT REVIEW
SCALE NTS OR AS NOTED
DWG. No. H369039-3000-210-282-0003
REV A
SHEET SIZE: A3
A CLIENT REVIEW FO OO 26/07/2022
No. DESCRIPTION BY CHK'D DATE
REVISIONS
REGISTERED PROFESSIONAL
DRAWING No. DRAWING TITLE
REFERENCE DRAWINGS

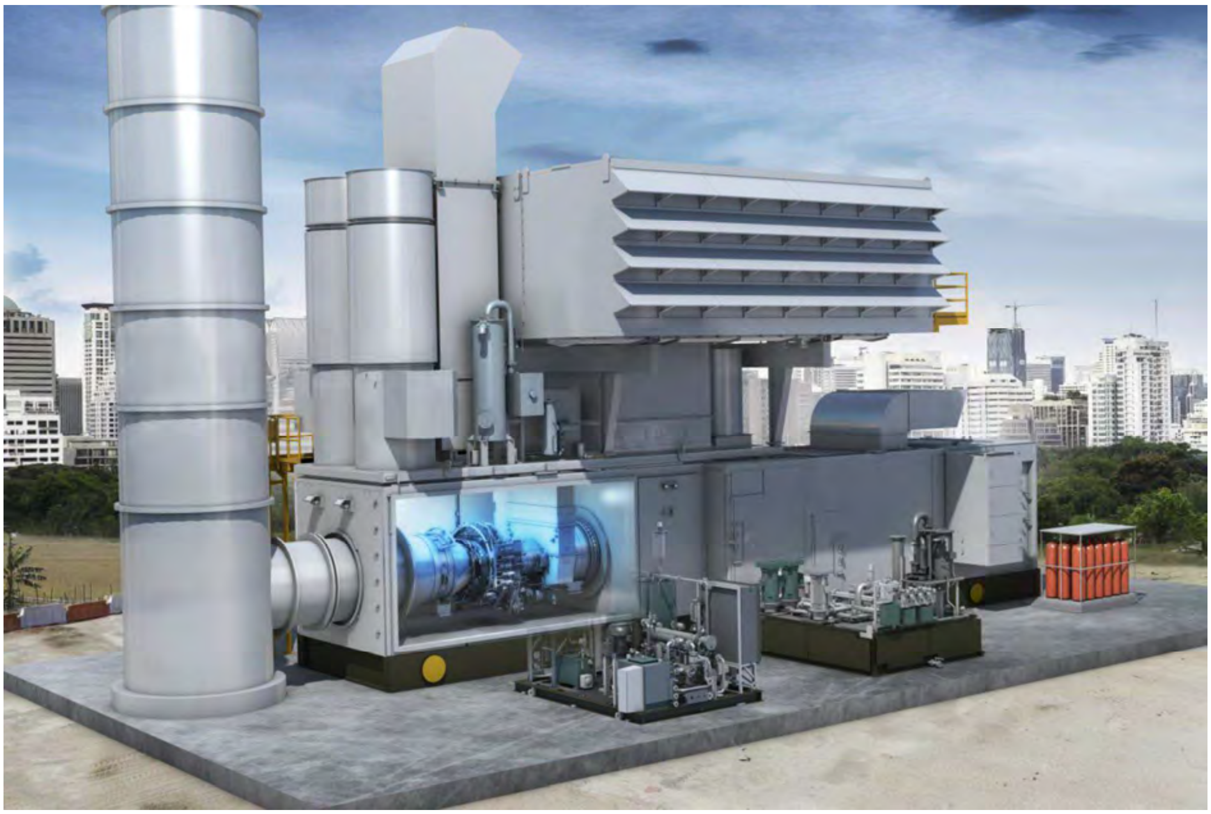
Appendix D:
Budgetary Cost

Appendix D1:
GE – LM6000

GE Power

BUDGETARY PROPOSAL

LM6000 Gas Turbine Generator Equipment



From GENERAL ELECTRIC

[Applicable Legal GE Entity(ies) to be defined at firm bid stage if any]

To HATCH ENGINEERING

Project: NL Peaking Project

Opportunity/Quote n°: 1616913 / CPQ-10748

Date: July 11, 2022

GE Power

1 - Introduction

The GE legal entity or entities providing you with this Budgetary Proposal are part of the GE Power division of General Electric. GE Power division is also referred to as "GE" in this Budgetary Proposal.

GE Power is one of the world's leading suppliers of power generation and energy delivery technologies and offers the widest range of heavy-duty gas turbine, steam turbines & generator solutions, with Gas Turbine outputs ranging from 34 to 544 megawatts. GE turbines serve reliably and efficiently in a wide variety of applications for world-wide electric utilities, independent power producers, municipalities and industrial companies, from pure power generation to industrial cogeneration and district heating.

GE Power

GE Technology for your Project: LM6000PC

Engineered to cost effectively cycle multiple times per day, our LM6000 aeroderivative gas turbine is fast and flexible, meeting dispatch profiles with proven reliability. With more than 1,200 units shipped and 33 million combined operating hours, the LM6000 family has more operating experience than any other aeroderivative gas turbine greater than 40 MW. It leads the field with greater than 99.8 percent reliability and 98.4 percent availability.

For more details, contact your Sales Representative or consult our online product catalog at: https://www.ge.com/power/gas/catalogs

Please see our performance estimating tools at https://gtpweb.gepower.com/gtpweb/login.htm .

GE Power

2 - General Assumptions

We are pleased to submit this Budgetary Proposal based on the following assumptions:

Installation Country	CANADA
State / Province	Newfoundland and Labrador
Frequency	60HZ

3 - Our Solution to Your Project

We believe the following equipment will be a competitive solution for the development of your project:

a. Gas Turbine Generator Equipment

Gas Turbine	LM6000-PC UG3 60HZ
Gas Turbine Quantity	Two (2)
Installation Type	Simple Cycle (SC)
Combustion System	Single Annular Combustor (SAC)

Auxiliary Equipment

Gas Turbine Package

- CSA (Canada) Certification
- Gas Turbine enclosure
- Lubricating Oil and Hydraulic Oil Systems
- Lube Oil Cooler: Shell & Tube Cooler
- Lube Oil Piping and Reservoir
- Winterization to -29°C (-20°F)

Air Inlet System

- Multi-stage Static Air Filtration System
- Evaporative Cooling for improved performance

Exhaust

- Exhaust Collector and Flange

GE Power

- Simple Cycle Exhaust System with Expansion Joint & Anchor Bolts

Fuel System

- Dual Fuel System (Natural Gas / Distillate Fuel)
- Distillate Fuel Filtering & Forwarding Skid

Generator & Accessories

- Ventilated air-cooled generator and brushless excitation system

Digital Control System

- Turbine Control Panel (TCP)
- Generator Monitoring and Integrated Generator Protection System
- 24 V DC Battery and Charger System
- Human Machine Interface (HMI)
- Fire Protection System
- Vibration Monitor
- GTG Motor Control Center (CE)

Additional Scope included in this Estimate

- Gas Turbine Water Wash System
- Aerosol Fire Protection
- Static Package Test

d. Services

The following services are included to support project implementation:

- Shipment Terms: ExWorks (Including Boxing)
- Engineering and quality documentation
- Operation and Maintenance Manuals (in English language) in electronic format
- Installation and Commissioning Manual in hard copy and electronic format
- Remote Monitoring and Diagnostic Service during the equipment warranty period
- Equipment Training: Full Operation and Maintenance Training onsite for the GE Scope of Supply
- GE On-site representative to Witness gas turbine performance test
- Technical Advisory (TA) services during installation and commissioning are included based upon a Typical Project Schedule, at rates based upon sellers current Field Services Rate Sheet, plus travel and living expenses.
- GE Equipment Project Management

e. Optional Services Available

The following services are available to be quoted separately:

GE Power

- GE Equipment Delivery to Site
- GE Conduct Gas Turbine Performance Testing

f. Customer Scope

We have listed for your convenience those major scope items which have not been included as the basis of this Budgetary Proposal.
Some of these items listed herein could be quoted separately as needed and upon request.
This list is not exclusive and not limitative.

- Building and civil works, site facilities, and civil engineering design
- Support steelworks and hangers for the gas turbine ducting, silencing, and pipe work
- All inlet, exhaust, and ventilation ducting other than included in the scope of supply
- Drains and/or vent piping from the gas turbine package to a remote point
- Fuel storage, treatment and forwarding system
- Site grounding and lightning protection
- Power system studies
- Sensing and metering voltage transformers,
- Machine power transformers, and associated protection
- Grid failure detection equipment
- Off loading, transportation and storage
- Off skid cabling, and design of off skid cable routing
- Balance of plant controls and balance of plant & energy optimization controls
- Anchor bolts, embedments, and grouting (quoted separately)
- Distributed plant control and customer's remote control
- Field supervision (quoted separately)
- High voltage transformer(s), cables, and associated equipment; auxiliary power transformer
- Interconnecting piping, conduit, and wiring between equipment modules
- Plant utilities, including supply of compressed air, instrument air, or cooling water, and off skid piping
- Battery containment
- Lube oil measurement other than that defined in the scope of supply
- Additional lube oil breather ducting other than that defined in the scope of supply
- Fuel transfer pump
- Off skid fuel block and vent valves
- Fuel supply pipework beyond the scope of supply
- Generator controls other than that defined in the scope of supply
- Load sharing control
- Balance of plant controls
- Field Performance Testing
- Site Labor
- Ladders, Stairs, and Platforms for that may be required
- Fuel, fluids, and chemicals for the gas turbine generator set

GE Power

4 - Delivery Cycle

The units could be delivered in the following cycle (from Full Notice to Proceed to Ex-works Delivery):

GTG Unit 1: 14 months, subject to GE engine availability

This estimated schedule is subject to confirmation at the time of a firm technical and commercial offer.

5 - Price

Indicative Price for the Above Scope of Supply*	**USD 49,679,000**
Indicative Price for Delivery to Site, for the Above Scope of Supply (2 units)	**USD 2,350,000**
Indicative Duties Cost***	**Estimated $0**

*The above price

- Includes a Standard 12 Month GE Equipment Operations Warranty
- Assumes first Gas Turbine and Generator ExWorks delivery from GE Factory Hungary November 30, 2023
- Excludes any sales tax, VAT, duties, or any other similar taxes
- Is based on GE Standard Payment Terms: 10% Down, 65% Calendar Based, 20% at Shipment, 5% 30 days after Shipment.

* At the time of a firm proposal, GE equipment will be offered Subject to Prior Sale and subject to mutually acceptable inflation price adjustment at the time of order execution. GE proposes an escalation adjustment based on the Producer Price Index Commodity data for Metals and Metal Products (WPU10) as determined and published monthly by the Bureau of Labor Statistics of the U.S. Department of Labor.

** Estimated Delivery Price is based on recent historical delivery quotes, assuming Incoterm DAP delivery to unknown address, Newfoundland and Labrador, Canada. Delivery price is subject to change pending final scope selections, final sourcing decisions, final project schedule, final site address, and detailed route survey. GE can provide delivery for actual delivery cost plus 15%.

*** Duties Cost Estimate is based on historical duties costs and are subject to change pending final scope selections, final sourcing decisions, and changes in law. Duties costs will be confirmed at the time of a firm proposal, if any.

GE Power

6 - Terms and Conditions

This Budgetary Proposal is based on GE standard Terms and Conditions of Contract. Full GE Terms and Conditions would be submitted with our firm bid, if any.

7 - Disclaimer

This Budgetary Proposal is issued for budgetary and reference purposes only. This Budgetary Proposal is not binding upon the GE legal entity submitting this document and does not create any obligations on the part of such GE legal entity, including no obligation to provide a firm proposal. The recommended product or system design and budgetary pricing, as well as any other term or condition contained in this Budgetary Proposal, are subject to change, including, without limitation, as additional information comes to the attention of GE, or you refine your desired requirements.

The GE legal entity or entities submitting this document would be pleased to work closely with you to potentially develop a firm price proposal for this project upon your written request.

GE Power

8 - Confidentiality

This Budgetary Proposal including all attachments contains GE Proprietary Information and is for the use of HATCH ENGINEERING for the purposes of evaluating the power plant possibilities. These documents cannot be given to other parties without prior written approval from GE (or its affiliate submitting this document).

To the extent a non-disclosure agreement is in place between a GE legal entity and HATCH ENGINEERING in relation to the project for which such Budgetary Proposal has been issued, such non-disclosure agreement shall apply.

GE sincerely appreciates this opportunity to provide you with this budgetary information and is willing to discuss and assist you on your project.

Sincerely,

Russ Young
Sales Director
GE Power | Gas Power Systems

GE Power

ATTACHMENTS :

- Gas Pressure Requirements

Gas Pressure Requirements

	Gas Fuel pressure psig [MPaG]		
	Min	Nominal	Max
LM6000 PC	655 [4.52]	675 [4.65]	695 [4.79]

For full-load operation, the gaseous fuel must be supplied to the baseplate at 675 psig±20 (4,654 ±138 kPag). Gas fuel must meet the latest General Electric (GE) specification MID-TD-0000-1

Appendix D2:
Mitsubishi Power Aero – FT4000

BUDGETARY
FT4000® GAS TURBINE PROPOSAL

To: Hatch

For: Newfoundland Power Project

To Design and Supply
(1) 140MW FT4000® SWIFTPAC® Unit
EQUIPMENT ONLY

Bid date:
July 12, 2022

Prepared by: Brian Grosjean / Reed Lengel
Mitsubishi Power Aero LLC
Glastonbury, CT USA

Proposal #: 03022RL

Notifications

The attached documentation and information is being provided on condition of confidentiality. By accepting receipt of such documentation and information, Customer agrees (i) not to use such documentation or information except to evaluate Mitsubishi Power Aero LLC's proposal as contemplated by this communication, and (ii) not to disclose such documentation or information to any third parties.

Warning

This document contains technical data the export of which is or may be restricted by the Export Administration Act and the Export Administration Regulations (EAR), 15 C.F.R. parts 730-774. Diversion contrary to U.S. law is prohibited. The export, re-export, transfer or re-transfer of this technical data to any other company, entity, person, or destination, or for any use or purpose other than that for which the technical data was originally provided by Mitsubishi Power Aero LLC, is prohibited without prior written approval from Mitsubishi Power Aero LLC and authorization under applicable export control laws.

EAR Export Classification: ECCN EAR99

Note

- MOBILEPAC, FT4000, SWIFTPAC and FT8 are registered trademarks of Mitsubishi Power Aero LLC.
- All other company and product names may be trademarks and are the property of their respective owners.

Mitsubishi Power Aero LLC
628 Hebron Avenue, Suite 400
Glastonbury, CT 06033 USA
aero.power.mhi.com

COMMERCIAL SECTION

Budgetary Estimate

Hatch

Proposal Number: 03022RL

BASE EQUIPMENT	QTY	TOTAL ESTIMATE USD
FT4000® SWIFTPAC® 140 Natural Gas, Water Injection with Wet Compression, including 60' Exhaust Stack & TA Support. Delivered EXW, Mitsubishi Power Aero designated facilities, per INCOTERMS 2020.	1	**$53,036,000**
Per attached Scope of Supply 03022RL		

Estimate provided is based on the proposal Terms and Conditions contained herein. The parties must enter into a written agreement incorporating Mitsubishi Power Aero LLC, Standard Turbine Purchase Terms and Conditions. Any changes to the standard terms and conditions must be mutually agreed upon in writing and may impact estimate.

Equipment is subject to prior sale.

Pricing is based on 2022 delivery.

This is a budgetary estimate for informational purposes only and cannot be accepted to form a binding contract.

Submittal Date: 7/12/2022

Mitsubishi Power Aero LLC
628 Hebron Avenue, Suite 400
Glastonbury, CT 06033 USA
aero.power.mhi.com

Payment Schedule

Payments will be due in accordance with the Payment Schedule and with Article 3 of the Mitsubishi Power Aero LLC standard Turbine Purchase Agreement, attached in this Estimate.

20%	Upon contract signing date*
70%	Four (4) monthly equal payments (17.5%) prior to final shipment. ** (last payment is due one month prior to shipment)
10%	Upon successful Performance Test Completion, not to exceed 120 days after Delivery.

- * First payment is due net five (5) days after receipt of invoice. All remaining payments are due net 30 days after receipt of invoice.
- ** Payments will be invoiced on the 15th of each month.
- Deliveries are subject to prior sale.

All payments made after delivery of equipment are to be secured via a stand-by Letter of Credit, substantially in the form of Exhibit 14 of the Turbine Purchase Agreement.

Submittal Date: 7/12/2022

Contract Delivery Schedule

MITSUBISHI POWER

MILESTONE TASK	ESTIMATED DELIVERY DATE	NOTES:
Contract Agreement Signed	TBD	Schedule (including Commercial Operation Date) may shift based on date agreement signed.
FT4000® SWIFTPAC® 140 Power Island Delivery Date	October 2022	

Equipment availability is subject to prior sale.

Delivery is EXW (ExWorks) Mitsubishi Power Aero designated facilities, per INCOTERMS 2020.

Submittal Date: 7/12/2022

Mitsubishi Power Aero LLC
628 Hebron Avenue, Suite 400
Glastonbury, CT 06033 USA
aero.power.mhi.com

Appendix D3:
Siemens – SGT-800

SGT-800 (57MW) Gas Turbine Power Generation Package

Indicative Price: $19.01MM US

Scope of Supply Outline

- **SGT-800 Gas Turbine Engine –** a low weight industrial, modular concept Gas Turbine, with DLE combustion chamber, on a welded I-beam base frame for the GT driver unit. Cold End Drive
- **Combustion Air Intake System –** Two stage HEPA static air intake filter and silencer
- **Exhaust System –** Includes bellow and transition piece, Horizontal exhaust,
- **Gas Fuel and Ignition System –** For Natural Gas including on package fuel piping, control and shut-off valves, flow meters, external gas fuel unit with dual shut-off valves and filter
- **Lubricating Oil System –** ISO VG 46 mineral oil, stainless steel piping downstream of the duplex filter, breather system, and lube oil water cooler
- **Cooling Water System –** The liquid-cooled oil cooler is a plate heat exchanger type in 316L material. The cooler will be designed for the specific site conditions
- **Water Cooled AC Generator –** 13.8kV/60Hz. Concrete mounted, including Generator (MV) terminal enclosure, Excitation and AVR, Generator Protection Equipment, Synchronizing Equipment
- **Electric Start & Barring System –** Including start motor frequency converter
- **Compressor Washing System –** Nozzles upstream of gas turbine compressor, for high pressure compressor washing
- **Weatherproof Acoustic Enclosure –** For Gas Turbine & Auxiliaries for sound attenuation to 85dB(A) at 3 feet
- **Enclosure Ventilation System –** Including silencer, filters, 2x 100% fans and dampers
- **Electrical and control module –** Consisting of MCC, Auxiliary Power distribution including UPS, PCS7 turbine control for automatic start- up, operation and shut down, Operator Station – NERC CIP cybersecurity compliance
- **Fire Extinguishing System –** Fire detection and CO_2 extinguishing system in enclosed rack.
- **Ambient temperatures –** From -4ºF to +104ºF (-20 to 40°C)
- **Delivery –** FAS Norkoping, Sweden, 17 months
- *Due to uncertain political and security situation in the world, the price and delivery times stated only represent a best estimate as of the date. The Price and Delivery Times are therefore not binding and are subject to review and potential Adjustment*

Siemens Energy Industrial Gas Turbines

This information contain Siemens proprietary information, if you have received it by mistake, please notify us immediately and delete this information from your system.

SGT-800 (62MW) Gas Turbine Power Generation Package

Indicative Price: $20.69MM US

Scope of Supply Outline

- **SGT-800 Gas Turbine Engine –** a low weight industrial, modular concept Gas Turbine, with DLE combustion chamber, on a welded I-beam base frame for the GT driver unit. Cold End Drive
- **Combustion Air Intake System –** Two stage HEPA static air intake filter and silencer
- **Exhaust System –** Includes bellow and transition piece, Horizontal exhaust,
- **Gas Fuel and Ignition System –** For Natural Gas including on package fuel piping, control and shut-off valves, flow meters, external gas fuel unit with dual shut-off valves and filter
- **Lubricating Oil System –** ISO VG 46 mineral oil, stainless steel piping downstream of the duplex filter, breather system, and lube oil water cooler
- **Cooling Water System –** The liquid-cooled oil cooler is a plate heat exchanger type in 316L material. The cooler will be designed for the specific site conditions
- **Water Cooled AC Generator –** 13.8kV/60Hz. Concrete mounted, including Generator (MV) terminal enclosure, Excitation and AVR, Generator Protection Equipment, Synchronizing Equipment
- **Electric Start & Barring System –** Including start motor frequency converter
- **Compressor Washing System –** Nozzles upstream of gas turbine compressor, for high pressure compressor washing
- **Weatherproof Acoustic Enclosure –** For Gas Turbine & Auxiliaries for sound attenuation to 85dB(A) at 3 feet
- **Enclosure Ventilation System –** Including silencer, filters, 2x 100% fans and dampers
- **Electrical and control module –** Consisting of MCC, Auxiliary Power distribution including UPS, PCS7 turbine control for automatic start- up, operation and shut down, Operator Station – NERC CIP cybersecurity compliance
- **Fire Extinguishing System –** Fire detection and CO_2 extinguishing system in enclosed rack.
- **Ambient temperatures –** From -4ºF to +104ºF (-20 to 40°C)
- **Delivery –** FAS Norkoping, Sweden, 17 months
- *Due to uncertain political and security situation in the world, the price and delivery times stated only represent a best estimate as of the date. The Price and Delivery Times are therefore not binding and are subject to review and potential Adjustment*

Siemens Energy Industrial Gas Turbines

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Appendix E: Project Schedule

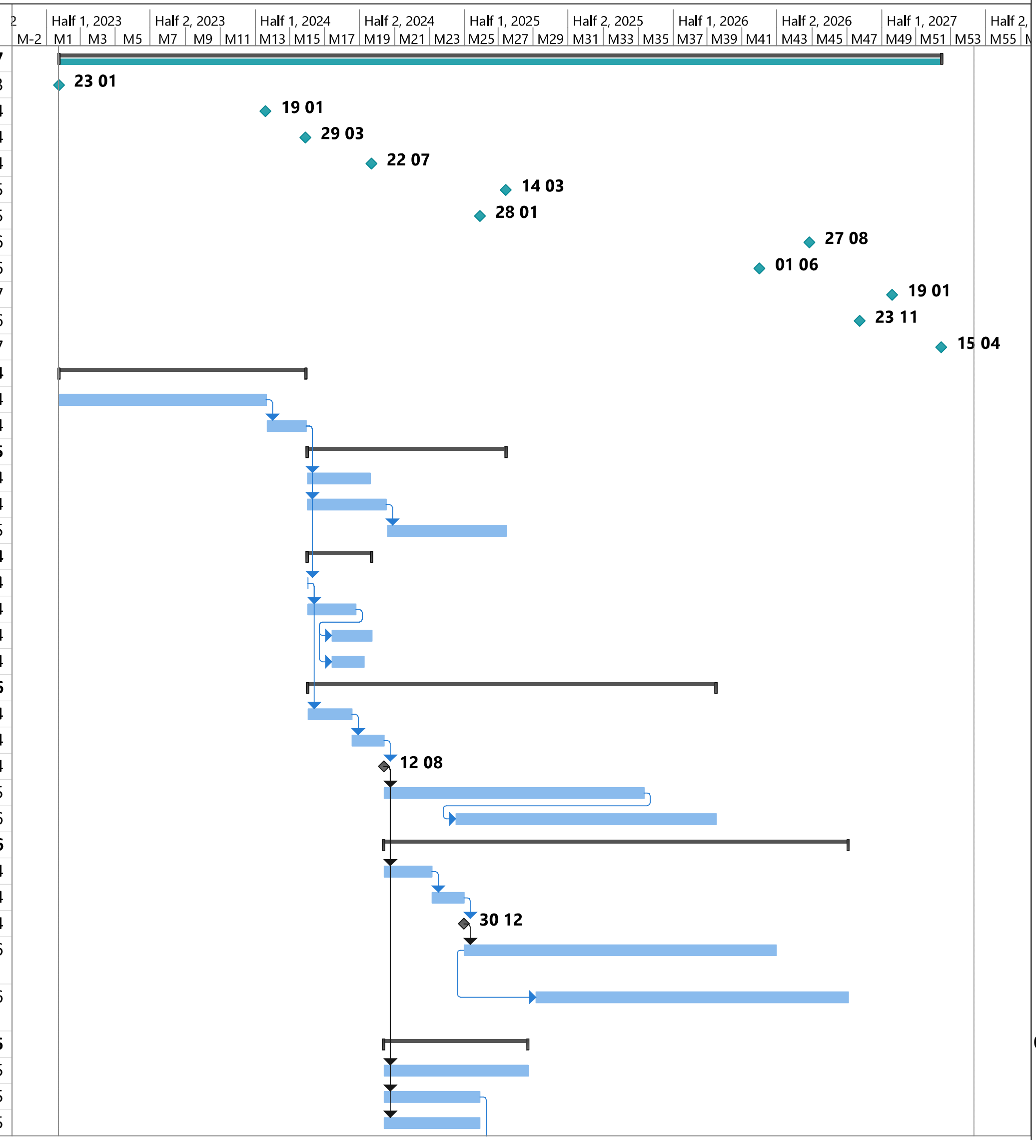
Appendix E1:
2 Unit Combustion Turbine Schedule

newfoundland labrador hydro

Newfoundland Labrador Hydro
Combustion Turbine Screening
Preliminary Schedule
H369039 -00000-200-076-001 Rev. B

HATCH

ID	Task Name	Duration	Start	Finish
1	**Key Milestones**	**1104 days**	**23 01 2023**	**15 04 2027**
2	NLH Budgeting and Approval Start	0 days	23 01 2023	23 01 2023
3	NLH Budgeting and Approval Complete	0 days	19 01 2024	19 01 2024
4	EPCM Contract Award	0 days	29 03 2024	29 03 2024
5	Preliminary Engineering Start	0 days	22 07 2024	22 07 2024
6	Enviromental Approval	0 days	14 03 2025	14 03 2025
7	Start of Construction (Per Owner RFP)	0 days	28 01 2025	28 01 2025
8	Mechanical Completion Unit #1	0 days	27 08 2026	27 08 2026
9	Site Utility Services Available	0 days	01 06 2026	01 06 2026
10	Mechanical Completion Unit #2	0 days	19 01 2027	19 01 2027
11	Commercial Operation Unit #1	0 days	23 11 2026	23 11 2026
12	Commercial Operation Unit #2	0 days	15 04 2027	15 04 2027
13	**Project Development**	**310 days**	**23 01 2023**	**29 03 2024**
14	NLH Budgeting and Approval	260 days	23 01 2023	19 01 2024
15	EPCM Contract Negotiations and Award	50 days	22 01 2024	29 03 2024
16	**Permitting / Approval Process**	**250 days**	**01 04 2024**	**14 03 2025**
17	Emission/Noise modelling report	80 days	01 04 2024	19 07 2024
18	Enviromental Application Process	100 days	01 04 2024	16 08 2024
19	Enviromental Approval	150 days	19 08 2024	14 03 2025
20	**Preliminary Engineering**	**81 days**	**01 04 2024**	**22 07 2024**
21	Project Kick off meeting	1 day	01 04 2024	01 04 2024
22	Design Basis & Preliminary P&ID's Layout / SLDs	60 days	02 04 2024	24 06 2024
23	Preliminary Specs for Long Lead Equipment	50 days	14 05 2024	22 07 2024
24	Prepare Cost Estimate	40 days	14 05 2024	08 07 2024
25	**Gas Turbine Generator (GTG) Procurement**	**510 days**	**02 04 2024**	**16 03 2026**
26	Specifications and RFQ's	55 days	02 04 2024	17 06 2024
27	Bids, Evaluations & Clarifications	40 days	18 06 2024	12 08 2024
28	Supply Contract Award	0 days	12 08 2024	12 08 2024
29	GTG #1 Design / Manufacturing and Delivery on Site	325 days	13 08 2024	10 11 2025
30	GTG #2 Design / Manufacturing and Delivery on Site	325 days	17 12 2024	16 03 2026
31	**GSU Transformers Procurement**	**580 days**	**13 08 2024**	**02 11 2026**
32	Specifications and RFQ's	60 days	13 08 2024	04 11 2024
33	Bids, Evaluations & Clarifications	40 days	05 11 2024	30 12 2024
34	Contract Award	0 days	30 12 2024	30 12 2024
35	GSU #1 Transformer Design / Manufacturing and Delivery on Site	390 days	31 12 2024	29 06 2026
36	GSU #2 Transformer Design / Manufacturing and Delivery on Site	390 days	06 05 2025	02 11 2026
37	**Detailed Engineering**	**180 days**	**13 08 2024**	**21 04 2025**
38	Detailed Engineering	180 days	13 08 2024	21 04 2025
39	Civil & Found. Works Contract Spec's/ Bid Process/ Award	120 days	13 08 2024	27 01 2025
40	Mech & Elec Installation Contract RFP/Bid Proces/Award	120 days	13 08 2024	27 01 2025

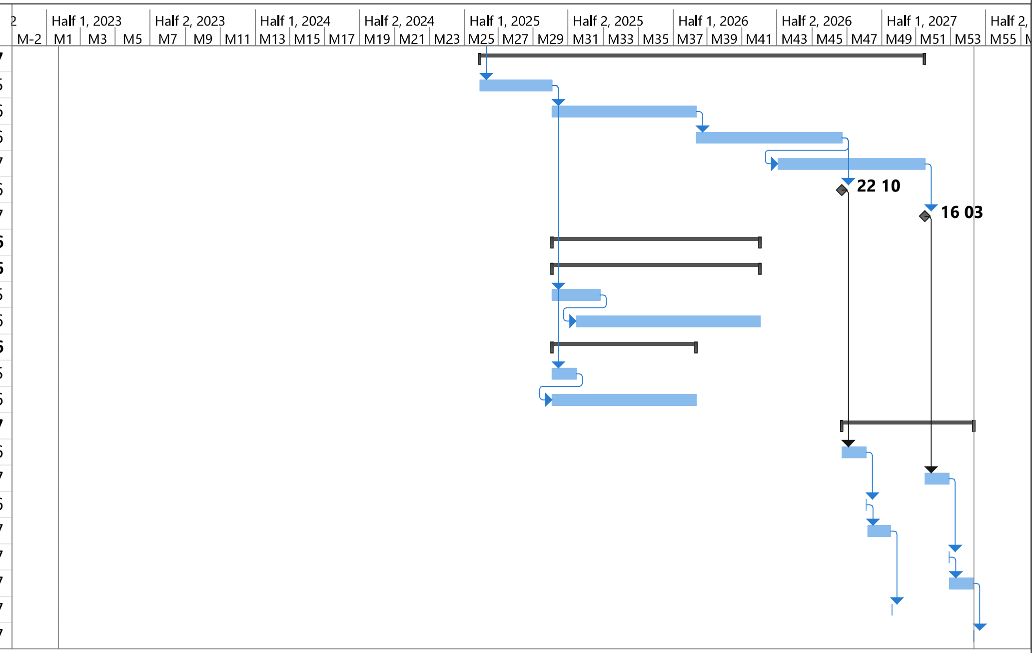


newfoundland labrador hydro

Newfoundland Labrador Hydro
Combustion Turbine Screening
Preliminary Schedule
H369039 -00000-200-076-001 Rev. B

HATCH

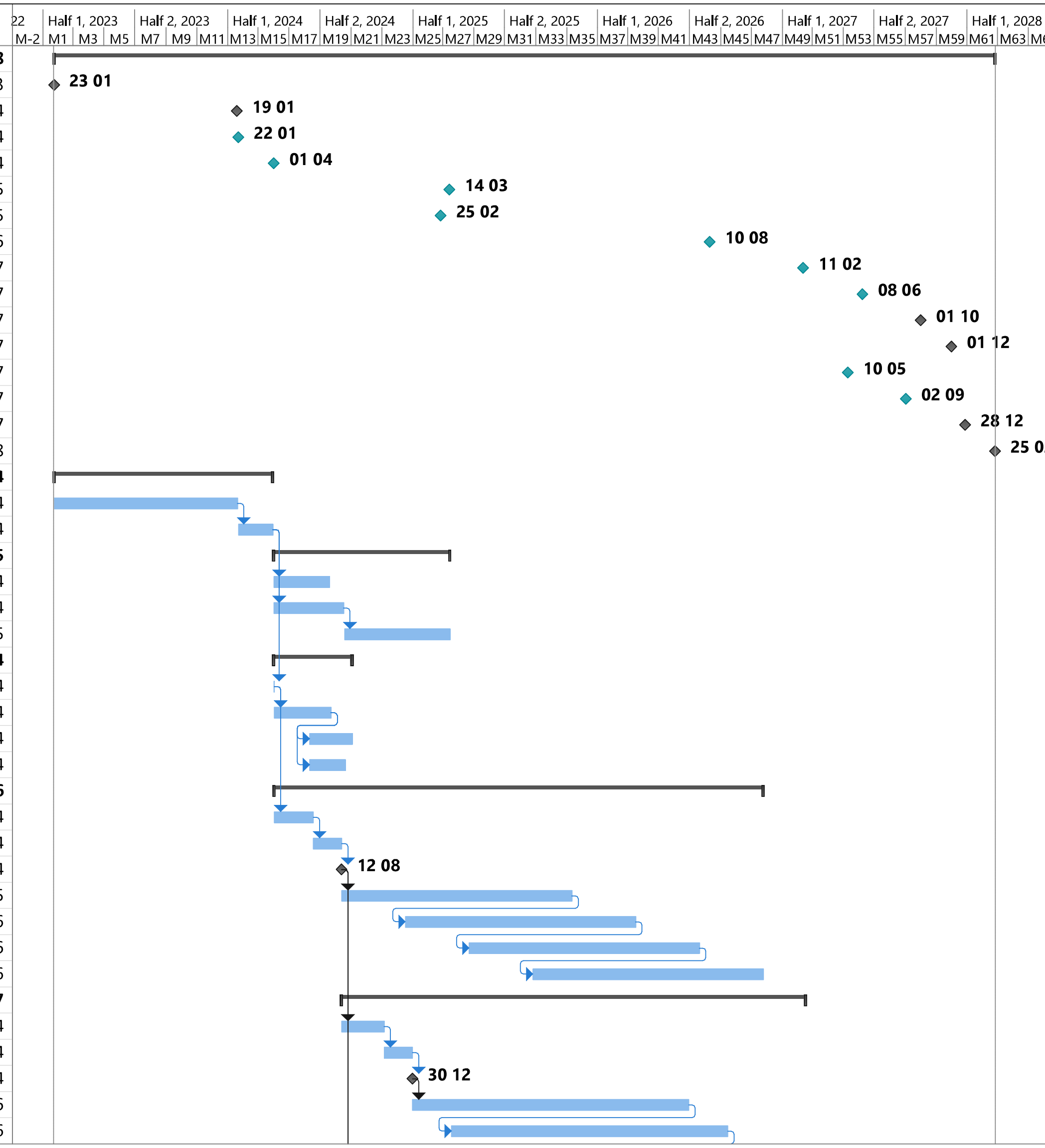
ID	Task Name	Duration	Start	Finish
41	**Construction**	**556 days**	**28 01 2025**	**16 03 2027**
42	Site Grading / Roads / Drainage	90 days	28 01 2025	02 06 2025
43	Piling / Found. / Buildings	180 days	03 06 2025	09 02 2026
44	GTG #1 Installation Work Execution	183 days	10 02 2026	22 10 2026
45	GTG #2 Installation Work Execution	183 days	03 07 2026	16 03 2027
46	Mechanical Completion Unit #1	0 days	22 10 2026	22 10 2026
47	Mechanical Completion Unit #2	0 days	16 03 2027	16 03 2027
48	**Serivices To Site**	**260 days**	**03 06 2025**	**01 06 2026**
49	**Transmission Line / HV Connection**	**260 days**	**03 06 2025**	**01 06 2026**
50	Preliminary Studies/Specs/Negotiations	60 days	03 06 2025	25 08 2025
51	Permitting Process & Approval	230 days	15 07 2025	01 06 2026
52	**Water Supply**	**180 days**	**03 06 2025**	**09 02 2026**
53	Preliminary Studies/Specs/Negotiations	30 days	03 06 2025	14 07 2025
54	Permitting Process & Approval	180 days	03 06 2025	09 02 2026
55	**Comissioning & Testing**	**165 days**	**23 10 2026**	**10 06 2027**
56	Check Out/PreComm Unit #1	30 days	23 10 2026	03 12 2026
57	Check Out/PreComm Unit #2	30 days	17 03 2027	27 04 2027
58	First Fire - Unit #1	1 day	04 12 2026	04 12 2026
59	Startup/Testing Including Performance Unit #1	30 days	07 12 2026	15 01 2027
60	First Fire - Unit #2	1 day	28 04 2027	28 04 2027
61	Startup/Testing Including Performance Unit #2	30 days	29 04 2027	09 06 2027
62	Commercial Operation Unit #1	1 day	18 01 2027	18 01 2027
63	Commercial Operation Unit #2	1 day	10 06 2027	10 06 2027



Appendix E2:
4 Unit Combustion Turbine Schedule

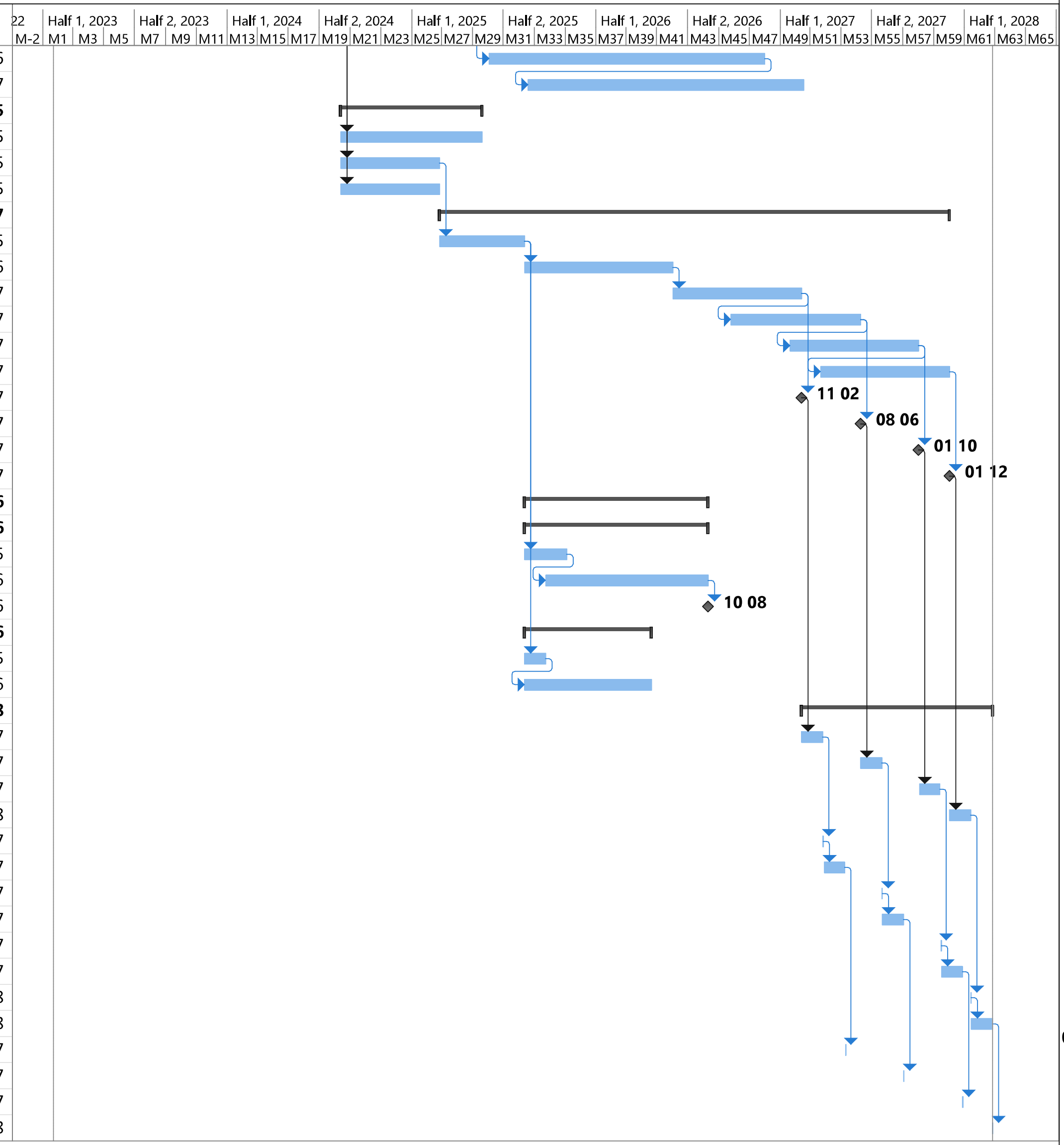
Newfoundland Labrador Hydro
Combustion Turbine Screening
Preliminary Schedule
H369039-00000-200-076-001 Rev. B

ID	Task Name	Duration	Start	Finish
1	**Key Milestones**	**1329 days**	**23 01 2023**	**25 02 2028**
2	NLH Budgeting and Approval Start	0 days	23 01 2023	23 01 2023
3	NLH Budgeting and Approval Complete	0 days	19 01 2024	19 01 2024
4	EPCM Contract Award	0 days	22 01 2024	22 01 2024
5	Preliminary Engineering Start	0 days	01 04 2024	01 04 2024
6	Enviromental Approval	0 days	14 03 2025	14 03 2025
7	Start of Construction (Per Owner RFP)	0 days	25 02 2025	25 02 2025
8	Site Utility Services Available	0 days	10 08 2026	10 08 2026
9	Mechanical Completion Unit #1	0 days	11 02 2027	11 02 2027
10	Mechanical Completion Unit #2	0 days	08 06 2027	08 06 2027
11	Mechanical Completion Unit #3	0 days	01 10 2027	01 10 2027
12	Mechanical Completion Unit #4	0 days	01 12 2027	01 12 2027
13	Commercial Operation Unit #1	0 days	10 05 2027	10 05 2027
14	Commercial Operation Unit #2	0 days	02 09 2027	02 09 2027
15	Commercial Operation Unit #3	0 days	28 12 2027	28 12 2027
16	Commercial Operation Unit #4	0 days	25 02 2028	25 02 2028
17	**Project Development**	**310 days**	**23 01 2023**	**29 03 2024**
18	NLH Budgeting and Approval	260 days	23 01 2023	19 01 2024
19	EPCM Contract Negotiations and Award	50 days	22 01 2024	29 03 2024
20	**Permitting / Approval Process**	**250 days**	**01 04 2024**	**14 03 2025**
21	Emission/Noise modelling report	80 days	01 04 2024	19 07 2024
22	Enviromental Application Process	100 days	01 04 2024	16 08 2024
23	Enviromental Approval	150 days	19 08 2024	14 03 2025
24	**Preliminary Engineering**	**111 days**	**01 04 2024**	**02 09 2024**
25	Project Kick off meeting	1 day	01 04 2024	01 04 2024
26	Design Basis & Preliminary P&ID's Layout / SLDs	80 days	02 04 2024	22 07 2024
27	Preliminary Specs for Long Lead Equipment	60 days	11 06 2024	02 09 2024
28	Prepare Cost Estimate	50 days	11 06 2024	19 08 2024
29	**Gas Turbine Generator (GTG) Procurement**	**690 days**	**02 04 2024**	**23 11 2026**
30	Specifications and RFQ's	55 days	02 04 2024	17 06 2024
31	Bids, Evaluations & Clarifications	40 days	18 06 2024	12 08 2024
32	Supply Contract Award	0 days	12 08 2024	12 08 2024
33	GTG #1 Design / Manufacturing and Delivery on Site	325 days	13 08 2024	10 11 2025
34	GTG #2 Design / Manufacturing and Delivery on Site	325 days	17 12 2024	16 03 2026
35	GTG #3 Design / Manufacturing and Delivery on Site	325 days	22 04 2025	20 07 2026
36	GTG #4 Design / Manufacturing and Delivery on Site	325 days	26 08 2025	23 11 2026
37	**GSU Transformers Procurement**	**655 days**	**13 08 2024**	**15 02 2027**
38	Specifications and RFQ's	60 days	13 08 2024	04 11 2024
39	Bids, Evaluations & Clarifications	40 days	05 11 2024	30 12 2024
40	Contract Award	0 days	30 12 2024	30 12 2024
41	GSU #1 Transformer Design / Manufacturing and Delivery on Sit	390 days	31 12 2024	29 06 2026
42	GSU #2 Transformer Design / Manufacturing and Delivery on Sit	390 days	18 03 2025	14 09 2026



Newfoundland Labrador Hydro
Combustion Turbine Screening
Preliminary Schedule
H369039-00000-200-076-001 Rev. B

ID	Task Name	Duration	Start	Finish
43	GSU #3 Transformer Design / Manufacturing and Delivery on Sit	390 days	03 06 2025	30 11 2026
44	GSU #4 Transformer Design / Manufacturing and Delivery on Sit	390 days	19 08 2025	15 02 2027
45	**Detailed Engineering**	**200 days**	**13 08 2024**	**19 05 2025**
46	Detailed Engineering	200 days	13 08 2024	19 05 2025
47	Civil & Found. Works Contract Spec's/ Bid Process/ Award	140 days	13 08 2024	24 02 2025
48	Mech & Elec Installation Contract RFP/Bid Proces/Award	140 days	13 08 2024	24 02 2025
49	**Construction**	**722 days**	**25 02 2025**	**01 12 2027**
50	Site Grading / Roads / Drainage	120 days	25 02 2025	11 08 2025
51	Piling / Found. / Buildings	210 days	12 08 2025	01 06 2026
52	GTG #1 Installation Work Execution	183 days	02 06 2026	11 02 2027
53	GTG #2 Installation Work Execution	183 days	25 09 2026	08 06 2027
54	GTG #3 Installation Work Execution	183 days	20 01 2027	01 10 2027
55	GTG #4 Installation Work Execution	183 days	22 03 2027	01 12 2027
56	Mechanical Completion Unit #1	0 days	11 02 2027	11 02 2027
57	Mechanical Completion Unit #2	0 days	08 06 2027	08 06 2027
58	Mechanical Completion Unit #3	0 days	01 10 2027	01 10 2027
59	Mechanical Completion Unit #4	0 days	01 12 2027	01 12 2027
60	**Serivices To Site**	**260 days**	**12 08 2025**	**10 08 2026**
61	**Transmission Line / HV Connection**	**260 days**	**12 08 2025**	**10 08 2026**
62	Preliminary Studies/Specs/Negotiations	60 days	12 08 2025	03 11 2025
63	Permitting Process & Approval	230 days	23 09 2025	10 08 2026
64	Site Utility Services Available	0 days	10 08 2026	10 08 2026
65	**Water Supply**	**180 days**	**12 08 2025**	**20 04 2026**
66	Preliminary Studies/Specs/Negotiations	30 days	12 08 2025	22 09 2025
67	Permitting Process & Approval	180 days	12 08 2025	20 04 2026
68	**Comissioning & Testing**	**271 days**	**12 02 2027**	**25 02 2028**
69	Check Out/PreComm Unit #1	30 days	12 02 2027	25 03 2027
70	Check Out/PreComm Unit #2	30 days	09 06 2027	20 07 2027
71	Check Out/PreComm Unit #3	30 days	04 10 2027	12 11 2027
72	Check Out/PreComm Unit #4	30 days	02 12 2027	12 01 2028
73	First Fire - Unit #1	1 day	26 03 2027	26 03 2027
74	Startup/Testing Including Performance Unit #1	30 days	29 03 2027	07 05 2027
75	First Fire - Unit #2	1 day	21 07 2027	21 07 2027
76	Startup/Testing Including Performance Unit #2	30 days	22 07 2027	01 09 2027
77	First Fire - Unit #3	1 day	15 11 2027	15 11 2027
78	Startup/Testing Including Performance Unit #3	30 days	16 11 2027	27 12 2027
79	First Fire - Unit #4	1 day	13 01 2028	13 01 2028
80	Startup/Testing Including Performance Unit #4	30 days	14 01 2028	24 02 2028
81	Commercial Operation Unit #1	1 day	10 05 2027	10 05 2027
82	Commercial Operation Unit #2	1 day	02 09 2027	02 09 2027
83	Commercial Operation Unit #3	1 day	28 12 2027	28 12 2027
84	Commercial Operation Unit #4	1 day	25 02 2028	25 02 2028



Appendix F:
Equipment List

Appendix F1:
2 Unit Combustion Turbine – Brownfield

HATCH

Equipment List

Originator:	**Date Submitted:**	**Project No.:**	**Revision:**
Hatch	10/26/2022	H-369039	C
Client:	**Project Name:**		**Discipline:**
Newfoundland and Labrador Hydro	Combustion Turbine Screening	Brown Field 2 units	Thermal Power
Document Number:	**Hatch Responsible Project Manager:**		Karim Meghari
H-369039-00000-200-216-004			
	Client Representative:		Ryan Cooper

WBS #	Description	Description of sub-components	Quantity	Duty % /Volume	Notes
Equipment List:					
10	**Gas Turbine Generator**	Gas Turbine Generator with Exhaust Door	2		
		Gas Turbine Fuel Module	2		
		Generator Breaker Enclosure			
		GT Electrical and Control Compartment	2		
		Exhaust Frame Blower	4		
		GT Coolling Water Module	2		
		Lube Oil Demister	2		
	Gas Turbine Firefighting Skid	Gas Turbine Firefighting Skid	1		Vortex / FM200
	Gas Turbine Wash Pakage	Gas Turbine Water Was Skid	1		
20	**Common Services Equipment and Systems**				
21	**Plant Water Systems (Common)**				
	Service Water System	Service Water Storage Tank	0		
		Service Water Pumps	0	100	
		Strainers	0	100	
		Piping/Hoses	Lot		
	2-Stage Reverse Osmosis(RO)	2 parallel trains		100	
		First Stage RO pumps	2	100	
		First Stage Membrane Units	2	100	
		Break Tank	1	100	
		Energy recovery devices	2	100	
		Caustic Soda Tote and Pump	1	100	
		Second Stage RO Pumps	2	100	
		Second Stage Membrane Units	2	100	
		RO Product Water Tank	1		
		RO Reject to CW Weir	Lot		
		Piping Valves, etc.	Lot		
		Clean-in-Place Skid (for membrane cleaning)	Lot		
	DI Water	RO Product Water Pumps	2	100	
		Electrodeionization (EDI) Units	2	100	
		DI Water Tank	1	500 m3	2 days Demin water storage for 2 GTs at 100% capacity
	Waste Water System	Wastewater Collection Sumps			
		Wastewater Collection Sump Pumps			
		Fuel Storage Sump			
		Fuel Storage Sump Pump			
		Dirty Water Sump			
		Dirty Water Sump Pump			
		Piping Systems			
		Oily Water Seperator			
		Waste Water Catch Basin			
		Sanitary Sewage System			
23	Compressed Air, Gas & Vacuum Systems				
	Plant Air & Instrument Air System	Air Compressors	0	100	Screw type Compressor. Two per GT
		Instrument Air Dryers	0	100	One per Unit. Regenerative or Desicant
		Service Air Receiver (per Unit)	0	100	Vertical
		Instrument Air Receiver (per Unit)	2	50	Vertical
		Piping & Valves	Lot		
24	Lubricating Oil Storage/treatment	Oil Cleaning Unit (per Unit)	1		
25	Emergency Diesel Generators	Emergency Diesel Generators	2		
26	Fire Protection Systems	Water Storage (Fire Water Tank)	1	1000 m3	2 hours Fire water storage
		Main Pump - electric	1	100	
		Emergency/backup Pump -diesel	1	100	
		Jockey Pump - electric	1	100	
		Water Ring Main System	Lot		
		Dry Deluge Spray System	Lot		
		Valved Fire Water Connections	Lot		
		Yard Hydrant & Hose Station	Lot		
		Wet System Sprinklers	Lot		
		Portable Dry Chemical Extinguishers	Lot		
		CO2 systams	Lot		
30	**Fuel Supply and Storage**				
31	Diesel Handling & Storage (Common)	Diesel Storage Tanks	2	2800 m3 each	7 days storage for 2 GTs operating at baseload (100% GT capacity)
		Fuel Metering	1		
		Interconnecting piping and piping to gas turbine	Lot		
		Fuel Supply to Diesel Generator		100	
		Fuel forwarding Pumps	2	100	
		Oil separator	2		
		Fuel heaters	2	100	Electric heaters
		Fuel offloading pump	2	100	
32	Biofuel	Biofuel Storage Tank	2	2800 m^3 each	7 days storage for 2 GT.
		Fuel Metering	1		
		Interconnecting piping and piping to gas turbine	Lot		
		Fuel Pumps	2	100	
		Fuel offloading pump	2	100	
40	**Miscellaneous Equipment & Systems**				
41	Workshop Equipment and Tools		Lot		
	Laboratory and Test Equipment		Lot		
50	**Environmental (Emissions) Control Systems (per Unit)**				
	Continuous Emission Monitoring (Unit)	One system for each flue	1		
60	**Electrical Power Systems**				
61	240-kV Main Power Output System (per Unit)	Main 11/240-kV Power Transformer (TP at HV	2		
		Generator Isolated-phase Bus System	Lot		
		Generator Circuit Breakers	2		
		Metering and Protection	Lot		
		Grounding System	Lot		
62	Auxiliary Power Supply system	11/4.16 kV Unit Auxiliary Transformer	2		
63	Unit/Station Power Supply system	4.16/0.6-kV Unit/Station Services Transformer	6		
		4.16 kV MV switchgear	Lot		
		600 V switchgear	Lot		
		600 V MCC's	Lot		
64	Auxiliary AC Power Distribution (Common)	Emergency Diesel Generator	1		
65	UPS Supply and Distribution (per Unit)	110-V, 1 ph, 50 Hz Power Distribution	Lot		
	DC Supply (Common)	125 VDC Supply and Distribution System	2		
66	Cabling Systems	Power, Control and Instrumentation	Lot		
67	Building and Outdoor Electrical Services		Lot		
	Grounding grid	Will be tied into existing plant grid.	Lot		
70	**Instrumentation and Control**				
71	Central Control System, incl. DCS		Lot		
72	Power generation & Auxiliaries I&C		Lot		
73	Common Sevices and equipment I&C		Lot		

Appendix F2:
2 Unit Combustion Turbine – Greenfield

HATCH

Equipment List

Originator:	Date Submitted:	Project No.:	Revision:
Hatch	10/26/2022	H-369039	C
Client:	**Project Name:**		**Discipline:**
Newfoundland and Labrador Hydro	Combustion Turbine Screening	Green Field 2 units	Thermal Power
Document Number:	**Hatch Responsible Project Manager:**		Karim Meghari
H-369039-00000-200-216-002			
	Client Representative:		Ryan Cooper

WBS #	Description	Description of sub-components	Quantity	Duty % /Volume	Notes
Equipment List:					
10	**Gas Turbine Generator**	Gas Turbine Generator with Exhaust Door	2		
		Gas Turbine Fuel Module	2		
		Generator Breaker Enclosure			
		GT Electrical and Control Compartment	2		
		Exhaust Frame Blower	4		
		GT Coolling Water Module	2		
		Lube Oil Demister	2		
	Gas Turbine Firefighting Skid	Gas Turbine Firefighting Skid	1		Vortex / FM200
	Gas Turbine Wash Pakage	Gas Turbine Water Was Skid	1		
20	**Common Services Equipment and Systems**				
21	**Plant Water Systems (Common)**				
	Service Water System	Service Water Storage Tank	1	1000 m^3	2 days water storage for 2 GTs at 100% capacity
		Service Water Pumps	2	100	
		Strainers	2	100	
		Piping/Hoses	Lot		
	2-Stage Reverse Osmosis(RO)	2 parallel trains		100	
		First Stage RO pumps	2	100	
		First Stage Membrane Units	2	100	
		Break Tank	1	100	
		Energy recovery devices	2	100	
		Caustic Soda Tote and Pump	1	100	
		Second Stage RO Pumps	2	100	
		Second Stage Membrane Units	2	100	
		RO Product Water Tank	1		
		RO Reject to CW Weir	Lot		
		Piping Valves, etc.	Lot		
		Clean-in-Place Skid (for membrane cleaning)	Lot		
	DI Water	RO Product Water Pumps	2	100	
		Electrodeionization (EDI) Units	2	100	
		DI Water Tank	1	500 m^3	2 days Demin water storage for 2 GTs at 100% capacity
	Waste Water System	Wastewater Collection Sumps			
		Wastewater Collection Sump Pumps			
		Fuel Storage Sump			
		Fuel Storage Sump Pump			
		Dirty Water Sump			
		Dirty Water Sump Pump			
		Piping Systems			
		Oily Water Seperator			
		Waste Water Catch Basin			
		Sanitary Sewage System			
23	Compressed Air, Gas & Vacuum Systems				
	Plant Air & Instrument Air System	Air Compressors	4	100	Screw type Compressor. Two per GT
		Instrument Air Dryers	2	100	One per Unit. Regenerative or Desicant
		Service Air Receiver (per Unit)	2	100	Vertical
		Instrument Air Receiver (per Unit)	2	50	Vertical
		Piping & Valves	Lot		
24	Lubricating Oil Storage/treatment	Oil Cleaning Unit (per Unit)	1		
25	Emergency Diesel Generators	Emergency Diesel Generators	2		
26	Fire Protection Systems	Water Storage (Fire Water Tank)	1	1000 m^3	2 hours Fire water storage
		Main Pump - electric	1	100	
		Emergency/backup Pump -diesel	1	100	
		Jockey Pump - electric	1	100	
		Water Ring Main System	Lot		
		Dry Deluge Spray System	Lot		
		Valved Fire Water Connections	Lot		
		Yard Hydrant & Hose Station	Lot		
		Wet System Sprinklers	Lot		
		Portable Dry Chemical Extinguishers	Lot		
		CO_2 systems	Lot		
30	**Fuel Supply and Storage**				
31	Diesel Handling & Storage (Common)	Diesel Storage Tanks	2	2800 m^3 each	7 days storage for 2 GTs operating at baseload (100% GT capacity)
		Fuel Metering	1		
		Interconnecting piping and piping to gas turbine	Lot		
		Fuel Supply to Diesel Generator		100	
		Fuel forwarding Pumps	2	100	
		Oil separator	2		
		Fuel heaters	2	100	Electric heaters
		Fuel offloading pump	2	100	
32	Biofuel	Biofuel Storage Tank	2	2800 m^3 each	7 days storage for 2 GT.
		Fuel Metering	1		
		Interconnecting piping and piping to gas turbine	Lot		
		Fuel Pumps	2	100	
		Fuel offloading pump	2	100	
40	**Miscellaneous Equipment & Systems**				
41	Workshop Equipment and Tools		Lot		
	Laboratory and Test Equipment		Lot		
50	**Environmental (Emissions) Control Systems (per Unit)**				
	Continuous Emission Monitoring (Unit)	One system for each flue	1		
60	**Electrical Power Systems**				
61	240-kV Main Power Output System (per Unit)	Main 11/240-kV Power Transformer (TP at HV Terminals	2		
		Generator Isolated-phase Bus System	Lot		
		Generator Circuit Breakers	2		
		Metering and Protection	Lot		
		Grounding System	Lot		
62	Auxiliary Power Supply system	11/4.16 kV Unit Auxiliary Transformer	2		
63	Unit/Station Power Supply system	4.16/0.6-kV Unit/Station Services Transformer	6		
		4.16 kV MV switchgear	Lot		
		600 V switchgear	Lot		
		600 V MCC's	Lot		
64	Auxiliary AC Power Distribution (Common)	Emergency Diesel Generator	0		
65	UPS Supply and Distribution (per Unit)	110-V, 1 ph, 50 Hz Power Distribution	Lot		
	DC Supply (Common)	125 VDC Supply and Distribution System	2		
66	Cabling Systems	Power, Control and Instrumentation	Lot		
67	Building and Outdoor Electrical Services		Lot		
	Grounding grid	Will be tied into existing plant grid.	Lot		
70	**Instrumentation and Control**				
71	Central Control System, incl. DCS		Lot		
72	Power generation & Auxiliaries I&C		Lot		
73	Common Sevices and equipment I&C		Lot		

Appendix F3:
4 Unit Combustion Turbine – Brownfield

HATCH

Equipment List

Originator:	**Date Submitted:**	**Project No.:**	**Revision:**
Hatch	10/26/2022	H-369039	C
Client:	**Project Name:**		**Discipline:**
Newfoundland and Labrador Hydro	Combustion Turbine Screening	Brown Field 4 units	Thermal Power
Document Number:	**Hatch Responsible Project Manager:**		Karim Meghari
H-369039-00000-200-216-005			
	Client Representative:		Ryan Cooper

WBS #	Description	Description of sub-components	Quantity	Duty % /Volume	Notes
Equipment List:					
10	**Gas Turbine Generator**	Gas Turbine Generator with Exhaust Door	4		
		Gas Turbine Fuel Module	4		
		Generator Breaker Enclosure			
		GT Electrical and Control Compartment	4		
		Exhaust Frame Blower	8		
		GT Coolling Water Module	4		
		Lube Oil Demister	4		
	Gas Turbine Firefighting Skid	Gas Turbine Firefighting Skid	2		Vortex / FM200
	Gas Turbine Wash Pakage	Gas Turbine Water Was Skid	2		
20	**Common Services Equipment and Systems**				
21	**Plant Water Systems (Common)**				
	Service Water System	Service Water Storage Tank	0		2 days water storage for 4 GTs
		Service Water Pumps	0	100	
		Strainers	0	100	
		Piping/Hoses	Lot		
	2-Stage Reverse Osmosis(RO)	2 parallel trains		100	
		First Stage RO pumps	4	100	
		First Stage Membrane Units	4	100	
		Break Tank	2	100	
		Energy recovery devices	4	100	
		Caustic Soda Tote and Pump	2	100	
		Second Stage RO Pumps	4	100	
		Second Stage Membrane Units	4	100	
		RO Product Water Tank	2		
		RO Reject to CW Weir	Lot		
		Piping Valves, etc.	Lot		
		Clean-in-Place Skid (for membrane cleaning)	Lot		
	DI Water	RO Product Water Pumps	4	100	
		Electrodeionization (EDI) Units	4	100	
		DI Water Tank	1	1000 m3	2 days Demin water storage for 4 GTs at 100% capacity
	Waste Water System	Wastewater Collection Sumps			
		Wastewater Collection Sump Pumps			
		Fuel Storage Sump			
		Fuel Storage Sump Pump			
		Dirty Water Sump			
		Dirty Water Sump Pump			
		Piping Systems			
		Oily Water Seperator			
		Waste Water Catch Basin			
		Sanitary Sewage System			
23	Compressed Air, Gas & Vacuum Systems				
	Plant Air & Instrument Air System	Air Compressors	0	100	Screw type Compressor. Two per GT
		Instrument Air Dryers	0	100	One per Unit. Regenerative or Desicant
		Service Air Receiver (per Unit)	0	100	Vertical
		Instrument Air Receiver (per Unit)	0	50	Vertical
		Piping & Valves	Lot		
24	Lubricating Oil Storage/treatment	Oil Cleaning Unit (per Unit)	2		
25	Emergency Diesel Generators	Emergency Diesel Generators	2		
26	Fire Protection Systems	Water Storage (Fire Water Tank)	1	2000 m3	2 hours Fire water storage
		Main Pump - electric	2	100	
		Emergency/backup Pump -diesel	2	100	
		Jockey Pump - electric	2	Maintain pressure	
		Water Ring Main System	Lot		
		Dry Deluge Spray System	Lot		
		Valved Fire Water Connections	Lot		
		Yard Hydrant & Hose Station	Lot		
		Wet System Sprinklers	Lot		
		Portable Dry Chemical Extinguishers	Lot		
		CO2 systams	Lot		
30	**Fuel Supply and Storage**				
31	Diesel Handling & Storage (Common)	Diesel Storage Tanks	2	5600 m3 each	7 days storage for 4 GTs operating at baseload (100% GT capacity)
		Fuel Metering	2		
		Fuel heaters	2	100	Electric heaters
		Interconnecting piping and piping to gas turbine	Lot		
		Fuel Supply to Diesel Generator		100	
		Fuel Forwarding Pumps	4	100	
		Oil separator	4		
		Fuel Offloading Pumps	2	100	
32	Biofuel	Biofuel Storage Tank	2	5600 m3 each	7 days storage for 4 GT.
		Fuel Metering	2		
		Interconnecting piping and piping to gas turbine	Lot		
		Fuel Pumps	4	100	
		Fuel offloading Pumps	2	100	
40	**Miscellaneous Equipment & Systems**				
41	Workshop Equipment and Tools		Lot		
	Laboratory and Test Equipment		Lot		
50	**Environmental (Emissions) Control Systems (per Unit)**				
	Continuous Emission Monitoring (Unit)	One system for each flue	2		
60	**Electrical Power Systems**				
61	240-kV Main Power Output System (per Unit)	Main 11/240-kV Power Transformer (TP at HV	4		
		Generator Isolated-phase Bus System	Lot		
		Generator Circuit Breakers	4		
		Metering and Protection	Lot		
		Grounding System	Lot		
62	Auxiliary Power Supply system	11/4.16 kV Unit Auxiliary Transformer	4		
63	Unit/Station Power Supply system	4.16/0.6-kV Unit/Station Services Transformer	12		
		4.16 kV MV switchgear	Lot		
		600 V switchgear	Lot		
		600 V MCC's	Lot		
64	Auxiliary AC Power Distribution (Common)	Emergency Diesel Generator	2		
65	UPS Supply and Distribution (per Unit)	110-V, 1 ph, 50 Hz Power Distribution	Lot		
	DC Supply (Common)	125 VDC Supply and Distribution System	4		
66	Cabling Systems	Power, Control and Instrumentation	Lot		
67	Building and Outdoor Electrical Services		Lot		
	Grounding grid	Will be tied into existing plant grid.	Lot		
70	**Instrumentation and Control**				
71	Central Control System, incl. DCS		Lot		
72	Power generation & Auxiliaries I&C		Lot		
73	Common Sevices and equipment I&C		Lot		

Appendix F4:
4 Unit Combustion Turbine – Greenfield

HATCH

Equipment List

Originator:	**Date Submitted:**	**Project No.:**	**Revision:**
Hatch	10/26/2022	H-369039	C
Client:	**Project Name:**		**Discipline:**
Newfoundland and Labrador Hydro	Combustion Turbine Screening	Green Field 4 units	Thermal Power
Document Number:	**Hatch Responsible Project Manager:**		Karim Meghari
H-369039-00000-200-216-003			
	Client Representative:		Ryan Cooper

WBS #	Description	Description of sub-components	Quantity	Duty % /Volume	Notes
Equipment List:					
10	**Gas Turbine Generator**	Gas Turbine Generator with Exhaust Door	4		
		Gas Turbine Fuel Module	4		
		Generator Breaker Enclosure			
		GT Electrical and Control Compartment	4		
		Exhaust Frame Blower	8		
		GT Coolling Water Module	4		
		Lube Oil Demister	4		
	Gas Turbine Firefighting Skid	Gas Turbine Firefighting Skid	2		Vortex / FM200
	Gas Turbine Wash Pakage	Gas Turbine Water Was Skid	2		
20	**Common Services Equipment and Systems**				
21	**Plant Water Systems (Common)**				
	Service Water System	Service Water Storage Tank	1	2000 m3	2 days water storage for 4 GTs at 100% capacity
		Service Water Pumps	4	100	
		Strainers	4	100	
		Piping/Hoses	Lot		
	2-Stage Reverse Osmosis(RO)	2 parallel trains		100	
		First Stage RO pumps	4	100	
		First Stage Membrane Units	4	100	
		Break Tank	2	100	
		Energy recovery devices	4	100	
		Caustic Soda Tote and Pump	2	100	
		Second Stage RO Pumps	4	100	
		Second Stage Membrane Units	4	100	
		RO Product Water Tank	2		
		RO Reject to CW Weir	Lot		
		Piping Valves, etc.	Lot		
		Clean-in-Place Skid (for membrane cleaning)	Lot		
	DI Water	RO Product Water Pumps	4	100	
		Electrodeionization (EDI) Units	4	100	
		DI Water Tank	1	1000 m3	2 days Demin water storage for 4 GTs at 100% capacity
	Waste Water System	Wastewater Collection Sumps			
		Wastewater Collection Sump Pumps			
		Fuel Storage Sump			
		Fuel Storage Sump Pump			
		Dirty Water Sump			
		Dirty Water Sump Pump			
		Piping Systems			
		Oily Water Seperator			
		Waste Water Catch Basin			
		Sanitary Sewage System			
23	Compressed Air, Gas & Vacuum Systems				
	Plant Air & Instrument Air System	Air Compressors	8	100	Screw type Compressor. Two per GT
		Instrument Air Dryers	4	100	One per Unit. Regenerative or Desicant
		Service Air Receiver (per Unit)	4	100	Vertical
		Instrument Air Receiver (per Unit)	4	50	Vertical
		Piping & Valves	Lot		
24	Lubricating Oil Storage/treatment	Oil Cleaning Unit (per Unit)	2		
25	Emergency Diesel Generators	Emergency Diesel Generators	2		
26	Fire Protection Systems	Water Storage (Fire Water Tank)	1	2000 m3	2 hours Fire water storage
		Main Pump - electric	2	100	
		Emergency/backup Pump -diesel	2	100	
		Jockey Pump - electric	2	100	
		Water Ring Main System	Lot		
		Dry Deluge Spray System	Lot		
		Valved Fire Water Connections	Lot		
		Yard Hydrant & Hose Station	Lot		
		Wet System Sprinklers	Lot		
		Portable Dry Chemical Extinguishers	Lot		
		CO2 systems	Lot		
30	**Fuel Supply and Storage**				
31	Diesel Handling & Storage (Common)	Diesel Storage Tanks	2	5600 m3 each	7 days storage for 4 GTs operating at baseload (100% GT capacity)
		Fuel Metering	2		
		Fuel heaters	2	100	Electric heaters
		Interconnecting piping and piping to gas turbine	Lot		
		Fuel Supply to Diesel Generator		100	
		Fuel Forwarding Pumps	4	100	
		Oil separator	4		
		Fuel Offloading Pumps	2	100	
32	Biofuel	Biofuel Storage Tank	2	5600 m3 each	7 days storage for 4 GT.
		Fuel Metering	2		
		Interconnecting piping and piping to gas turbine	Lot		
		Fuel Pumps	4	100	
		Fuel offloading Pumps	2	100	
40	**Miscellaneous Equipment & Systems**				
41	Workshop Equipment and Tools		Lot		
	Laboratory and Test Equipment		Lot		
50	**Environmental (Emissions) Control Systems (per Unit)**				
	Continuous Emission Monitoring (Unit)	One system for each flue	2		
60	**Electrical Power Systems**				
61	240-kV Main Power Output System (per Unit)	Main 11/240-kV Power Transformer (TP at HV	4		
		Generator Isolated-phase Bus System	Lot		
		Generator Circuit Breakers	4		
		Metering and Protection	Lot		
		Grounding System	Lot		
62	Auxiliary Power Supply system	11/4.16 kV Unit Auxiliary Transformer	4		
63	Unit/Station Power Supply system	4.16/0.6-kV Unit/Station Services Transformer	12		
		4.16 kV MV switchgear	Lot		
		600 V switchgear	Lot		
		600 V MCC's	Lot		
64	Auxiliary AC Power Distribution (Common)	Emergency Diesel Generator	2		
65	UPS Supply and Distribution (per Unit)	110-V, 1 ph, 50 Hz Power Distribution	Lot		
	DC Supply (Common)	125 VDC Supply and Distribution System	4		
66	Cabling Systems	Power, Control and Instrumentation	Lot		
67	Building and Outdoor Electrical Services		Lot		
	Grounding grid	Will be tied into existing plant grid.	Lot		
70	**Instrumentation and Control**				
71	Central Control System, incl. DCS		Lot		
72	Power generation & Auxiliaries I&C		Lot		
73	Common Sevices and equipment I&C		Lot		

Appendix G:
Cost Estimate

Appendix G1:
2 Unit Combustion Turbine – Brownfield

Simple Cycle Power Plant Project

Capital Cost Estimate for Screening Study (FEL-1)

HATCH

Order of Magnitude Cost Estimate Summary - Canada

Project:	Simple Cycle Power Plant
Location:	**Newfoundland and Labrador - Brown Field Site**
Description:	Simple Cycle Power Plant
Study Option:	**Two (2) Gas Turbines**
Project Number:	H369039
Originated By:	Tia Ghantous
Checked by:	Karim Meghari
Currency:	CAD

WBS	Description	Material	Labour	Constr. Equip.	Sub-Contractor	Total Cost
100	*Site and Improvements Total*	1,970,504			150,000	2,121,000
200	*Building's, Structures and Foundations Total*	7,184,000	3,296,000	82,000	5,764,000	16,326,000
300	*Not Used*					
400	*Power Generation and Auxiliaries Total*	66,504,109	4,491,270	927,360	314,116	72,237,000
500	*Electrical Power Systems Total*	14,108,920	3,802,133	0	102,525	18,014,000
600	*Instrumentation and Control Total*	4,197,504	1,976,101			6,174,000
700	*Common Services Equipment and Systems Total*	3,684,530	5,618,340		331,008	9,634,000
750	*Diesel oil, Biofuel, Rawa Water, Fire Water and Demin water tanks*	13,031,628	1,932,200			14,964,000
800	*Construction Management Total Inculding Indirects*	987,058	9,240,537	561,753	264,000	11,053,000
					Total Direct Cost	150,523,000
900	*Engineering and Project Managemnet Total*					20,952,000
1000	*Misc. Freigtht, Spares, Commisioning etc. (5%)*					7,526,000
1100	*Owner's Costs*					
1200	*Bonds and Insurance (1.4%)*					2,401,000
1300	*Contingencies 20%*					34,775,000
					Total Project Cost	216,177,000
					Cost /kW	2,162

Appendix G2:
2 Unit Combustion Turbine – Greenfield

Simple Cycle Power Plant Project

Capital Cost Estimate for Screening Study (FEL-1)

HATCH

Order of Magnitude Cost Estimate Summary - Canada

Project:	Simple Cycle Power Plant
Location:	**Newfoundland and Labrador Green Field Site**
Description:	Simple Cycle Power Plant
Study Option:	**Two (2) Gas Turbines**
Project Number:	H369039
Originated By:	Tia Ghantous
Checked by:	Karim Meghari
Currency:	CAD

WBS	***Description***	***Material***	***Labour***	***Constr. Equip.***	***Sub-Contractor***	***Total Cost***
100	*Site and Improvements Total*	2,364,605			150,000	2,515,000
200	*Building's, Structures and Foundations Total*	8,060,000	3,645,000	82,000	7,090,000	18,877,000
300	*Not Used*					
400	*Power Generation and Auxiliaries Total*	66,504,109	4,491,270	927,360	314,116	72,237,000
500	*Electrical Power Systems Total*	14,868,553	4,152,622	0	102,525	19,124,000
600	*Instrumentation and Control Total*	4,197,504	1,976,101			6,174,000
700	*Common Services Equipment and Systems Total*	4,345,870	5,963,790		348,458	10,658,000
750	*Diesel oil, Biofuel, Rawa Water, Fire Water and Demin water tanks*	16,298,783	2,422,274			18,721,000
800	*Construction Management Total Inculding Indirects*	976,983	9,137,957	532,445	264,000	10,911,000
					Total Direct Cost	159,217,000
900	*Engineering and Project Managemnet Total*					20,778,000
1000	*Misc. Freigtht, Spares, Commisioning etc. (5%)*					7,961,000
1100	*Owner's Costs*					
1200	*Bonds and Insurance (1.4%)*					2,520,000
1300	*Contingencies 20%*					36,503,000
					Total Project Cost	226,979,000
					Cost /kW	2,270

Appendix G3:
4 Unit Combustion Turbine – Brownfield

Simple Cycle Power Plant Project

Capital Cost Estimate for Screening Study (FEL-1)

HATCH™

Order of Magnitude Cost Estimate Summary - Canada

Project:	Simple Cycle Power Plant
Location:	**Newfoundland and Labrador - Brown Field Site**
Description:	Simple Cycle Power Plant
Study Option:	**Four (4) Gas Turbines**
Project Number:	H369039
Originated By:	Tia Ghantous
Checked by:	Karim Meghari
Currency:	CAD

WBS	Description	Material	Labour	Constr. Equip.	Sub-Contractor	Total Cost
100	*Site and Improvements Total*	3,152,806			150,000	3,303,000
200	*Building's, Structures and Foundations Total*	12,519,000	5,824,000	159,000	11,277,000	29,779,000
300	*Not Used*					
400	*Power Generation and Auxiliaries Total*	131,239,032	8,350,858	3,709,440	675,186	143,975,000
500	*Electrical Power Systems Total*	19,492,861	5,060,063	0	185,525	24,738,000
600	*Instrumentation and Control Total*	8,370,004	2,984,101			11,354,000
700	*Common Services Equipment and Systems Total*	4,934,073	6,110,790		365,908	11,411,000
750	*Diesel oil, Biofuel, Rawa Water, Fire Water and Demin water tanks*	24,930,071	3,696,383			28,626,000
800	*Construction Management Total Inculding Indirects*	1,192,026	11,716,101	749,457	330,000	13,988,000
					Total Direct Cost	267,174,000
	,					
900	*Engineering and Project Managemnet Total*					30,013,000
1000	*Misc. Freigtht, Spares, Commisioning etc. (5%)*					13,359,000
1100	*Owner's Costs*					
1200	*Bonds and Insurance (1.4%)*					4,161,000
1300	*Contingencies 20%*					60,270,000
					Total Project Cost	374,977,000
					Cost /kW	1,875

Appendix G4:
4 Unit Combustion Turbine – Greenfield

Simple Cycle Power Plant Project

Capital Cost Estimate for Screening Study (FEL-1)

HATCH

Order of Magnitude Cost Estimate Summary - Canada

Project:	Simple Cycle Power Plant
Location:	**Newfoundland and Labrador - Green Field Site**
Description:	Simple Cycle Power Plant
Study Option:	**Four (4) Gas Turbines**
Project Number:	H369039
Originated By:	Tia Ghantous
Checked by:	Karim Meghari
Currency:	CAD

WBS	Description	Material	Labour	Constr. Equip.	Sub-Contractor	Total Cost
100	*Site and Improvements Total*	3,546,907			150,000	3,697,000
200	*Building's, Structures and Foundations Total*	13,395,000	6,173,000	159,000	12,602,000	32,329,000
300	*Not Used*					
400	*Power Generation and Auxiliaries Total*	131,239,032	8,350,858	3,709,440	675,186	143,975,000
500	*Electrical Power Systems Total*	20,699,355	5,653,023	0	185,525	26,538,000
600	*Instrumentation and Control Total*	8,370,004	2,984,101			11,354,000
700	*Common Services Equipment and Systems Total*	5,261,573	6,467,790		365,908	12,095,000
750	*Diesel oil, Biofuel, Rawa Water, Fire Water and Demin water tanks*	28,055,364	4,165,039			32,220,000
800	*Construction Management Total Inculding Indirects*	1,203,399	11,831,898	782,542	330,000	14,148,000
					Total Direct Cost	276,356,000
	,					
900	*Engineering and Project Managemnet Total*					30,737,000
1000	*Misc. Freigtht, Spares, Commisioning etc. (5%)*					13,818,000
1100	*Owner's Costs*					
1200	*Bonds and Insurance (1.4%)*					4,299,000
1300	*Contingencies 20%*					62,278,000
					Total Project Cost	387,488,000
					Cost /kW	1,937

Appendix H: Specification Sheet

Gas Turbine Generator – Specification Sheet

Introduction

This scope of work describes the minimum requirements for the design, fabrication, assembly and testing of two aeroderivative gas turbine generators with a nominal output of 130MW, with less than 10 min start up time.

The turbines shall be able to run on liquid biofuel, demonstrated experience and reference(s) is a must.

Winterization and power augmentation packages should be included in proposal.

The turbines will be operating as a peaking plant with estimated 500 hours of operation a year with a capability to operate as a synchronous condenser.

Scope of supply is as follows:

Multistage axial flow compressor
Specify unit start up time
Fuel System
Inlet and exhaust plenum
Gearbox (if required)
Coupling(s) and coupling guards.
Vibration sensors
Thermocouples for measuring critical turbine temperatures
Turbine inlet air system with self-cleaning filter, silencers, expansion joints, ducts, structural support, and instrumentation
Turbine exhaust system with exhaust silencers, expansion joints, ducts, and instrumentation
Structural steel assembly
Fire Protection system
Air cooled generator, open ventilated complete with generator enclosure
Stator winding with class F insulation
Cylindrical forged steel rotor with class F insulation
Class B temperature rises rotor/stator
Generator cooling system
Lubrication system integral with the gas turbine lubrication system
Stainless steel gauges and switches
Bearing lube oil vapor extraction
Generator stator heater
Generator grounding system
Turbine generator supervisory system
Turbine control panels
Generator protective relays
Automatic voltage regulator

General Design Data for estimated performance

Site:	Newfoundland and Labrador
Location:	Indoors
Air Quality:	Good (no particulate)
Elevation:	152m
Ambient Temperature:	15ºC min/20ºC max
Relative humidity:	60%

Fuel: Diesel no 2

NOx Emissions Requirements:

Fuel Type	Compliance Limit (ppm)	Performance Target (ppm)
Diesel	Canadian Environmental Protection Act: guidelines, objectives and codes of practice	38

Information Required with Quotation

The following information shall be supplied with the Quotation:

- Equipment Scope Description
- Vendor standard data sheet with performance and design data, material selections, etc.
- Preliminary Equipment arrangement drawings, including dimensions
- Emission guarantees
- Weight of equipment
- Manufacturing and delivery schedule
- Vendor shall include a priced list of recommended spare parts for start-up and initial operation of the equipment and a priced list of spare parts for two-years of normal operation in the proposal.

Appendix I:
GTG Comparison Sheet

GTG Evaluation Sheet- Vendor feedback

	Company Name		
	GE- LM6000 PC	Siemens – SGT800	MHI – FT4000
Equipment Cost (1 unit) (CAD)	$34,078,995	$24,903,100	$34,738,580
Unit Delivery	14 months for 1 unit	17 months from Sweden	Q4 2022
Synchronous Condenser	yes	yes	yes
NOx Emission	42 ppm	<74 ppmvd	42 ppm
Fuel Capability	Diesel, Biodiesel, Ethanol, Hydrogen (35%)	Hydrogen (75%), Biodiesel, Diesel	Diesel
Water Injection	Yes	No	No
Power Augmentation	Sprint	No	Wet compression
Cost of Delivery	Included	Not Provided	Not Provided
10 min fast start capability	Yes	No	Yes
Technology	Aeroderivative Turbine	Industrial Turbine	Aeroderivative Turbine

Appendix J:
Experience List

Appendix J1:
GE – LM6000

Only units operating on alternate fuels have been included

Award Year	COUNTRY	CUSTOMER TYPE	MODEL (DETAIL)	PRIMARY FUEL	SECONDARY FUEL	NUMBER OF UNITS
1995	INDIA	INDUSTRIAL	LM6000	NAPHTHA	OIL/DIESEL	1
1996	INDIA	INDUSTRIAL	LM6000	NAPHTHA	OIL/DIESEL	1
1997	INDIA	UTILITY	LM6000PC	NAPHTHA	OIL/DIESEL	3
1997	TURKEY	INDUSTRIAL	LM6000PC	NAPHTHA	GAS/NATURAL	1
1998	INDIA	INDUSTRIAL	LM6000	NAPHTHA	OIL/DIESEL	2
1998	TURKEY	INDUSTRIAL	LM6000	GAS/NATURAL	NAPHTHA	1
1998	TURKEY	IPP	LM6000	GAS/NATURAL	NAPHTHA	2
1998	TURKEY	INDUSTRIAL	LM6000	GAS/NATURAL	NAPHTHA	1
1999	INDIA	IPP	LM6000PC	NAPHTHA	OIL/DISTILLATE	4
2000	INDIA	IPP	LM6000PC	NAPHTHA	OIL/DISTILLATE	1
2000	BRAZIL	IPP	LM6000PC	GAS/NATURAL	BIOMASS	1
2004	USA	UTILITY	LM6000PC	NAPHTHA		1
2015	REUNION	IPP	LM6000PC	ETHANOL	OIL/DIESEL	1
				TOTAL		**20**

Appendix J2:
Siemens – SGT-800

Green back up power plant

Customer: Stockholm Exergi AB

Country: Sweden

Commercial operation: 2023

March 2022

Reference
Stockholm Exergi, Sweden

Challenge

- Security of supply is increasingly important with fluctuating renewables and insufficient transmission capability
- Need of fast starting dispatchable power with black start capability securing electricity to the city of Stockholm at all times
- Stockholm Exergi is targeting to become climate positive in their operations latest by 2025

Technology

- 1 x SGT-800 gas turbine
- Black start diesel generator
- PCS 7 control system
- Installation and commissioning

Solution

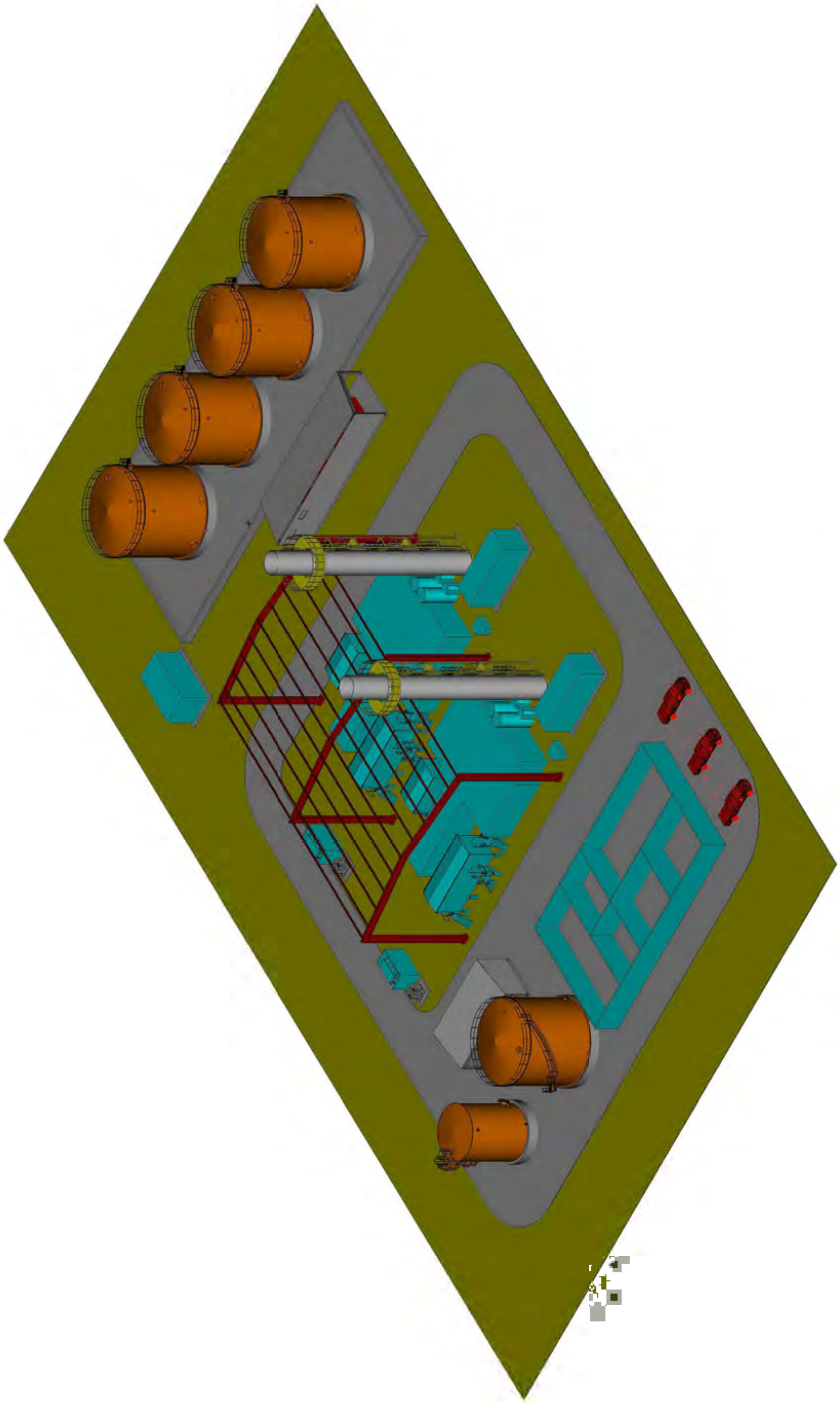
- The new simple cycle back-up gas turbine power plant will provide emergency power to the city of Stockholm
- The plant will be operated on liquid green bio-diesel, enabling Stockholm Exergi to reach their target of becoming climate positive by 2025

Benefits

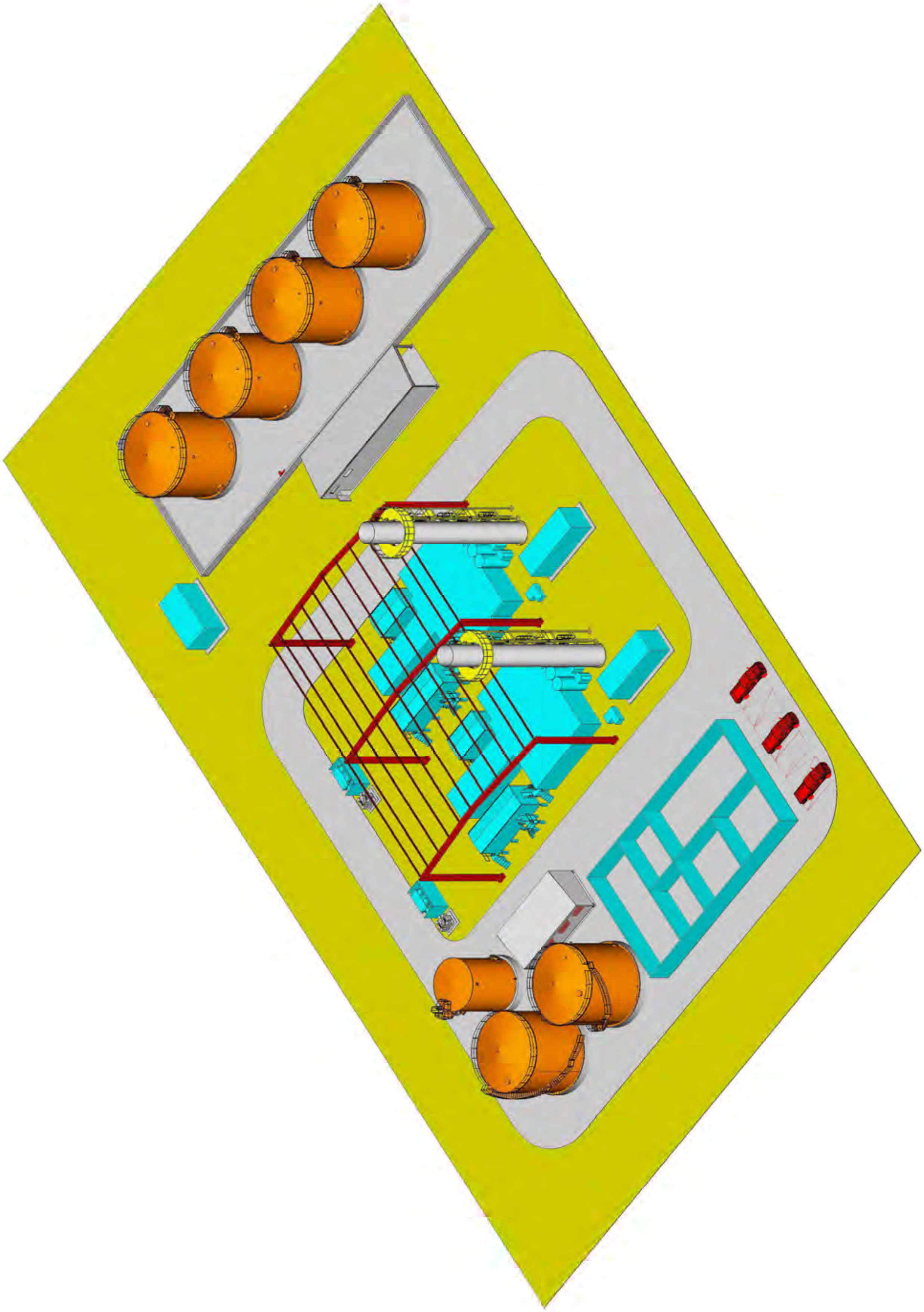
- Capability to operate on liquid green fuel enabling fossil free power generation
- Reliable and secure solution with fast start capability
- High electrical efficiency
- The project is contributing to the city of Stockholm's goal to become a fossil free city

Appendix K:
3D Model

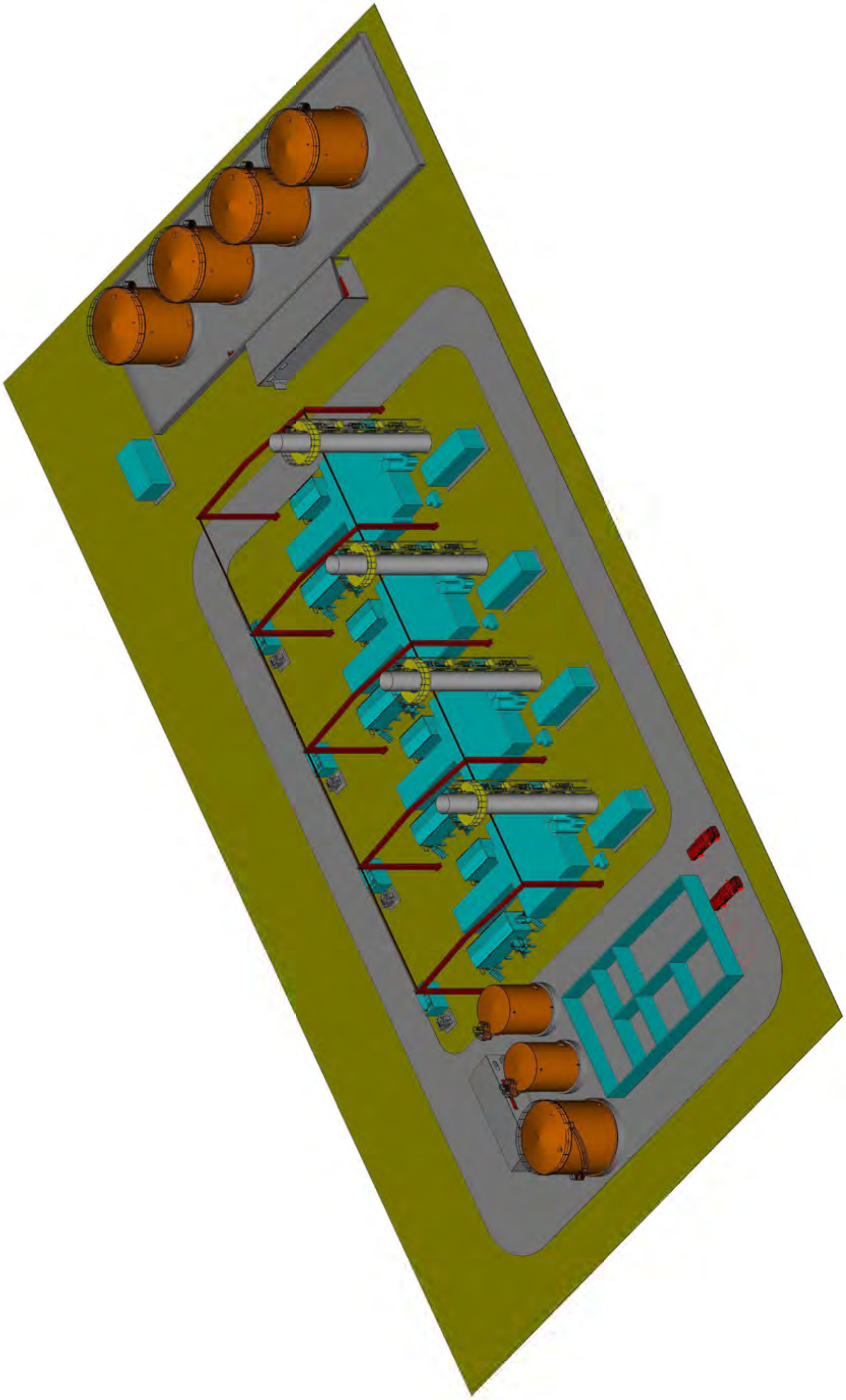
Appendix K1:
2 Unit Combustion Turbine – Brownfield



Appendix K2:
2 Unit Combustion Turbine – Greenfield



Appendix K3:
4 Unit Combustion Turbine – Brownfield



Appendix K4:
4 Unit Combustion Turbine – Greenfield