Newfoundland and Labrador Hydro
Hydro Place. 500 Columbus Drive
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 | f. 709.737.1800
nlhydro.com

June 15, 2026

Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Mike McNiven
Board Secretary

Re: ***Reliability and Resource Adequacy Study Review* – Condition Assessment and Retirement Optimization Study**

Please find enclosed Newfoundland and Labrador Hydro's Condition Assessment and Retirement Optimization Study for the Hardwoods and Stephenville Gas Turbines, as committed in the *Reliability and Resource Adequacy Study Review* semi-annual update.[1]

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Shirley A. Walsh
Senior Legal Counsel, Regulatory
SAW/kd

Encl.

ecc:

Board of Commissioners of Public Utilities
Jacqui H. Glynn
Ryan Oake
Board General

Island Industrial Customer Group
Paul L. Coxworthy, Stewart McKelvey
Denis J. Fleming, Cox & Palmer
Glen G. Seaborn, Poole Althouse

Labrador Interconnected Group
Senwung F. Luk, Olthuis Kleer Townshend LLP
Nicholas E. Kennedy, Olthuis Kleer Townshend LLP

Consumer Advocate
Adrienne H.Y. Ding, O'Dea Earle
Justin W. King, O'Dea Earle
Consumer Advocate General

Newfoundland Power Inc.
Dominic J. Foley
Douglas W. Wright
Regulatory Email

[1] "*Reliability and Resource Adequacy Study Review* – Semi-Annual Update for the Fourth Quarter of 2025," Newfoundland and Labrador Hydro, December 16, 2025.

Hardwoods and Stephenville Life Extension Condition Assessment

Overview

June 15, 2026

A report to the Board of Commissioners of Public Utilities

Contents

1.0 Context within the RRA Study Review 1
2.0 Background 3
3.0 Condition Assessment and Retirement Optimization Study 3
3.1 Scope and Methodology 3
3.2 Hardwoods Gas Turbine 4
3.2.1 Condition Assessment and Findings 4
3.2.2 Sustaining Capital and Operating Plan 5
3.3 Stephenville Gas Turbine 6
3.3.1 Condition Assessment and Findings 6
3.3.2 Sustaining Capital and Operating Plan 7
3.4 Retirement Recommendations 8
3.5 Considerations for Resource Planning 9
4.0 Combustion Turbine Replacement Study 9
4.1 Replacement Technology Review 9
4.2 Synchronous Condensing Considerations 10
4.3 Conceptual Replacement Configurations 11
4.4 Class 5 Cost Estimates 11
5.0 Conclusion and Next Steps 12

List of Attachments

Attachment 1: Condition Assessment and Retirement Optimization Study

Attachment 2: CT Replacement Study Cost Estimate Report

1.0 Context within the RRA Study Review

Newfoundland and Labrador Hydro ("Hydro") filed the initial Reliability and Resource Adequacy Study ("RRA Study") with the Board of Commissioners of Public Utilities ("Board") in November 2018 ("2018 Filing").[1] Since the 2018 Filing, throughout the continued *Reliability and Resource Adequacy Study Review* proceeding ("*RRA Study Review*"), Hydro has filed regular updates to the RRA Study, including numerous technical notes, additional studies, and third-party reports. The regulatory record is appropriately robust given the rapid transformation of the provincial electricity system, including interconnection, asset retirement, new resources, and increasing demand.

Hydro's 2024 Resource Adequacy Plan,[2] submitted to the Board on July 9, 2024, provided Hydro's recommended Minimum Investment Required Expansion Plan. After completing a series of technical conferences with Board staff and intervening parties, Hydro and the intervenors gained consensus on a number of issues ("Settled Issues") which were enumerated in a Settlement Agreement.[3] The Settled Issues include agreement that the recommendation to build a new 150 MW unit at Bay d'Espoir (Unit 8) and a 150 MW Combustion Turbine ("CT") on the Avalon Peninsula ("Avalon CT") is appropriate as part of the first step in addressing the requirements for additional capacity for the Island Interconnected System, and applications for these projects should be filed for evaluation. In line with the Settled Issues, Hydro filed its 2025 Build Application for both of these assets in March 2025; the regulatory proceeding is ongoing.

Hydro will have to make significant investments in the coming years and decades to maintain its legislative obligation of the provision of safe, least-cost, reliable electrical service in an environmentally responsible manner to the province.[4] The recommended assets within Hydro's Minimum Investment Required portfolio are just that, the Minimum Investment Required to meet Hydro's obligations, with additional investment necessary to meet Hydro's most likely to occur Reference Case. As such, through the *RRA Study Review*, Hydro models its system expansion in consideration of various forecast scenarios and within the context of continuously evolving energy policy. The numerous studies that Hydro has

[1] "Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. September 6, 2019 (originally filed November 16, 2018).
[2] "2024 Resource Adequacy Plan – An Update to the Reliability and Resource Adequacy Study," Newfoundland and Labrador Hydro, rev. August 26, 2024 (originally filed July 9, 2024).
[3] "2025 Build Application – Bay d'Espoir Unit 8 and Avalon Combustion Turbine ("2025 Build Application")," Newfoundland and Labrador Hydro, March 21, 2025, sch. 2.
[4] *Electrical Power Control Act*, 1994, SNL 1994, c E-5.1, s 3(b)(iii).

completed and planned are all necessary to validate and justify the information that Hydro inputs into its models, which produce critical information on which timely, prudent decisions are to be made.

Due to the historical reliability issues and age of the gas turbines ("GT"), Hydro has assumed retirement of the Hardwoods and Stephenville GTs in 2030, or once adequate alternative generation is brought online and proven reliable. To ensure its retirement assumptions are prudent and fully informed, Hydro commissioned Hatch Ltd. ("Hatch") to complete a condition assessment and retirement optimization study ("Hatch Condition Assessment") for the Hardwoods and Stephenville generating stations; Hydro also commissioned a Class 5 cost estimate for asset replacement (collectively, the "Studies"). The intention of these Studies is to provide planning inputs for the potential continued operation or retirement of these assets and to inform Hydro's RRA Study, specifically the Reference Case requirements.

The enclosed reports were prepared by Hatch to support Hydro's understanding of:

- The current condition and remaining useful life of the Hardwoods and Stephenville generating stations;
- The sustaining capital and operating expenditures required to maintain continued operation;
- The operational and reliability risks associated with continued operation of the existing assets; and
- Conceptual replacement options and associated Class 5 capital cost estimates for future replacement GT generating units.

The Studies form part of Hydro's broader long-term planning activities and are intended to support future decision-making regarding the retirement, replacement, and continued operational role of the Hardwoods and Stephenville GTs within the Island Interconnected System. Hatch's findings will be utilized as inputs into Hydro's next RRA Study update to meet the Reference Case requirements and future transmission planning assessments.

While the enclosed Studies provide valuable, necessary information, they cannot and should not be considered independent of the rest of the studies and analyses ongoing through the *RRA Study Review*. Rather, the Studies are inputs that will—along with other studies completed and ongoing—inform Hydro's broader system resource planning process now and into the future.

2.0 Background

The Hardwoods and Stephenville GTs entered service in 1976 and 1975, respectively. Each unit consists of two 25 MW Rolls-Royce Olympus C-type 2022 GTs, coupled via clutches to a power turbine and a shared 63.5 MVA generator. These units provide standby generation and operate as synchronous condensers to support grid stability.

Both facilities were originally designed for a service life of approximately 20 to 25 years and have now exceeded 50 years in operation. Although the facilities have been reasonably maintained, Hatch identified increasing operational and reliability risks associated with aging infrastructure, and equipment degradation and obsolescence.

A key concern identified through the Hatch Condition Assessment is the obsolescence of the Rolls-Royce Olympus GT fleet. Production of these GTs ceased in the early 2000s and original equipment manufacturer support is no longer available. Hydro now relies on Sulzer, following its acquisition of Alba Power, as the primary service provider available to support the Olympus fleet. In circumstances where replacement parts are unavailable, manufacturing lead times may extend up to nine months creating risk to operational readiness.

The Studies also recognize that the operational role of the Hardwoods and Stephenville facilities extends beyond conventional backup generation. Both units provide synchronous condensing capability, which has implications to system voltage support and stability. In addition, the assets support regional reliability.[5] Accordingly, the Studies evaluate not only the condition and remaining useful life of the existing assets, but also conceptual replacement options capable of providing both standby generation and synchronous condensing capability in the future.

3.0 Condition Assessment and Retirement Optimization Study

3.1 Scope and Methodology

The Hatch Condition Assessment, provided as Attachment 1, was completed to determine the remaining useful life and optimal retirement timing for the Hardwoods and Stephenville GTs and to estimate the

[5] Upon decision to retire either asset, Hydro will need to evaluate any potential required upgrades due to aspects such as increases to the loading of 230/66 kV power transformers when these generators are no longer available for backup supply.

capital and operating costs required to reliably operate the plants until retirement. While this study identifies the *optimal* retirement timing for these units, Hatch states that its recommendations are based solely on the assessed condition of the individual assets and do not consider the wider Hydro system needs and cost impacts. As such, the context of the needs of the Island Interconnected System could have implications for the recommended timeframe. Retirement decisions for Hardwoods and Stephenville would be made in consideration of the entire Island Interconnected System, and that may differ from the recommendations made by Hatch. For example, Hatch recommends retiring Hardwoods first based strictly on run time and component condition; however, Hydro may choose to retire Stephenville first due to operational and system requirements, such as proximity to load centres.

In preparation of the condition assessment, Hatch completed a document review of design information and historical records, including plant design documents, operating history, plant performance and availability information, major maintenance history, major overhauls, and preventative maintenance documentation.

Hatch also completed site visits at Hardwoods and Stephenville in April and May 2025. Mechanical, electrical, instrumentation and controls, and structural engineering personnel visually assessed major plant systems and discussed operating and maintenance status with Hydro personnel. The assessment included review of the GT engines, generators, fuel systems, lube oil systems, compressed air systems, switchgear, control systems, black-start diesel generator systems, fire suppression systems, and buildings and facilities.

The site assessment was visual and non-intrusive. It provided a condition overview of the facilities and did not include detailed internal inspection of components. Sustaining capital forecasts were developed based on assessed condition, recent inspection and repair history, operating hours and starts, repairs identified through the review, typical asset life, and historical cost information escalated for planning purposes.

3.2 Hardwoods Gas Turbine

3.2.1 Condition Assessment and Findings

The Hardwoods GT provides standby generation and reactive power support as a synchronous condenser.

Hatch identified that the Hardwoods GTs are operating well beyond their original design life. While the facility appears to remain in reasonable condition, the advanced age of the GT units introduces increased risk of failure due to degradation mechanisms such as fatigue and material embrittlement.

The broader Olympus fleet operating experience is also a concern. Between Hardwoods and Stephenville, the GT engines have required 11 overhauls, with an average overhaul interval of approximately 330 starts and 500 operating hours. Hatch notes that certain failures have occurred after very limited operation following overhaul, including one instance after approximately 30 hours of operation.

Hatch further notes that each GT start subjects major components to significant thermal and mechanical stress. Given the emergency and peaking operating role of the Hardwoods facility, continued operation requires careful consideration of start-based maintenance intervals, spare parts availability, and potential extended outage risk.

Hatch notes that the unit is operating with an elevated risk profile, and its ability to operate as required for a prolonged period, such as in the event of an extended Labrador-Island Link ("LIL") bipole outage, is at risk as its availability cannot be assured.

In addition, Hardwoods has significant synchronous condensing requirements. Hatch developed the sustaining capital plan using an assumed operating profile of 80 starts per year per engine, 230 generating operating hours per year, and approximately 5,900 synchronous condensing operating hours per year, based on Hatch's review of Hydro's operational data.

3.2.2 Sustaining Capital and Operating Plan

Hatch prepared sustaining capital profiles for continued operation of the Hardwoods GT through potential retirement years of 2035 and 2040. These profiles include capital upgrades, plant upgrades or modifications, routine and major maintenance, GT overhaul requirements, and repetition of unplanned maintenance items based on historical age-related deterioration.

For Hardwoods, Hatch recommends that sustaining capital planning assume a GT overhaul approximately every four years for each engine based on the expected operating profile of 80 starts per year per engine and an overhaul interval of approximately 300 to 350 starts, consistent with Hydro's operating experience.

The primary service provider for the Olympus fleet, Sulzer, advised that 2040 should be considered the latest practical retirement date for the Rolls-Royce Olympus CT fleet due to declining global fleet size and increasing challenges associated with long-term parts and service support.

Hatch's capital and operating forecast for operation through 2035 and 2040 for the Hardwoods GT is presented in Figure 1.

Case		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Total
HWD 2035	Capital	304	4,587	6,046	4,260	938	3,172	-	3,366	127	-	-	-	-	-	-	-	$22,799
	Operating	520	536	552	568	585	603	621	640	659	678	699	-	-	-	-	-	$6,660
	Total	**824**	**5,122**	**6,597**	**4,828**	**1,523**	**3,775**	**621**	**4,005**	**785**	**678**	**699**	**-**	**-**	**-**	**-**	**-**	**$29,459**
HWD 2040	Capital	304	4,587	6,046	4,260	938	3,578	-	3,981	127	3,605	341	3,997	635	4,501	-	-	$36,899
	Operating	520	536	552	568	585	603	621	640	659	678	699	720	741	764	787	810	$10,482
	Total	**824**	**5,122**	**6,597**	**4,828**	**1,523**	**4,181**	**621**	**4,620**	**785**	**4,283**	**1,040**	**4,717**	**1,377**	**5,265**	**787**	**810**	**$47,380**

Figure 1: Hardwoods GT Capital and Operating Forecast

The Hardwoods sustaining capital forecast identifies total capital and operating costs of approximately $29.5 million for retirement in 2035, consisting of approximately $22.8 million in capital costs and $6.7 million in operating costs. For continued operation to 2040, the total forecast increases to approximately $47.4 million, consisting of approximately $36.9 million in capital costs and $10.5 million in operating costs. These costs are presented in 2025 dollars, escalated at 3% annually in the forecast.

3.3 Stephenville Gas Turbine

3.3.1 Condition Assessment and Findings

Like the Hardwoods GT, the Stephenville GT provides standby generation and reactive power support as a synchronous condenser. Hatch notes that supply to the Stephenville area is also primarily fed through one transmission line corridor, creating a single point of vulnerability. In the event of a transmission failure, the Stephenville facility must be capable of immediate operation; in the event of a catastrophic event such as severe freezing rain or forest fire, sustained operation may be required.

As with Hardwoods, Hatch identified that the Stephenville GT units are operating well beyond their original design life. The facility appears to remain in reasonable condition; however, its advanced age creates increasing risk associated with degradation, equipment obsolescence, and future parts and service support.

The Stephenville operating profile is less demanding than Hardwoods, with fewer starts and lower generating operating hours. Hatch developed the sustaining capital plan using an assumed operating profile of 40 starts per year per engine, 125 generating operating hours per year, and approximately 3,800 synchronous condensing operating hours per year.

Although the annual operating profile is lower than Hardwoods, Hatch indicates that continued reliance on the Olympus GT technology remains subject to the same broader fleet risks, including declining supportability, single-source service provider dependency, and uncertainty regarding performance during extended emergency operation. Hatch notes that the unit is operating with an elevated risk profile, and its ability to operate as required for a prolonged period, such as in the event of an extended LIL bipole outage, is at risk as its availability cannot be assured.

3.3.2 Sustaining Capital and Operating Plan

Hatch prepared sustaining capital profiles for continued operation of the Stephenville GT through potential retirement years of 2035 and 2040. As with the Hardwoods GT, these profiles include capital upgrades, plant upgrades or modifications, routine and major maintenance, GT overhaul requirements, and repetition of unplanned maintenance items based on historical age-related deterioration.

For Stephenville, Hatch recommends that sustaining capital planning assume a GT overhaul approximately every eight years for each engine, based on the expected operating profile of 40 starts per year per engine and an overhaul interval of approximately 300 to 350 starts.

Hatch's capital and operating forecast for operation through 2035 and 2040 for the Stephenville GT is presented in Figure 2.

Case		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Total
SVL 2035	Capital	450	6426	4051	546	1197	908	398	410	-	-	-	-	-	-	-	-	$14,385
	Operating	520	536	552	568	585	603	621	640	659	678	699	-	-	-	-	-	$6,660
	Total	**970**	**6,962**	**4,602**	**1,115**	**1,782**	**1,511**	**1,019**	**1,049**	**659**	**678**	**699**	-	-	-	-	-	**$21,045**
SVL 2040	Capital	450	6426	4051	546	1197	908	398	1024	-	3571	4047	710	664	-	-	-	$23,992
	Operating	520	536	552	568	585	603	621	640	659	678	699	720	741	764	787	810	$10,482
	Total	**970**	**6,962**	**4,602**	**1,115**	**1,782**	**1,511**	**1,019**	**1,664**	**659**	**4,249**	**4,746**	**1,430**	**1,406**	**764**	**787**	**810**	**$34,474**

Figure 2: Stephenville GT Capital and Operating Forecast

The Stephenville sustaining capital forecast identifies total capital and operating costs of approximately $21.0 million for retirement in 2035, consisting of approximately $14.4 million in capital costs and $6.7 million in operating costs. For continued operation to 2040, the total forecast increases to approximately $34.5 million, consisting of approximately $24.0 million in capital costs and $10.5 million in operating costs. These costs are presented in 2025 dollars, escalated at 3% annually in the forecast.

3.4 Retirement Recommendations

Hatch concludes that both Hardwoods and Stephenville are operating well beyond their original design lives and that, although the facilities currently appear to be in reasonable condition, their advanced age creates an elevated risk profile.[6] The ability of the facilities to operate dependably under high-stress or extended runtime scenarios, including prolonged LIL outage conditions or extreme weather events, cannot be assured.

Hatch recommends that Hardwoods be retired as soon as practicable and potentially replaced with new GT generating units if system requirements continue to require generation and synchronous condensing capability at the Hardwoods terminal station location. Hatch further recommends that, following Hardwoods retirement, the Hardwoods GT generating units and other plant components may be preserved as spare parts support for continued operation of Stephenville.

Hatch recommends that Stephenville be considered for retirement and/or replacement in 2040. Hatch identifies 2035 as the earliest practical year in which a replacement project could be completed, considering current capital project workload and typical project development timelines, while Sulzer recommends that operators of the Rolls-Royce Olympus GT generators consider 2040 as the latest retirement year in planning for continued support.

Hydro will evaluate the reasonableness of continued operation of these units to meet supply requirements within its next RRA Study update, as an option to meet the Reference Case requirements. While Hatch recommends that Hardwoods be retired by 2035 or as soon as practicable, with remaining serviceable components to be utilized to maintain Stephenville to 2040, Hatch provided cost estimates for extension for both sites to 2035 and 2040. Hydro will consider the reliability and locations of the units, and specific system requirements, when assessing the optimal retirement timeline for these units.[7]

These recommendations are based solely on the assessed condition of the individual assets and do not consider wider Hydro system needs, reliability requirements, or system cost impacts. Hydro will

[6] Hydro applies a forced outage rate of 30% for both assets.
[7] Retirement of Hardwoods and Stephenville may also necessitate further assessment of localized transmission impacts such as transformer loading, which are assessed through Hydro's annual transmission assessments.

consider these findings as part of its broader system planning activities in consideration of the RRA Study and planning for the Reference Case requirements.

3.5 Considerations for Resource Planning

Hatch's findings with regards to life extension of Hardwoods and Stephenville provide valuable input for use in Hydro's resource planning, including expansion plan, reliability, and shortfall modelling. While Hatch has provided costing through 2035 and 2040 for each unit, they also raise concern regarding the reliability and availability of these units for prolonged operation, such as in the event of an extended LIL bipole outage.

Hydro currently utilizes a Derated Adjusted Utilization Forced Outage Probability ("DAUFOP") of 30% for the Hardwoods and Stephenville GTs for reliability and resource planning, based on analysis of historical performance. As Hatch notes that these units are well beyond their intended useful life, and consistent with the bathtub curve model of the asset life cycle, Hydro believes it is reasonable to expect that unit reliability performance can be expected to decrease with continued operation.[8] Furthermore, Hydro believes that consideration must be given to unit reliability during a prolonged period of need, such as during an extended LIL bipole outage, whereby the units could be subjected to a high number of starts and stops through a relatively short period. While assessment of DAUFOP rates is outside of the scope of this study, Hydro is conducting further study to establish reasonable DAUFOP assumptions and sensitivity cases, as well as appropriate allowances for in-service failures that reflect unit reliability, for use in modelling the potential extension or retirement of these units in future planning assessments.

4.0 Combustion Turbine Replacement Study

4.1 Replacement Technology Review

The CT Replacement Study Cost Estimate, provided as Attachment 2, developed AACE[9] Class 5 capital cost estimates for replacement GT generating units capable of meeting the capacity and synchronous condensing requirements at each GT location.

Hatch contacted General Electric ("GE"), Siemens, Solar Turbines, and Mitsubishi Heavy Industries to obtain technical information on GT generator options capable of meeting Hydro's functional,

[8] The Bathtub Curve model predicts asset failure rates through the life of an asset, predicting higher rates of failure during the early and later years of the asset life cycle.
[9] Association for the Advancement of Cost Engineering ("AACE").

operational, and environmental requirements. The key requirements included approximately 50 MW of nominal capacity, diesel operation with future fuel flexibility, synchronous condensing capability, single-ended configuration, quick-start capability to full load within approximately 10 minutes, and reliable operation at minimum load of 5 MW.

Hatch reviewed both aeroderivative and industrial GT options. Aeroderivative units generally provide compact footprints, high simple-cycle efficiency, rapid start capability, and strong load-following performance, making them well suited to peaking, backup, and emergency operation. Industrial units may offer lower capital cost on a dollar-per-megawatt basis and reduced maintenance frequency but are generally less optimized for frequent cycling and can require longer outage durations for major maintenance.

Based on the options offered, Hatch selected the GE LM6000 aeroderivative GT and the Solar Titan 350 industrial GT as the basis for replacement cost development. Hatch notes that the GE LM6000 was the only evaluated unit that satisfied all preferred criteria identified for the replacement study.

4.2 Synchronous Condensing Considerations

Synchronous condensing capability is a consideration in the replacement study. Hatch notes that both existing facilities currently provide grid support through extended synchronous condensing operation. Hatch notes expected annual synchronous condensing operation of approximately 5,900 hours at Hardwoods and approximately 3,800 hours at Stephenville.[10]

Hatch assessed clutched and non-clutched synchronous condensing configurations. In a clutch-based configuration, the generator can remain synchronized to the grid and continue providing inertia, reactive power, short-circuit support, and voltage support after the GT is shut down and mechanically disengaged. The availability of these features would provide significant transmission system benefits and support system stability when considering conditions, particularly when synchronous generation is reduced and asynchronous generation from assets such as the LIL or potential future wind generation is elevated.

[10] Hydro notes that this projection is appropriate for the near-term but could be subject to change once additional generation is brought online or assets are retired. For example, new generation, such as the proposed CTs on the Avalon Peninsula, would be specified to include synchronous condenser functionality. In parallel, Hydro is assessing the continued requirement and effectiveness of synchronous condenser capability from Unit 3 at the Holyrood Thermal Generating Station.

Hatch concluded that clutch-based synchronous condensing configurations are preferred. Non-clutched configurations result in higher parasitic losses because the power turbine continues rotating after GT shutdown. Given the anticipated annual synchronous condensing hours, Hatch concluded that non-clutched operation would be unsuitable for regular or extended synchronous condensing service.

4.3 Conceptual Replacement Configurations

Hatch evaluated two conceptual replacement configurations: a single aeroderivative GT unit based on a 1 x 50 MW GE LM6000 configuration and a dual-unit industrial GT configuration based on a 2 x 25 MW Solar Titan 350 arrangement, ultimately recommending the aeroderivative option for Hydro’s use case.

The conceptual layouts considered the existing Hardwoods and Stephenville sites and assumed reuse of certain existing site assets, including the fuel unloading system, fuel storage, operator facilities, maintenance buildings, terminal station, back-up generator, stormwater infrastructure, fencing, roads, access, and parking areas.

The replacement concepts include new facilities and assets such as a GT building, fuel forwarding and heating systems, demineralized water treatment, GT lube oil and cooling systems, a control building, generator step-up transformer, low-voltage electrical systems, motor control centres, station batteries, and uninterruptible power supply systems.

Hatch also reviewed existing fuel storage capacity and future fuel considerations, including potential fuel capacity expansion, biofuel conversion, and future hydrogen or hydrogen-blend conversion, excluding delivery and storage infrastructure.

4.4 Class 5 Cost Estimates

Hatch developed AACE Class 5 cost estimates for both replacement configurations. The estimates carry an expected accuracy range of +30% to +100% and -20% to -50% and include costs associated with engineering, design, and construction completion. The estimates exclude decommissioning and removal of the existing GT units and associated auxiliaries.

Hatch evaluated a 1 x 50 MW configuration based on the GE LM6000 and estimated total project capital expenditures of approximately $256.3 million CAD in 2025 dollars. The estimated capital costs include direct costs, indirect costs, owner's costs, interest during construction, and contingency.[11]

Hatch recommends that, should Hydro decide to pursue replacement of the GT units, the next step would be a Concept Study to further define the replacement concepts and develop an AACE Class 4 estimate, followed by a Front-End Engineering Design Study to support investment decisions and improve capital cost certainty.

Hydro notes that in the time since Hatch developed these estimates, the CT market has continued to experience significant market pressure and increasing lead times, with industry intelligence indicating CT cost increases of over 50% between October 2025 and March 2026; actual CT replacement costs could approach the upper range of the Class 5 estimate accuracy.[12]

5.0 Conclusion and Next Steps

The enclosed Studies provide Hydro with an updated independent assessment of the condition, remaining useful life, operational risks, sustaining capital requirements, retirement considerations, and potential replacement options associated with the Hardwoods and Stephenville generating stations.

The studies identify that both facilities are operating significantly beyond their original design lives and face increasing reliability, obsolescence, and long-term maintainability risks.

While Hatch recommends retirement and/or replacement of Hardwoods as soon as practicable, targeting retirement in 2035, and consideration of retirement and/or replacement of Stephenville in 2040, based on asset condition and supportability considerations, these recommendations do not consider wider system needs, reliability planning requirements, or system cost impacts. Hydro will evaluate the reasonableness of continued operation of these units to meet supply requirements within its next RRA Study update, as an option to meet the Reference Case requirements, and in its future transmission planning assessments.

[11] Hatch's estimate was completed in advance of procurement of the Avalon CT package. Discrepancies between Hatch's estimate and Hydro's recent CT procurement costs are primarily attributed to the passage of time and the level of estimate maturity.

[12] Noble, B. "5-Year Waits and Rising Costs: How Demand is Redefining the Gas Turbine Market," Utility Dive, March 23, 2026, https://www.utilitydive.com/news/5-year-waits-and-rising-costs-how-demand-is-redefining-the-gas-turbine-mar/813385/.

The replacement study provides conceptual replacement pathways and indicative Class 5 cost estimates to support future planning activities. The reports do not constitute a recommendation for a specific replacement project or technology selection at this time.

Hydro will consider the results of these studies alongside its broader reliability planning, resource adequacy analysis, and system expansion planning activities. The findings of these reports will be utilized as inputs into Hydro's next RRA Study update when considering the best options to meet the Reference Case requirements.

Attachment 1

Condition Assessment and Retirement Optimization Study

newfoundland labrador hydro

Report

Condition Assessment and Retirement Optimization Study

H375814-0000-210-066-0001

PROVINCE OF NEWFOUNDLAND
PEG Newfoundland and Labrador PROFESSIONAL ENGINEERS AND GEOSCIENTISTS
PERMIT HOLDER
CLASS "A"
This Permit Allows
HATCH LTD.
06735
To practice Professional Engineering in Newfoundland and Labrador
Permit No. as issued by PEG-NL D0090
which is valid for the year 2026

LICENSED PROFESSIONAL ENGINEER
08879
G. D. COOPER
SIGNATURE
2026-04-29
DATE
NEWFOUNDLAND & LABRADOR

			D. Cooper	Ghantous, Tia	DeYoung, Scot
2026-04-27	1	Approved for Use	G. Cooper	T. Ghantous	S. DeYoung
2026-03-18	0	Approved for Use	G. Cooper	T. Ghantous	S. DeYoung
DATE	**REV.**	**STATUS**	**PREPARED BY**	**CHECKED BY**	**APPROVED BY**

HATCH

IMPORTANT NOTICE TO READER

This report, including the assessment contained herein, has been prepared by Hatch Ltd. ("Hatch") for the sole and exclusive use of Newfoundland and Labrador Hydro (the "Client") for the purpose of assisting the management of the Client in making decisions with respect to the remaining operating life of the Stephenville and Hardwood Power Stations (the "Assets") and retirement and replacement planning. Any use of or reliance upon this report by another person is done at their sole risk and Hatch does not accept any responsibility or liability in connection with that person's use or reliance.

This report contains the expression of the opinion of Hatch using its professional judgment and reasonable care based upon information available and conditions existing at the time of preparation of this report, and information made available to Hatch by the Client or by certain other parties on behalf of the Client (the "Client or Other Information").

The use of or reliance upon this report is subject to the following:

1. This report is to be read in the context of and is subject to the terms of the relevant Proposal P086697 between Hatch and the Client (the "Agreement"), including any methodologies, procedures, techniques, assumptions, and other relevant terms or conditions specified in the Hatch Agreement.
2. This report, including the assessment contained herein, is meant to be read as a whole, and sections of the report must not be read or relied upon out of context.
3. Unless expressly stated otherwise in this report, Hatch has not verified the accuracy, completeness, or validity of any information provided to Hatch by or on behalf of the Client and Hatch does not accept any liability in connection with such information.
4. The condition, stability and safety of the facilities has been assessed based on the data available on or before June 2025 and may change over time (or may have already changed) due to natural forces or human intervention, and Hatch does not accept any responsibility for the impact that such changes may have on the accuracy or validity of the opinions, conclusions, and recommendations set out in this report.

Table of Contents

1. Executive Summary 1

1.1 HWD and SVL Operating History Review 1
1.2 Operation Requirements 1
1.3 Recommendation 2

2. Introduction 3

2.1 Part A: Document Review 3
2.2 Part B: Condition Assessment 3
2.3 Part C: Sustaining Capital Plan 4
2.4 Part D: Combustion Turbine Replacement Study 4

3. Power Plant Descriptions 5

3.1 Hardwoods (HWD) Power Plant Description 5
3.2 Stephenville (SVL) Power Plant Description 8

4. Combustion Turbine Review 10

4.1 Overhaul and Maintenance History 10
4.2 Recommendation 13

5. Control System Review 14

5.1 Hardwoods 14
5.2 Stephenville 16

6. Electrical System Review 19

6.1 Hardwoods Electrical System 19
6.2 Stephenville Electrical System 21

7. Major Upgrades 22

7.1 Hardwoods Major Upgrades 22
7.2 Stephenville Major Upgrades 23

8. Condition Assessment 24

8.1 Boundaries 24
8.2 Asset Grading 24
8.3 Hardwoods 25
8.4 Stephenville 27

9. Sustaining Capital and Operating Plan Forecast and Retirement Optimization 29

9.1 Hardwoods (HWD) Sustaining Capital Plan 30
9.2 Stephenville (SVL) Sustaining Capital Plan.. 42
9.3 Recommended Capital Spares.. 52
9.4 Retirement 53

10. Conclusion and Recommendations 55

List of Tables

Table 4-1: Operating Hours (2010-2025).. 10
Table 4-2: CT Engine Overhaul History.. 10
Table 4-3: Combustion Turbine Engine Positions 11
Table 7-1: HWD Historical Major Upgrades ($1000’s).. 22
Table 7-2: SVL Historical Major Upgrades ($1000’s) 23
Table 8-1: Asset Grading Scale 25
Table 8-2: HWD Power Block Grading 25
Table 8-3: HWD I&C Asset Grading 26
Table 8-4: HWD Electrical Asset Grading.. 26
Table 8-5: HWD Fuel Oil Asset Grading 26
Table 8-6: HWD Glycol Cooling Asset Grading 27
Table 8-7: HWD Support Buildings Asset Grading 27
Table 8-8: SVL Power Block Grading 27
Table 8-9: SVL I&C Asset Grading 28
Table 8-10: SVL Electrical Asset Grading.. 28
Table 8-11: SVL Fuel Oil Asset Grading.. 28
Table 8-12: SVL Glycol Cooling Asset Grading.. 28
Table 8-13: SVL Support Buildings Asset Grading.. 28
Table 9-1: HWD Summary of Costs by Scenario ($1000’s) 31
Table 9-2: SVL Summary of Costs by Scenario ($1000’s) 43
Table 9-3: Recommended Additional Capital Spares.. 52
Table 9-4: HWD, and SVL Cumulative Capital and Operating Costs ($1000’s from 2030 to 2040) 53

List of Figures

Figure 3-1: Hardwoods Combustion Turbine Power Plant 5
Figure 3-2: Stephenville Combustion Turbine Power Plant.. 8

List of Appendices

Appendix A Sustaining Capital and OPEX Cost Summary

- A.1 Hardwoods Retirement in 2035
- A.2 Hardwoods Retirement in 2040
- A.3 Stephenville Retirement in 2035
- A.4 Stephenville Retirement in 2040

Appendix B Document Register

Appendix C Motor Control Center Quotations Received

Appendix D ABB 2021 Lifecycle Plan Listings for Parts and Service Support Status for Key Control System Components

- D.1 Hardwoods ABB 2021 Lifecycle Plan Listing for Parts and Service Support Status for Key Control System Components
- D.2 Stephenville ABB 2021 Lifecycle Plan Listing for Parts and Service Support Status for Key Control System Components

1. Executive Summary

The Hardwoods (HWD) and Stephenville (SVL) Generating Stations have been in operation since 1976 and 1975. Each station consists of two 25 MW Rolls Royce Olympus C-type 2022 combustion turbines, coupled via SSS clutches to a Curtiss-Wright power turbine and a shared 63,341 kVA Brush generator. These stations provide backup and emergency power and operate as synchronous condensers to support grid stability.

1.1 HWD and SVL Operating History Review

Originally designed for a service life of 20-25 years, both stations have now exceeded 50 years in operation. Despite being reasonably well maintained, the aging infrastructure presents increasing operational and reliability risks.

In 2022, Hatch conducted a Viability Assessment examining life extension scenarios of 2, 5, and 10 years, along with the associated capital investments required to sustain operations. A key concern identified is the obsolescence of the Rolls Royce Olympus combustion turbines, which ceased production in the early 2000s and no longer receive OEM support. As a result, maintaining these units has become increasingly difficult. Currently, Sulzer - following its acquisition of Alba - is the sole service provider available to Newfoundland and Labrador Hydro (NL Hydro), creating a single point of dependency for both parts and maintenance. In cases where replacement parts are unavailable, manufacturing lead times can extend up to nine months, posing a significant risk to operational readiness.

Recent operational challenges further highlight these concerns. Over the past 15 years, the average operating time between overhauls has been approximately 500 hours with an average 330 starts, and instances of failure occurring after as few as 30 hours of operation. This trend is expected to persist if the engines remain in service. Given the equipment’s advanced age, absence of OEM support, and escalating risk of failure, a strategic decision is required regarding the retirement and replacement of these facilities. This study aims to identify the optimal timeline for decommissioning the existing assets and potentially replacing the combustion turbine units with modern, reliable combustion turbine generating units to ensure continued grid support and emergency response capability.

1.2 Operation Requirements

The power plants have two modes of operation:

- Backup and emergency power generation;
- Synchronous condensing operation.

The primary function and operation of each power plant is further described below.

1.2.1 Hardwoods Power Plant

The function of the HWD power plant is to provide backup and emergency power, and synchronous condensing services. The St. John's electrical supply is primarily fed through one transmission line from Holyrood and two additional lines from Soldiers Pond. All three lines run through the same transmission corridor, creating a single point of vulnerability. In the event of a transmission line failure, the HWD power plant must be capable of immediate operation to maintain system stability. In the case of a catastrophic event - such as severe freezing rain or a forest fire - the outage could be prolonged, requiring sustained operation of the HWD power plant.

1.2.2 Stephenville Power Plant

The primary function of the SVL power plant is to provide backup and emergency power, and synchronous condensing services. The Stephenville electrical supply is primarily fed through one transmission line through a single transmission corridor, creating a single point of vulnerability. In the event of a transmission line failure, the SVL power plant must be capable of immediate operation. In the case of a catastrophic event-such as severe freezing rain or a forest fire - the outage could be prolonged, requiring sustained operation of the SVL power plant.

1.3 Recommendation

The combustion turbine generating units at the HWD and SVL power plants are operating well beyond their original design life. Although they currently appear to be in reasonable condition, their advanced age introduces a heightened risk of component failure due to degradation mechanisms such as creep, fatigue, and material embrittlement. Given this elevated risk profile, the capability of each power plant to operate dependably in the event of a prolonged outage of the Labrador-Island Link is assessed to be at risk, particularly during prolonged outages of the Labrador-Island Link or in extreme conditions such as a heat wave, forest fires or freezing rain. Their availability under high stress or extended runtime scenarios cannot be assured.

It is recommended that the HWD power plant be retired in 2035 and potentially be replaced with new combustion turbine generating units should the system requirements continue to require generating and synchronous condensing capabilities at the HWD substation location. Following retirement, the HWD combustion turbine generating units and other plant components may be preserved in storage as spare parts support for operation of the SVL power plant until 2040 at which time retirement and/or replacement of the SVL power plant should also be considered. These recommendations are based solely on the assessed condition of the individual assets and do not consider the wider NL Hydro system needs and cost impacts.

2. Introduction

Newfoundland and Labrador Hydro (NL Hydro) requires a plan to retire or replace the Hardwoods (HWD) and Stephenville (SVL) 50 MW Generating Stations. The objective of this work is to determine the remaining useful life and optimal retirement date for the HWD and SVL power plants and estimate the capital and operating costs expected to reliably operate the plants until retirement. The work provides an independent assessment of the condition of the HWD and SVL stations to determine the capital requirements for the facilities to continue operation until retirement.

The scope of work completed through the methodology outlined in this section adheres to the requirements of the RFP.

2.1 Part A: Document Review

Design documents and historical records including the plant design documents, operational history, plant performance and availability, major maintenance, and major overhauls performed on plant equipment were reviewed.

The key documents used for this study are listed below:

- HWD and SVL Operating Hours 2010-2025;
- HWD and SVL Major Upgrades;
- HWD and SVL Preventative Maintenance Documentation.

Appendix B includes a complete listing of documentation used as a basis for this study.

2.2 Part B: Condition Assessment

Site visits were attended at the HWD and SVL power plants in April and May of 2025 by Hatch mechanical, electrical and structural engineering team members to assess the visual condition of the power plants and discuss their operating and maintenance status with the operations team. During the site visits the following systems were reviewed:

- Combustion turbine engines (including intake and exhaust ducts, enclosures, cooling systems, etc.);
- Generators (including exciters and couplings);
- Fuel supply piping (including valves and pipe supports);
- Lube oil systems (including pumps, storage tanks, piping, coolers, etc.);
- Compressed air system (including receivers, dryers, piping);
- Switch gear, breakers, and controls systems;
- Black start diesel generator systems;
- Fire suppression systems;
- Buildings/facilities.

The site visit assessment was visual and non-intrusive to assess a condition overview only and did not include assessment of internal components.

2.3 Part C: Sustaining Capital Plan

The sustaining capital forecasts provided with this report are developed considering:

- Assessed condition rating;
- Most recent inspection and repair history;
- Combustion turbine operating hours and starts per year;
- Repairs identified to be required based on the document review, site visit findings, and discussions with the NL Hydro operations team;
- Repairs required during the remaining operating life of the station;
- Typical asset life.

Historical costs have been used with escalation factors to support sustaining capital plan and operating cost forecast development.

2.4 Part D: Combustion Turbine Replacement Study

This study has developed cost estimates for the installation and commissioning of new combustion turbine generating units at each site which are provided in the replacement cost study report document H375814-0000-100-066-0002. The study has considered the condition of assets and sub-systems at each power plant site which may be repurposed to support the new generating capacity.

3. Power Plant Descriptions

3.1 Hardwoods (HWD) Power Plant Description

The HWD power plant is a 50 MW simple cycle combustion turbine generating station located within a terminal station consisting of 66 kV and 230 kV bus work, transformers, circuit breakers, and transmission lines. The combustion turbine generator output voltage of 13.8 kV is connected via an enclosed bus duct to a circuit breaker located in a switchgear assembly.

The HWD power plant began service in 1976 and operates as both a generator for backup and emergency power and as a synchronous condenser.

Figure 3-1: Hardwoods Combustion Turbine Power Plant

3.1.1 Combustion Turbine

The HWD power plant consists of two Rolls Royce Olympus C type 2022 Combustion Turbine (CT) Engines (A&B) which operate on #2 fuel oil.

3.1.2 Power Turbine

Each CT drives a Curtis Wright Power Turbine equipped with a SSS size 208T clutch.

3.1.3 Generator

The generator is a 63,341 kVA 13.8 kV Brush generator and is common to the two power turbines. The generator can be driven by both power turbines in tandem, or either power turbine separately as required by operations. The generator has a rotating exciter connected to the shaft. Fan blades on the generator shaft induces filtered outside air through the stator and rotor providing cooling air to the generator.

3.1.4 Main Lube Oil System (MLO)

Each of the power turbines, clutches, and the generator share a common lube oil system. The lube oil system is cooled by a lube oil to glycol shell and tube heat exchanger, and an external glycol to air fin-fan heat exchanger. The glycol absorbs lube oil heat from the shell and tube heat exchanger and rejects heat to air through the air-cooled fin-fan heat exchanger.

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 located in the Auxiliary Module Building which contains the lube oil storage and pump systems.

3.1.5 Fuel Oil System

The Fuel Oil System consists of a fuel truck unloading pump set located in a fuel oil unloading building at the storage tank area, one 2,226,000 L fuel oil storage tank, and a piping system between the storage tank and the fuel forwarding pump sets. Both AC and DC fuel pumps are located in a dedicated fuel forwarding building.

3.1.6 Instrumentation and Control Systems

The Distributed Control System (DCS) is a ELSAG Bailey INFI 90 Distributed Control System (DCS) located within the Control Building. It provides process control, human machine interface (HMI), and monitoring functions for the HWD power plant. The combustion turbine can also be remotely started, stopped, and monitored from the Energy Control Centre located in St. John’s using a Supervisory Control and Data Acquisition (SCADA) system.

3.1.7 Electrical Systems

The electrical system consists of a 13.8 kV switchgear assembly housed in an outdoor enclosure. An enclosed bus duct connects the generator to its circuit breaker and a 13.8/66 kV step-up transformer.

The Control Building houses motor control centers, protection and control devises, a battery charger, and an inverter. The 125 V DC batteries are installed in a battery room within the Control Building.

3.1.8 Support Buildings

The power plant layout includes the following support structures; Control Building, Fuel Unloading Building, Fuel Forwarding Building, Auxiliary Module Building, Maintenance and Parts Storage Building, High Voltage Switchgear Building, and Blackstart Emergency Diesel Generator Building.

3.2 Stephenville (SVL) Power Plant Description

The Stephenville (SVL) Power Plant is a 50 MW simple cycle combustion turbine generating station located within a terminal station consisting of 66 kV and 230 kV bus work, transformers, circuit breakers, and transmission lines. The combustion turbine generator output voltage of 13.8 kV is connected via an enclosed bus duct to a circuit breaker located in a switchgear assembly.

The SVL power plant began service in 1975 and operates as both a generator for backup and emergency power and as a synchronous condenser.

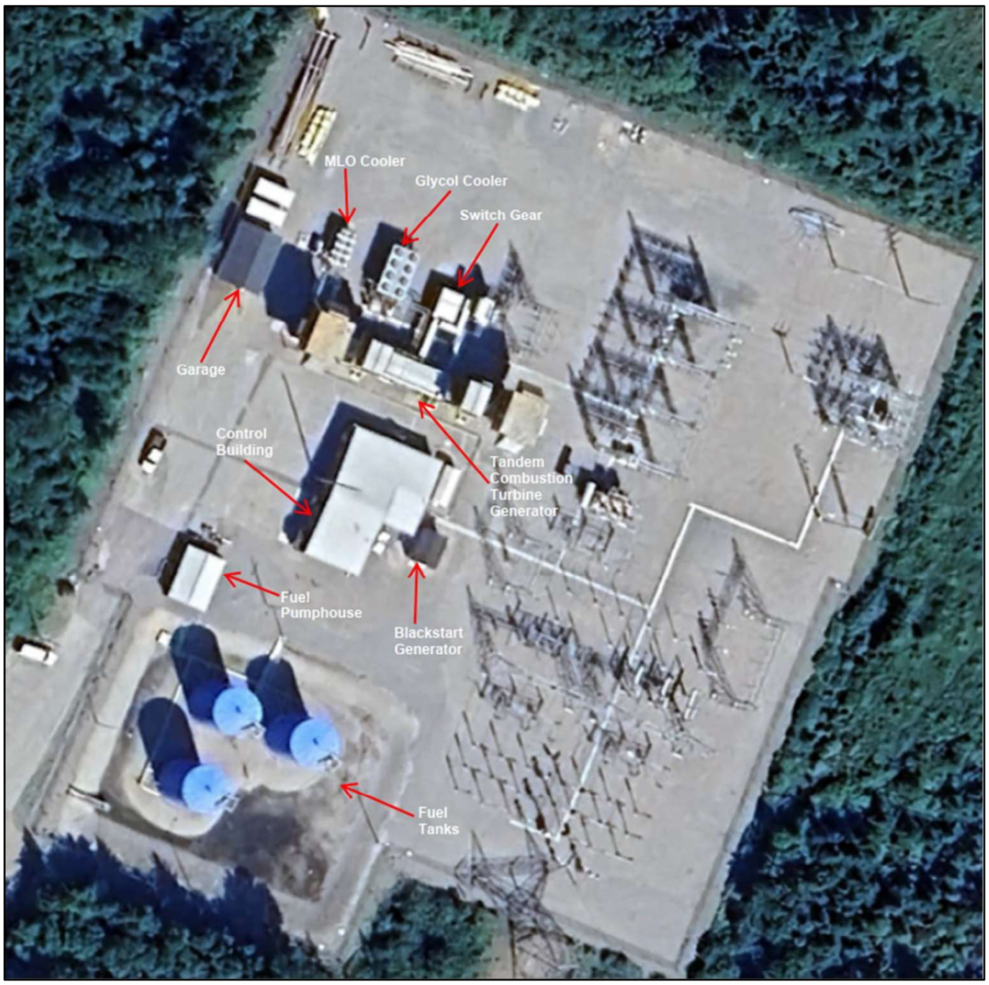


Figure 3-2: Stephenville Combustion Turbine Power Plant

3.2.1 Combustion Turbine

The power plant consists of two Rolls Royce Olympus C type 2022 Combustion Turbine (CT) Engines (A&B) which operate on #2 fuel oil.

3.2.2 Power Turbine

Each CT drives a Curtis Wright Power Turbine equipped with a SSS size 170T clutch.

3.2.3 Generator

The generator is a 63,341 kVA 13.8 kV Brush generator and is common to the two power turbines. The generator can be driven by both power turbines in tandem, or either power turbine separately as required by operations. The generator has a rotating exciter connected to the shaft.

The generator is cooled by a 50/50 glycol water mixture which absorbs heat from the generator casing and discharges heat to atmosphere though a fin-fan cooler.

3.2.4 Main Lube Oil System (MLO)

Each of the power turbines, clutches, and the generator share a common lube oil system. The lube oil system is cooled by an external glycol to air fin fan heat exchanger.

The Glycol Cooling System for the main lube oil system consists of a fin fan air cooled heat exchanger and a glycol circulation pump with a three-way temperature control valve. The glycol cooler is located outdoors.

3.2.5 Fuel Oil System

The fuel oil system includes a fuel truck unloading facility with fuel unloading pumps, three 477,000 L fuel oil storage tanks, and fuel forwarding pumps located within the Fuel Forwarding Building.

3.2.6 Instrumentation and Control Systems

The Distributed Control System (DCS) is a ELSAG Bailey INFI 90 Distributed Control System (DCS) located within the Control Building. It provides process control, human machine interface (HMI), and monitoring functions for the HWD power plant. The combustion turbine can also be remotely started, stopped, and monitored from the Energy Control Centre located in St. John’s using a Supervisory Control and Data Acquisition (SCADA) system.

3.2.7 Electrical Systems

The electrical system consists of a 13.8 kV switchgear assembly housed in an outdoor enclosure. An enclosed bus duct connects the generator to its circuit breaker and a 13.8/66 kV step-up transformer.

The Control Building houses motor control centers, protection and control devices, battery chargers, 250 V and 125 V batteries, and an inverter.

3.2.8 Support Buildings

The SVL power plant layout includes the following support buildings; Control Building, Fuel Forwarding Building, Parts Storage Shed, Waste Oil Storage Shed, and Black start Emergency Diesel Generator Building.

4. Combustion Turbine Review

4.1 Overhaul and Maintenance History

The combined HWD and SVL combustion turbine fleet currently consists of four (4) installed combustion turbine engines with one (1) spare engine. Two (2) combustion turbine engines and power turbines are installed at each site driving a common tandem generator.

Table 4-1 includes the operating hours in generation and synchronous condensing modes for each station for the period of 2010 to 2025, and the power plant availability over this period considering both planned and forced outage hours.

Table 4-1: Operating Hours (2010-2025)

Unit	Generating Hours	Average Annual Generating Hours	Synchronous Condensing Hours	Average Annual Synchronous Condensing Hours	Availability (%)
HWD CT	3,445	230	89,165	5,944	87
SVL CT	1,842	123	57,083	3,806	73

Table 4-2 below summarizes the overhaul history of each engine since 2012. The need to initiate an overhaul is generally determined by deficiencies identified during regular inspections. Engine 202420 has been recently purchased and is currently undergoing an overhaul. When the overhaul is complete and the engine is delivered to NL Hydro it will be maintained as a rotational spare to limit the outage times experienced at HWD and SVL in the event of an engine failure or when inspection-based overhauls are identified to be required. The engine is advised to be suitable as a spare engine for installation at either of the A and B engine positions in the tandem combustion turbine generator installations at both the HWD and SVL power plants.

Table 4-2: CT Engine Overhaul History

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Serial #														
202204			OH		R			R						
202205					R								R	
202420														OH
202223	OH		OH					OH	WR					
202224		OH		OH		OH								

OH – Overhaul

R - Repair

WR- Warranty Repair

Between HWD and SVL there has been a total of eleven CT overhauls which equate to an average overhaul interval of 330 starts and only 500 running hrs. The current positions of the combustion turbine engines are summarized in table Table 4-3.

Table 4-3: Combustion Turbine Engine Positions

Serial #	Location
202204	Stephenville Unit B
202205	Hardwoods Unit A
202420	Spare (in progress of overhaul at Sulzer facility)
202223	Hardwoods Unit B
202224	Stephenville Unit A

The combustion turbine overhaul and repair works performed within the last 10 years are summarized below based on the maintenance history information provided.

4.1.1 Engine # 202204

- 2014 – Overhaul. The engine was removed and shipped to Scotland where it was stripped, inspected and overhauled by Alba and deemed fit for service;
- 2016 – LP rotor main line bearing failure. The engine was removed and shipped to Scotland where it was stripped, inspected and repaired by Alba and reinstalled in 2017;
- 2019 – HP turbine blade detachment. The engine was removed and shipped to Scotland where it was stripped, inspected and repaired by Alba and deemed fit for service.

4.1.2 Engine # 202205

- 2016 – Two months following a Dec 2015 borescope inspection the engine experienced a shut down and was found with significant damage to the combustion cans. Engine # 202205 was removed and shipped to Scotland where it was stripped, inspected and repaired by Alba and deemed fit for service. Leased combustion turbine 202040 was installed;
- 2024 – Nozzle Guide Vane (NGV) loss observed during a scheduled borescope inspection. The engine was stripped, inspected and repaired by Alba and deemed fit for service.

4.1.3 Engine # 202223

- 2012 - The engine was removed from Hardwoods and shipped to Scotland where it was stripped, inspected and overhauled by Alba and deemed fit for service;
- 2013 – The engine was installed in B position at SVL;
- 2014 – The recently installed overhauled engine failed with approximately 30 hours of operation due to a failed No. 7 bearing. The engine was removed and shipped to Scotland where it was stripped, inspected and overhauled by Alba and deemed fit for service. Leased engine 202040 was installed in its place;
- 2019 – Damaged combustion chamber, bearings and HP blades. The engine was removed, and shipped to Scotland where it was stripped, inspected and overhauled by Alba and deemed fit for service. The engine was installed at HWD in position B when returned from Alba.

4.1.4 Engine # 202224

- 2013 – Leased engine 202225 was removed and 202224 installed;
- 2015 – Combustion chamber severely damaged. The engine was removed shipped to Scotland where it was stripped, inspected and overhauled by Alba and deemed fit for service. Leased engine 202040 was installed in its place;
- 2017 – Erosion and cracking of combustion chambers including LP turbine blade damage. The engine was removed, stripped, inspected and overhauled by Alba and deemed fit for service.

Each startup subjects the combustion turbine to significant thermal and mechanical stresses, accelerating wear on components like bearings, seals, and turbine blades. This is particularly relevant in peaking power applications, where combustion turbines are frequently cycled on and off, as opposed to base-load operations with continuous running. By incorporating start counts into maintenance intervals alongside operating hours, operators can more accurately predict component fatigue, reduce the risk of unexpected failures, and optimize lifecycle costs.

The ramp rate of increasing the power output of the combustion turbine engine can also have an impact of accelerating thermal stress and wear when the power increase over time is greater than the rating of the combustion turbine engine. NL Hydro indicated that during the above period evaluated, prior to 2019 the control system droop settings allowed power increase ramp rates that exceeded the recommended operation of the RR Olympus combustion turbine engines which may have increased the repair and overhaul frequency. This control issue is advised to have been resolved in 2019.

4.2 Recommendation

The typical overhaul frequency on the current fleet of RR Olympus engines is advised by Sulzer to be between 300 to 500 starts. This engine overhaul frequency is based on Sulzer experience with the combustion turbine fleet they are currently supporting. Sulzer estimates approximately 70 to 80 RR Olympus engines are still operating. The NL Hydro fleet is at the lower end of this interval indicating a decline in reliability consistent with advanced age and wear.

Based on the maintenance history and operating profiles for the HWD and SVL power plants, and Sulzer input on the number of starts between overhauls, the power plant sustaining capital forecasts should consider a number of start-based combustion turbine overhaul interval requiring a potential overhaul every 330 starts. The forecast power plant operation and overhaul timing which should be considered for each power plant is summarized below.

4.2.1 Hardwoods

The HWD power plant is expected to be subject to the following operating profile from 2025 to 2040:

- 80 starts per year/engine;
- 230 generating operating hours per year;
- 5,900 synchronous condensing operating hours per year.

Based on the above operating profile of 80 starts per year per combustion turbine engine an overhaul every 4 years (after 300 to 350 starts) starting from the last year of overhaul should be considered for each combustion turbine engine.

4.2.2 Stephenville

The SVL power plant is expected to be subject to the following operating profile from 2025 to 2040:

- 40 starts per year/engine;
- 125 generating operating hours per year;
- 3,800 synchronous condensing operating hours per year.

Based on the above operating profile of 40 starts per year per combustion turbine engine an overhauls every 8 years (after 300 to 350 starts) starting from the last year of overhaul should be considered for each combustion turbine engine.

5. Control System Review

5.1 Hardwoods

5.1.1 *ESLAG Bailey INFI 90 DCS*

The combustion turbine control system at HWD is based on the ELSAG Bailey INFI 90 Distributed Control System (DCS), installed in 1997. The system is currently supported by ABB, which offers an upgrade path to System 800xA. This platform allows integration between the existing INFI 90 control environment and newer functionalities such as tag handling, operator interface updates, and system monitoring tools.

System 800xA also enables connectivity to additional features including asset management, data handling, and updated operator workstations. Users may choose to retain the current system configuration or implement selected enhancements. ABB has maintained backward compatibility across successive generations of the INFI 90 product line and provides a Life Cycle and Migration program to support long-term planning. A Distributed Control System Life Cycle and Migration Report was prepared for NL Hydro in October 2021 which provided a list of key components and their parts and service support status which is included in Appendix D.1.

The following summary from the referenced ABB report outlines the findings and recommendations of the ABB lifecycle plan provided in October 2021:

Although most of the I/O modules at Hardwoods are obsolete, ABB has created a new generation of surface mount technology modules that offer a 1:1 replacement. Sufficient plant spares should be on hand in the event of failure. The non-volatile memory chip of the IMMFP02 controllers has a battery with a shelf life of 10 years. This should be replaced so the controllers will not lose their programs in the event of a power failure.

The ABB report includes the following recommendations:

Based on the current systems of NL Hydro, ABB is recommending the following upgrade for migration management and will provide upgrade proposals for the Hardwoods Power Plant.

1. *Hardwoods MFP02 non-volatile memory replacement/BRC410 upgrades. These modules are obsolete and these chips may no longer be available. Therefore, we recommend upgrading these to BRC410 controllers.*

NL Hydro advises that the above recommendations from the ABB lifecycle plan have not yet been implemented at the HWD power plant.

5.1.2 *Control System HMI*

Human machine interfaces (HMI) require continuous upgrades and updates. Updates and security patches are applied to reduce system vulnerabilities to cyber and physical attacks. Embedded systems such as these are typically changed every 10 years and upgraded to the latest operating system including security, antivirus, and firewall. An HMI upgrade is required to meet the projected end of service life where engineering workstations, hardware and software require constant updates.

The HWD Engineering Workstations including software were last replaced in 2018/2019. This system is out of date and running software which is currently not supported and requires immediate replacement to ensure reliable operation.

5.1.3 *Instrumentation*

The balance-of-plant instrumentation has undergone selective upgrades and replacements over the life of each plant; however, some original instruments remain in service and are over 50 years old. This instrumentation and any others older than 20 years should be scheduled for replacement due to obsolescence risks, limited spare parts availability, and lack of direct replacements.

A detailed survey of instrumentation at HWD is recommended to be completed to identify aging devices and develop replacement strategies. Some instruments may require alternative technologies, necessitating engineering review to determine the most suitable options. Instruments that are original to the plants should be prioritized for immediate replacement.

A multi-year replacement program should be established for both sites to mitigate the risk of unexpected failures, which could lead to extended outages. Older instruments may not integrate effectively with modern control systems, impacting combustion turbine operation. Proactive planning will reduce downtime and ensure system reliability.

5.1.4 *Recommendations*

Based on the review of the combustion turbine control system, instrumentation and balance of plant control system the following is recommended:

- **Continue Collaboration with ABB:**
  - Proceed with ABB's Life Cycle and Migration Program for upgrading INFI 90 to System 800xA;
  - Follow up annually with ABB for future updated lifecycle reports and recommendations.
- **Replace HMI and Engineering Workstations at HWD:**
  - Immediate action required to maintain operational reliability and cybersecurity.

- **Instrumentation Replacement Program:**
  - Initiate a multi-year project to replace all instrumentation older than 20 years at both sites;
  - Prioritize original instruments for immediate replacement.

5.2 Stephenville

5.2.1 ESLAG Bailey INFI 90 DCS

The combustion turbine control system at SVL is based on the ELSAG Bailey INFI 90 Distributed Control System (DCS), installed in 1999. The system is currently supported by ABB, which offers an upgrade path to System 800xA. This platform allows integration between the existing INFI 90 control environment and newer functionalities such as tag handling, operator interface updates, and system monitoring tools.

System 800xA also enables connectivity to additional features including asset management, data handling, and updated operator workstations. Users may choose to retain the current system configuration or implement selected enhancements. ABB has maintained backward compatibility across successive generations of the INFI 90 product line and provides a Life Cycle and Migration program to support long-term planning. A Distributed Control System Life Cycle and Migration Report was prepared for NL Hydro in October 2021 which provided a list of key components and their parts and service support status which is included in Appendix D.2.

The following summary from the referenced ABB report outlines the findings and recommendations of the ABB lifecycle plan provided in October 2021:

Although most of the I/O modules at Stephenville are obsolete, ABB has created a new generation of surface mount technology modules that offer a 1:1 replacement as the present modules age. Sufficient plant spares should be on hand in the event of failure. The first upgrade here should be the original DC power system because of the significant deterioration of these electronic components. Due to the AC/DC voltage conversion and high amperage levels, the power supplies experience considerable heating and cooling. Next the non-volatile memory chip of the IMMFP02 controllers should be replaced. These have a battery with a shelf life of 10 years and are used to store the controllers' program during a power failure. The old PCV operator console is obsolete and needs to be upgraded to a new computer & software. This will also require new CIU modules to be compatible with the new software as was done at Hardwoods in 2019.

The ABB report includes the following recommendations:

Based on the current systems of NL Hydro, ABB is recommending the following order of priority for migration management and will provide upgrade proposals for these plants.

1. *Stephenville modular power system upgrade to the latest hardware MPS_IV.*
2. *Stephenville operator console upgrade to S+ Operations.*
3. *Stephenville IMMFP02 non-volatile memory replacement/BRC410 upgrades.*
4. *These modules are obsolete and these chips may no longer be available. Therefore, we recommend upgrading these to BRC410 controllers.*

NL Hydro advises that recommendations 1 and 2 above from the ABB lifecycle plan have not yet been implemented at the SVL power plant, while the recommendations 3 and 4 with regard to the BRC410 memory and controller components have been implemented.

5.2.2 Control System HMI

Human machine interfaces (HMI) require continuous upgrades and updates. Updates and security patches are applied to reduce system vulnerabilities to cyber and physical attacks. Embedded systems such as these are typically changed every 10 years and upgraded to the latest operating system including security, antivirus, and firewall. An HMI upgrade is required to meet the projected end of service life where engineering workstations, hardware and software require constant updates.

The SVL Engineering Workstations were replaced in 2023/2024. The system software is out of date and is running software which is currently not supported and requires immediate replacement to ensure reliable operation. SVL is scheduled to be upgraded in 2026.

5.2.3 Instrumentation

The balance-of-plant instrumentation has undergone selective upgrades and replacements over the life of each plant; however, some original instruments remain in service and are over 50 years old. This instrumentation and any others older than 20 years should be scheduled for replacement due to obsolescence risks, limited spare parts availability, and lack of direct replacements.

A detailed survey of instrumentation at SVL is recommended to be completed to identify aging devices and develop replacement strategies. Some instruments may require alternative technologies, necessitating engineering review to determine the most suitable options. Instruments that are original to the plants should be prioritized for immediate replacement.

A multi-year replacement program should be established to mitigate the risk of unexpected failures, which could lead to extended outages. Older instruments may not integrate effectively with modern control systems, impacting combustion turbine operation. Proactive planning will reduce downtime and ensure system reliability.

5.2.4 Recommendations

Based on the review of the combustion turbine control system, instrumentation and balance of plant control system the following is recommended:

- **Continue Collaboration with ABB:**
  - Proceed with ABB's Life Cycle and Migration Program for upgrading INFI 90 to System 800xA;
  - Follow up annually with ABB for future updated lifecycle reports and recommendations.
- **Instrumentation Replacement Program:**
  - Initiate a multi-year project to replace all instrumentation older than 20 years at both sites;
  - Prioritize original instruments for immediate replacement.

6. Electrical System Review

6.1 Hardwoods Electrical System

6.1.1 Motor Control Center

The HWD Motor Control Centre (MCC) which provides AC and DC power distribution to auxiliary systems was installed in 1975, and is a Unitrol Type 9800 originally manufactured by Cutler-Hammer between 1956 and 1974. The MCC is now considered obsolete, and original parts are no longer produced. However, since Cutler-Hammer became part of Eaton in 1978, Eaton continues to support these products by providing compatible replacement components. These components are custom-built using Eaton parts and designed to fit the existing MCC framework, ensuring compatibility with the original design.

Eaton has reviewed the existing MCC and provided quotes for replacement parts.
A replacement MCC has been priced, but it introduces significant physical constraints. The new MCC design requires rear access, which is incompatible with the current building layout. A new structure would need to be built adjacent to the existing Control Room to accommodate the MCC. This would likely require replacement of all existing cabling, adding substantial cost and complexity. Replacement of the MCC is largely dependent on the future of the HWD power plant as a Generating plant or a Synchronous Condensing plant. Quotations received from Eaton are available in Appendix C.

6.1.1.1 Recommendations

Although replacement components are available, reliance on custom-built parts presents risks related to lead times, cost, and long-term support. The MCC is over 50 years old, and its age increases the likelihood of failure, which could result in extended outages and operational impacts. To mitigate these risks, it is recommended to:

- **Develop a Replacement Strategy:** Initiate planning for a complete MCC replacement with a modern, standardized system that meets current safety and reliability standards;
- **Conduct a Detailed Assessment:** Evaluate the existing MCC configuration, connected loads, and space constraints to determine the most suitable replacement solution. This would be dependent on the future operation of the plant;
- **Implement a Multi-Year Upgrade Plan:** Schedule the MCC replacement as part of a phased modernization program to minimize operational disruptions;
- **Consider Spare Parts Risk:** Continue to maintain an inventory of critical spare components and establish agreements with Eaton for expedited manufacturing of custom parts.

Proactive replacement will reduce the risk of unplanned outages, improve system reliability, and align with industry best practices for aging electrical infrastructure.

6.1.2 HV Breakers

The 13.8 kV breakers were replaced at HWD in 2000. Based on their current condition and operational performance, no immediate replacement or upgrade is recommended at this time.

6.1.2.1 Recommendations

Although the breakers are performing satisfactorily, they are now over 20 years old and approaching the later stages of their expected service life. To ensure continued reliability and minimize the risk of unexpected failures, it is recommended to:

- **Continue Condition Monitoring:** Maintain regular inspections, testing, and trending of breaker performance parameters;
- **Plan for Future Replacement:** Include these breakers in long-term asset management plans to allow for timely procurement and engineering review when replacement becomes necessary depending on the future of the power plant;
- **Maintain Spare Parts Strategy:** Ensure availability of critical spare components or identify compatible replacement parts.

6.1.3 Transformers

The generator step-up transformers were excluded from the scope of this study. The auxiliary power transformers, original to the generating station, have not been replaced during their operational life. Both transformers are expected to remain in service for the remaining life of the station and are therefore considered outside the sustaining capital plans outlined in this report.

Maintenance and lifecycle planning for these assets are managed by other asset planning groups within NL Hydro and are not included in this Condition Assessment.

6.1.3.1 Recommendations

Although these transformers are outside the scope of this assessment, their age and criticality warrant continued monitoring and proactive risk management. It is recommended to:

- **Maintain Regular Condition Monitoring:** Continue oil analysis, thermographic inspections, and electrical testing to detect early signs of deterioration;
- **Coordinate with Asset Planning Groups:** Ensure alignment between this assessment and NL Hydro’s broader asset management strategy to avoid gaps in lifecycle planning.

While immediate replacement is not anticipated, proactive planning will mitigate operational and reliability risks associated with aging transformer assets.

6.2 Stephenville Electrical System

6.2.1 Motor Control Centre

The SVL Motor Control Centre (MCC) which provides AC and DC power distribution to auxiliary systems was replaced in 2015 and therefore replacement is not considered necessary for the remaining operating life of the power plant.

6.2.2 HV Breakers

The 13.8 kV breakers were replaced at SVL in 1999. Based on their current condition and operational performance, no immediate replacement or upgrade is recommended at this time.

6.2.2.1 Recommendations

Although the breakers are performing satisfactorily, they are now over 20 years old and approaching the later stages of their expected service life. To ensure continued reliability and minimize the risk of unexpected failures, it is recommended to:

- **Continue Condition Monitoring:** Maintain regular inspections, testing, and trending of breaker performance parameters;
- **Plan for Future Replacement:** Include these breakers in long-term asset management plans to allow for timely procurement and engineering review when replacement becomes necessary depending on the future of the power plant;
- **Maintain Spare Parts Strategy:** Ensure availability of critical spare components or identify compatible replacement parts.

6.2.3 Transformers

The generator step-up transformers were excluded from the scope of this study. The auxiliary power transformers, original to the generating station, have not been replaced during their operational life. Both transformers are expected to remain in service for the remaining life of the station and are therefore considered outside the sustaining capital plans outlined in this report.

Maintenance and lifecycle planning for these assets are managed by other asset planning groups within NL Hydro and are not included in this Condition Assessment.

6.2.3.1 Recommendations

Although these transformers are outside the scope of this assessment, their age and criticality warrant continued monitoring and proactive risk management. It is recommended to:

- **Maintain Regular Condition Monitoring:** Continue oil analysis, thermographic inspections, and electrical testing to detect early signs of deterioration;
- **Coordinate with Asset Planning Groups:** Ensure alignment between this assessment and NL Hydro's broader asset management strategy to avoid gaps in lifecycle planning.

While immediate replacement is not anticipated, proactive planning will mitigate operational and reliability risks associated with aging transformer assets.

7. Major Upgrades

7.1 Hardwoods Major Upgrades

The table below outlines major upgrades and the associated costs from 2010-2024 completed at HWD. Over this time period a total of $22,318,800 was invested in major upgrades at HWD.

Table 7-1: HWD Historical Major Upgrades ($1000's)

Year(s)	Cost ($)	Project
2010-2012	$4,506	Life extension project: • Refurbish inlet air system and exhaust stacks; • Engine overhauls/PT inspection; • Inlet air/exhaust stack refurbishment; • Main lube oil cooler refurbishment; • Enclosure refurbishment; • Fuel tank refurbishment; • Other misc. refurbishments.
2013	$8,420	Generator replacement.
2016	$255	Fuel piping replacement within engine enclosures.
2016	$3,047	Engine 202205 refurbishment.
2016	$80.7	Replace 125V batteries.
2017	$957	Life Extension Project: • Filtration upgrades; • Instrumentation upgrades; • Fuel heater replacement.
2018	$3,823	Life Extension Project: • Replace demister; • Upgrade air inlet and exhaust stacks.
2019	$685.9	Upgrade HMI & AVR.
2019	$404.2	Replace fuel control valves.
2024	$50	Control module and 13.8KV breaker building external building repairs.
2024	$90	Generator partial discharge monitoring system replacement.

7.2 Stephenville Major Upgrades

The table below outlines major upgrades and the associated costs from 2010-2024 completed at SVL. Over this time period a total of $23,391,000 was invested in major upgrades at SVL.

Table 7-2: SVL Historical Major Upgrades ($1000's)

Year(s)	Cost ($)	Project
2010-2014	$1,147	Glycol system upgrades.
2012-2013	$5,700	Generator Rewind and Major Overhaul:
2014-2015	$1,353	• Replace fuel filtration system; • Upgrade instrumentation; • Replace fuel valve actuators; • Upgrade air start system.
2015	$2,665	• Replace motor control center; • Replace station service transformer power cable; • Replace vibration sensors.
2016	$2,525	• Exhaust stack and air inlet repair; • Generator fire suppression installation; • Install of new main lube oil glycol heat exchanger, main lube oil pumps, and glycol pump.
2017	$634	• Instrumentation upgrades; • Replace obsolete instrumentation; • Install additional instrumentation including wiring to DCS and I/O cards; • Install of emergency stops in engine enclosures.
2017	$230	Filtration upgrades: • Fuel offloading, forwarding duplex filter; • Duplex oil filter, fuel heater.
2017	$489	Replace generator bed heater.
2018	$243	Replace demister system.
2020	$405	Upgrade HMI.
2024	$8,000	Generator rotor fan failure – generator repairs.

8. Condition Assessment

8.1 Boundaries

The Condition Assessment provided with this report includes all major system components of the HWD and SVL Generating Stations which are summarized below:

- Fuel unloading system;
- Fuel distribution system;
- Fuel forwarding module;
- Control module;
- Air intake structures;
- Combustion turbines;
- Power turbines;
- Generators;
- Exhaust stacks;
- Building enclosures;
- Clutches, generator, and exciter;
- Control systems;
- Power systems;
- Auxiliary systems including compressed air, lube oil, glycol systems, etc.;
- Turbine performance and reliability upgrades.

The following areas were excluded from the condition assessment based on the study scope requested by NL Hydro:

- Fuel storage;
- Terminal station;
- Maintenance buildings.

8.2 Asset Grading

Grades on a scale of 1 to 5 based on their observed visual condition have been assigned based on the following table to each critical asset.

Table 8-1: Asset Grading Scale

Grade	Condition	Description
5	Excellent	No visible defects, new or near new condition, may still be under warranty if applicable.
4	Good	Good condition, but no longer new, may have some slightly defective or deteriorated component(s), but is overall functional.
3	Adequate	Moderately deteriorated or defective components; but has not exceeded useful life.
2	Marginal	Defective or deteriorated component(s) in need of replacement; exceeded useful life.
1	Poor	Critically damaged component(s) or in need of immediate repair; well past useful life.
INA	--	Information Not Available. Information was not available or was inconclusive.

8.3 Hardwoods

Based on site visits to the power plant site, discussions with the operations team, documentation review and consideration of the age of the equipment and assets a summary of the grades assigned to major equipment is provided in the Tables below. The condition ratings also consider recent sustaining capital investment where applicable.

Table 8-2: HWD Power Block Grading

Description	Grade	Comments
Combustion Turbine Engine 202205, and 202223	**2**	OEM support has been discontinued; new parts support is not available.
Curtiss Wright Power Turbine	**3**	OEM support has been discontinued; new parts support is not available.
SSS Power Turbine Clutches	**3**	Original equipment, OEM support is still available.
Generator	**4**	Generator was replaced in 2013. No issues identified.
Air Inlet System	**3**	Coating deterioration and corrosion identified, refurbishment required (advised to have been completed post site visit, which would raise grading to 4).
Exhaust Stacks	**3**	Coating deterioration and corrosion identified, refurbishment required.
Generator and Power Turbine Enclosure	**3**	Coating deterioration and corrosion identified, refurbishment required (advised to have been completed post site visit, which would raise grading to 4).
Main Lube Oil System (common to the Power Turbines, Clutches and Generator Bearings)	**3**	System experiences summer derating. Upgrades planned to improve oil circulation flow to generator.
Fire Fighting System	**3**	Recommended works identified to replace cylinder flex hoses and pull stations.

Table 8-3: HWD I&C Asset Grading

Description	Grade	Comments
Bailey Control System	**3**	ABB Lifecycle report recommends upgrades and enhancements (see section 5.1.1).
Balance of Plant Instrumentation	**3**	Remaining original instrumentation, and instruments over 20 years in age recommended for replacement (see section 5.1.3).
Combustion Turbine Control Building Envelope	**3**	Recently refurbished, however new siding was added over deteriorated building envelope.

Table 8-4: HWD Electrical Asset Grading

Description	Grade	Comments
High Voltage Switchgear Building Envelope	**3**	Recently refurbished, however new siding was added over deteriorated building envelope.
13.8 kV Switchgear (generator breaker)	**4**	Replaced in 2000. No issues identified.
Generator Output Bus Duct	**3**	Original. Requires continued monitoring for coating and corrosion deterioration.
Generator protection relays	**4**	Replaced during life of plant. No issues identified.
Sync-check relay	**3**	Original. No issues identified.
Motor Control Centres (AC & DC)	**3**	Original. Original parts no longer available, however part substitution options have been identified.
Station DC supply (batteries and chargers)	**3**	Batteries are due for replacement in 2026.
Inverter (AC supply for control systems)	**5**	Inverter was replaced in 2019.
Blackstart Emergency Diesel Generator	**3**	Installed as a used unit in 2005. Scheduled for replacement in 2027.

Table 8-5: HWD Fuel Oil Asset Grading

Description	Grade	Comments
Fuel Unloading Systems	**4**	Original, no issues identified.
Fuel Piping	**3**	Replaced in 2005. Coating deterioration identified, recoating planned (advised to have been completed post site visit, which would raise grading to 4)
Fuel Forwarding System	**4**	Upgraded in 2007. No issues Identified.
Fire Fighting Systems	**3**	Recommended works identified to replace cylinder flex hoses and pull stations.

Table 8-6: HWD Glycol Cooling Asset Grading

Description	Grade	Comments
Main Lube Oil Cooling System/Glycol Cooler	2	Air cooled heat exchanger is original, system experiences summer derating.

Table 8-7: HWD Support Buildings Asset Grading

Description	Grade	Comments
Auxiliary Module Building	4	Most recent work completed during compressor room construction in 1990s. Minor issues observed with corrosion to door frames, and pipe support base plates.
Control Building	3	Refurbished in 2024. New siding was identified to have been installed over deteriorated building envelope.
Maintenance and Parts Storage Building Envelope	4	Recently renovated in 2024. No issues identified.

8.4 Stephenville

Based on a site visit to the power plant site, discussions with the operations team, documentation review and consideration of the age of the equipment and assets a summary of the grades assigned to major equipment is provided in the Tables below. The condition ratings also consider recent sustaining capital investment where applicable.

Table 8-8: SVL Power Block Grading

Description	Grade	Comments
Combustion Turbine Engine #202224 #202204	2	OEM support has been discontinued; new parts support is not available.
Curtiss Wright Power Turbine	3	OEM support has been discontinued; new parts support is not available.
SSS Power Turbine Clutches	3	Original equipment, OEM support is still available.
Generator	3	Generator was replaced in 2012. Rotor fan failure was experienced in 2024.
Air Inlet System	3	Coating deterioration and corrosion identified, refurbishment required.
Exhaust Stacks	3	Coating deterioration and corrosion identified, refurbishment required.
Generator and Power Turbine Enclosure	3	Coating deterioration and corrosion identified, refurbishment required.
Main Lube Oil System (common to the Power Turbines, Clutches and Generator Bearings)	3	Air cooled heat exchanger was replaced in 2014. Corrosion and deterioration observed on frame and tube supports based on photos provided by NL Hydro.
Generator Air Cooling System	4	Generator heat exchanger was replaced in 2012.
Fire Fighting System	3	Recommended works identified to replace cylinder flex hoses and pull stations.

Table 8-9: SVL I&C Asset Grading

Description	Grade	Comments
Bailey Control System	**3**	ABB Lifecycle report recommends upgrades and enhancements (see section 5.2.1).
Balance of Plant Instrumentation	**3**	Remaining original instrumentation, and instruments over 20 years in age recommended for replacement (see section 5.2.3).
Combustion Turbine Control Building Envelope	**4**	No issues identified.

Table 8-10: SVL Electrical Asset Grading

Description	Grade	Comments
High Voltage Switchgear Building envelope	**3**	Replaced in 1999. Building envelope deterioration identified.
13.8 kV Switchgear (generator breaker)	**4**	Replaced in 1999. No issues identified.
Generator Output Bus Duct	**4**	Replaced in 1999. No issues identified.
Generator protection relays	**4**	Replaced during life of plant. No issues identified.
Sync-check relay	**3**	Original. No issues identified.
Motor Control Centres (AC & DC)	**4**	Replaced in 2015. No issues identified
Station DC supply (batteries and chargers)	**3**	Batteries are due for replacement in 2025.
Inverter (AC supply for control systems)	**5**	Inverter was replaced in 2016.
Emergency Backup Diesel Generator	**3**	Installed as a used unit in 2006. Scheduled for replacement in 2027.

Table 8-11: SVL Fuel Oil Asset Grading

Description	Grade	Comments
Fuel Unloading Systems	**4**	Original, no issues identified.
Fuel Piping	**4**	Replaced in 2008.
Fuel forwarding system	**4**	Upgraded in 2015. No issues Identified.
Fire Fighting Systems	**3**	Recommended works identified to replace cylinder flex hoses and pull stations.

Table 8-12: SVL Glycol Cooling Asset Grading

Description	Grade	Comments
Main Lube Oil Cooling System/Glycol Cooler	**4**	Upgraded in 2014. No issues identified.

Table 8-13: SVL Support Buildings Asset Grading

Description	Grade	Comments
Control and Auxiliary Building Envelope	**4**	No issues identified.
Maintenance and Parts Storage Building Envelope	**4**	No issues identified.

9. Sustaining Capital and Operating Plan Forecast and Retirement Optimization

Sustaining capital plans for the HWD and SVL power plants were developed on the following basis:

Hardwoods

- 80 starts per year/engine;
- 230 generating operating hours per year;
- 5,900 synchronous condensing operating hours per year.

Stephenville

- 40 starts per year/engine;
- 125 generating operating hours per year;
- 3,800 synchronous condensing operating hours per year.

The sustaining capital plans for both the HWD and SVL power plants include the following:

- Costs for Capital Upgrades and Maintenance;
- Costs for Plant upgrades and/or modifications;
- Combustion turbine engine start quantity and years of operation triggers for routine maintenance considering both OEM intervals and intervals needed based on operating experience with the station;
- Repetition of unplanned maintenance which has occurred on an age basis;
- Frequency of repairs and refurbishments that have been required for specific assets during the operating life of the station. The long operating history of the station has established a baseline for investment frequency needed due to age based deterioration.

Sustaining capital costs used as inputs to the plan are based on historical station project costs, internal references and allowances based on estimating experience which have been scaled up to and presented on a 2025 cost basis escalated at 3% annually for future years of operation.

9.1 Hardwoods (HWD) Sustaining Capital Plan

Upgrades to the power plant to sustain or improve reliability will be required for continued operation of the power plant. Hatch considers there are also mandatory maintenance items that include the service of the combustion turbines and power turbine. Sustaining capital profiles have been prepared for potential operation of the power plant until 2035 or 2040 based on the recommended and forecasted works required to sustain operation. These potential years of retirement are considered on the following basis:

- Considering the current NL Hydro capital project workload and the typical project development timeline from the scoping study stage, 2035 is the earliest practical year in which a replacement project could be completed;
- Sulzer recommends that operators of the RR Olympus combustion turbine generator consider 2040 as the latest retirement year in planning for continued support. During a meeting held to review the current outlook and support capability for the RR Olympus combustion turbine model Sulzer indicated that while their plans are to continue to support the model, other customers operating the current fleet have plans to retire their units over the next 10 years. Sulzer is the sole service provider supporting the RR Olympus combustion turbine generators for NL Hydro and further reductions in the number of units remaining in the operating fleet may continue to increase challenges in securing effective parts and service support.

Sustaining capital forecast plans for operation of the HWD power plant through 2035 versus 2040 are provided in Table 9-1. Details of the recommended Capital Upgrades, and Major Maintenance items are discussed in this section and a further breakdown of the estimated costs is provided in Appendix A.1 and A.2.

Table 9-1: HWD Summary of Costs by Scenario ($1000's)

Case		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Total
HWD 2035	Capital	304	4,587	6,046	4,260	938	3,172	-	3,366	127	-	-	-	-	-	-	-	$22,799
	Operating	520	536	552	568	585	603	621	640	659	678	699	-	-	-	-	-	$6,660
	Total	**824**	**5,122**	**6,597**	**4,828**	**1,523**	**3,775**	**621**	**4,005**	**785**	**678**	**699**	-	-	-	-	-	**$29,459**
HWD 2040	Capital	304	4,587	6,046	4,260	938	3,578	-	3,981	127	3,605	341	3,997	635	4,501	-	-	$36,899
	Operating	520	536	552	568	585	603	621	640	659	678	699	720	741	764	787	810	$10,482
	Total	**824**	**5,122**	**6,597**	**4,828**	**1,523**	**4,181**	**621**	**4,620**	**785**	**4,283**	**1,040**	**4,717**	**1,377**	**5,265**	**787**	**810**	**$47,380**

Note: Capital and Operating costs are escalated by 3% annually in the above forecast.

The sustaining capital forecast for the HWD generating station considers the following refurbishment cycles based on typical asset refurbishment and replacement cycles from Hatch experience in sustaining capital planning for thermal power plants, the historical investment cycle and maintenance requirements of the generating station, issues identified during the condition assessment, and current capital projects in progress or planned by NL Hydro. In some cases, capital projects are deferred to start in 2027 to enable sufficient time for planning, procurement and implementation:

Combustion Turbine Engines: The typical overhaul frequency on the current fleet of RR Olympus engines is between 300-500 starts. The NL Hydro fleet is at the lower end of this interval indicating a decline in reliability consistent with advanced age and wear. The sustaining capital profile for HWD assumes 80 starts per year per combustion turbine engine and overhauls every 4 years (after 300 to 350 starts) for each combustion turbine engine. NL Hydro maintains one rotational spare combustion turbine engine. When an overhaul or repair is required the engine is removed and exchanged with the rotational spare and sent offsite for repair or overhaul. The removed engine then becomes the rotational spare available for installation when needed at either of the HWD or SVL power plant sites. An upgrade to add removable insulating blankets to the combustion turbine engine hot section and exhaust to reduce heat rejection to the enclosure and reduce summer derating is also recommended and included in 2026. NL Hydro has also advised that spare parts support for the engine ignition systems are no longer available, therefore an ignition system upgrade is included in 2026 in the profile.

Air Intake System: The combustion turbine engine air intake experiences coating deterioration and corrosion due to the environmental conditions on site and requires periodic inspection, metal repairs, and coating refurbishment. Based on the historical investment required, a 10-year interval is included in the profile. During the 2025 site visit these coating repairs were seen to have been started and have since been completed. The combustion turbine engine air intake filters also require periodic replacement, and a 5-year air filter replacement cycle is included in the profiles starting in 2028. This is based on NL Hydro operating experience and the most recent replacement year being advised to have been in 2023. The intake interior sections were not opened for viewing during the site visits, although are advised by NL Hydro to be in good condition.

Exhaust Stacks: The combustion turbine exhaust stacks experience coating deterioration and corrosion due to the environmental conditions on site and require periodic inspection, metal repairs, and coating refurbishment. Based on the historical investment required, a 10-year interval is included in the profile. This will start in 2028 as the most recent repairs were indicated to have been completed in 2018. The exhaust system interior sections were not possible to view during the site visit. NL Hydro advises that the internal sections require a detailed inspection as they are covered by stainless steel plating.

Engine Lube Oil Systems: NL Hydro has previously identified a need to upgrade the lube oil filter system for the combustion turbine engines due to challenges in sourcing filter media for the original filter housings. The new filter housings have already been sourced and were viewed on site during the site visit. NL Hydro advises the new filter housing and filters were installed on Unit A in 2025 and are planned for installation on Unit B in 2026. This cost is split between 2025 and 2026 in the profile and is not expected to be incurred again in the remaining life of the power plant in the operating profiles considered.

Compressed Air Systems: The balance of plant compressed air system will require upgrades and refurbishment over time with equipment upgrades expected to be necessary on a 30-year investment cycle. Upgrades consist of replacement of the air compressors and air dryer due to obsolescence and declining parts and service support, and refurbishment of the air receivers based on pressure vessel inspection findings. NL Hydro advises that new air compressors were installed in 2007 and there are plans for an instrument air dryer replacement in 2026. It was also advised that pressure vessel inspection report findings in 2025 required refurbishment of the air receivers. Therefore, costs are carried in 2025 and 2026 for the air receiver refurbishment and air dryer upgrades.

Power Turbines: Based on the expected operation of the power plant A and B side power turbine inspections by Sulzer are recommended on a 10-year basis. It was advised that the most recent inspection was in 2015. This inspection cycle is scheduled to start in 2027 in the profile to allow time to secure quotations and budget approval.

SSS Clutches: The SSS clutch service manual indicates that service is required after 1,000 to 1,200 starts. Based on the expected operation of the power plant and number of starts per year this service interval is included in the plan on a 10-year cycle starting in 2027 to align with the power turbine inspections. It was advised by NL Hydro that the last service performed was in 2016.

Main Lube Oil Cooling System: The air-cooled heat exchanger which provides cooling to the generator lube oil system is original and has not been replaced during the lifetime of the power plant. Based on typical 20-to-30-year lifetimes for fin fan heat exchangers in the applicable environmental conditions, Hatch recommends a 30-year replacement cycle for this equipment which is critical to plant operation. A typical failure point on this equipment is where the finned tubes connect to the radiator headers. In some cases, failed tubes can be cut and capped, to allow for continued use of the heat exchanger however as finned tubes are removed from operation, the heat exchange surface and capacity of the heat exchanger is reduced. The profile includes a replacement of this heat exchanger in 2027. The station also experiences derating during the summer months due to challenges with the generator lube oil cooling system. Recent studies indicate that this may be due to excessive lube oil flow bypassing the bearings and recirculating to the lube oil tank. Upgrades to improve the system ability to regulate the recirculating flow while remaining within the allowable supply pressure range were recommended to mitigate this issue. While the study report also suggested VFD drives be considered for this system, the use of VFDs is not recommended for this critical system. NL Hydro advises these upgrades have since been completed.

Generator: The generator is advised by NL Hydro to have been replaced in 2013. Hatch considers that a 40-year life of the generator can be expected with only cleaning and rewind activities in the event of a failure being required. No further replacement costs are forecast in the profile.

Automatic Voltage Regulator (AVR): The AVR system is advised by NL Hydro to have been upgraded in 2019 with an AVR system supplied by Basler. Hatch recommends that a 20-year upgrade cycle be considered for the AVR to ensure parts and service support remains available. However, no costs are included in the profile for replacement as this would be past or near to the retirement years of 2035 and 2040 considered in the profiles.

Motor Control Center (MCC): The motor control center (MCC) which provides AC and DC power distribution to auxiliary systems is original and original replacement parts are no longer available. Replacement parts are therefore often custom built which presents risks related to lead times, cost and long-term support. To ensure reliability and parts support for this critical equipment which supports the plant auxiliary systems a 2-year replacement project starting in 2026 is included in the profile to allow 1 year for design and procurement, and 1 year for implementation.

Instrumentation and Control Systems: The balance of plant instrumentation has been subject to select upgrades and replacement over the lifetime of each of the power plants. Any Instrumentation which is older than 20 years should be scheduled for replacement due to the risk of being obsolete with limited spare parts support. Older instruments could fail at any time and result in an extended plant shutdown as the original instruments are no longer available, and replacements will require engineering inputs to find a suitable replacement. A 3-year project is considered in the profile starting in 2027 to ensure the availability of spare parts, I/O cards and instrument support.

Bailey Control System: The combustion turbine control system is an ELSAG Bailey INFI 90 DCS which was installed in 1997 at HWD and includes components for which replacement parts are no longer available. The Bailey INFI 90 system is supported by ABB and can be upgraded to a DCS System 800xA. ABB offers a Life Cycle and Migration program which outlines a lifecycle plan. The profile considers a phased 3-year project to update the Bailey Control system starting in 2027 to ensure parts and service support and reliability.

13.8 kV Switch Gear (generator breaker): The 13.8 kV generator breaker was upgraded in the year 2000 and a 30-year upgrade cycle is recommended to ensure reliability and the availability of parts and service support. The profiles consider a breaker upgrade in 2030 for operation to 2040. For the 2035 profile this investment is deferred as replacement is near enough to the retirement year that an additional 5 years of operation beyond the recommended interval is considered reasonable.

Generator Protection Relays: The generator protection relays were upgraded in the year 2000 and a 20-year upgrade cycle is typically recommended to ensure reliability and the availability of parts and service support. However, based on the current condition of the protection relays the profiles consider deferring the protection relay upgrade for another 5 years and it is recommended that this upgrade be combined with the generator breaker upgrade in 2030, and this combined upgrade is considered in the 2040 profile. For the 2035 profile this investment is deferred as replacement is near enough to the retirement year that an additional 5 years of operation beyond the recommended interval is considered reasonable.

125V DC Batteries and Chargers: The 125V DC batteries ensure that uninterrupted control power is available in case of a power loss and to ensure a safe shutdown of the combustion turbine generators can be performed in a blackout condition. The operating life of the 125VDC batteries is typically 10 years before degradation of charge and amp hour storage becomes apparent. The inverter and battery chargers and battery monitoring system can also become a risk of failure and parts and service support, and a replacement/upgrade of this system is recommended on a 20-year interval. The 125 VDC batteries are advised by NL Hydro to be planned for replacement in 2026, and the inverter nameplate was observed to have a 2019 date stamp during the site visit. This planned replacement and the recommended replacement intervals are considered in the profiles.

Emergency Back Up Diesel Generator: The emergency generator was advised to have been last replaced in 2005 and to be planned for replacement in 2027. Based on the age of the unit replacement is recommended to ensure sufficient parts and service support. For emergency generators a typical 20-year replacement cycle is recommended, however if the genset model is still in production a control system upgrade could also be considered. The profile considers the planned replacement in 2027.

Auxiliary Transformer (13.8 kV/600 V): The auxiliary transformer which provides 600V low voltage power to the power plant is the original and has not been replaced during the life of the power plant. No replacement costs are considered in the profile. The transformer would be subject to condition monitoring and transformers of this type are typically able to operate past 50 years in age.

Transformer (66/13.8 kV): The generator step-up transformer which steps up the generator voltage to the terminal station voltage of 66 kV is the original and has not been replaced during the life of the power plant. No replacement costs are considered in the profile as this transformer is outside of the scope of the study.

Fuel Forwarding Equipment: The fuel forwarding equipment was advised to have been last upgraded in 2007. This equipment is comprised of pumps which draw fuel from the fuel storage pump and a high-pressure DC pump which delivers fuel to the combustion turbine engines. The system also includes a fuel viscosity heater which was advised to have been replaced in 2017. It was advised that the high-pressure DC pump is planned for replacement in 2027 which is considered in the profile. No further equipment replacements or upgrades are considered to be required in the profile.

Fuel Piping: The fuel pipeline between the main storage tank and the fuel forwarding building is advised to have been replaced in 2005. During the site visit it was evident that the coating has since deteriorated, which is essential to protecting the steel piping against corrosion. Recoating of the piping is advised to have been completed in 2025, and this cost is carried in the profile on a 10-year interval. During this interval UT thickness measurements can also be performed at spot locations to assess any signs of corrosion and piping wall thickness loss. This should focus on areas near to supports which have a higher failure potential due to the added support load. NL Hydro advises recoating of the fuel piping has been completed following the site visit.

Fire Protection and Detection Systems: Fire detection and protection systems typically experience reduced parts and service support over time as key components cease to be manufactured and are no longer available. Historical experience at the power plant has also identified pull station replacements and flex hose replacements to have been required within 20 years of operation of the fire detection systems and Ansul and Inergen fire protection systems installed. Based on this the profiles consider mid-life refurbishment costs in 2026 to address deficiencies, and a 30-year upgrade cost in 2032 based on 2002 being the last year the system was noted to have been upgraded.

GT Enclosures: During the site visits deterioration of the combustion turbine generator package enclosure coating and corrosion was observed. Environmental factors such as severe weather and the proximity of the Avalon peninsula to the Atlantic Ocean are known to accelerate coating deterioration and corrosion. Ensuring maintenance of the enclosure coating is essential to preventing corrosion of the combustion turbine generator enclosure package. Should the enclosure become compromised there is the risk that water ingress can cause damage to the combustion turbine engine, power turbine, generator and other auxiliary components. NL Hydro has recently completed recoating of the enclosure and this project is shown in the profiles for 2025. Based on the past frequency of this work being required, re-performance of this work is recommended and included on a 10-year cycle.

Maintenance Building: The maintenance building which also houses the operator facilities and power plant control room was renovated in 2024. It is recommended that budget is planned on a 10-year frequency for minor building repairs which is considered in the profile.

Blackstart Generator Building: The black start generator building was advised to have been constructed originally in 1995. During the site visit some deterioration of the building was observed with rotting wood seen in the building roofline. It is recommended that a roof replacement be considered during the planned genset replacement, and budget for this work is included in the profile. Maintaining the integrity of this building is essential to protecting the electrical equipment it houses.

Control Building: The most recent repairs on the control building are advised to have been performed in 2024 at which time new siding was added to the building. During the site visit it was observed that the new siding was added over top of the original deteriorated building siding. This may pose an issue as the original siding continues to deteriorate. Further refurbishment in 2027 is recommended during the recommended MCC replacement. Maintaining the building envelope is essential to protecting the critical controls and electrical equipment housed within the control building.

HV Breaker Building: It is recommended that a budget allowance is planned on a 10-year frequency for minor building repairs to maintain the integrity of the building envelope against age and environmental related deterioration which is considered in the profile. During the site visits, some deterioration was noted, including a corrosion related hole that had developed in the building floor plate; however, this has since been repaired.

Fuel Unloading and Fuel Forwarding Buildings: It is recommended that a budget allowance is planned on a 10-year frequency for minor building repairs which is considered in the profile to maintain the integrity of the building envelopes against age and environmental related deterioration.

9.1.1 *Summary of Hardwoods Sustaining Capital Plan Based on a 2035 Retirement Year*

The sustaining capital projects and investment included in the sustaining capital forecast from 2025 until retirement of the HWD power plant in 2035 are summarized as follows:

- 2025:
  - Combustion Turbine Engine Unit A Lube Oil System Upgrade;
  - Air Inlet System Refurbishment;
  - Air Receiver Refurbishment;
  - Fuel Distribution Piping Coating Refurbishment;
  - GT Enclosures Refurbishment.

- 2026:
  - Combustion Turbine Engine Unit B Lube Oil System Upgrade;
  - Insulating blanket installations on Combustion Turbine A and B hot sections;
  - Combustion Turbine Engine B Overhaul (Engine #202223 exchanged with #202420);
  - Compressed Air System Refurbishment;
  - Ignition System Upgrade;
  - MCC Replacement (year 1);
  - Station DC Battery Replacement;
  - Fire detection and protection system refurbishment;
  - Auxiliary Building Envelope Repairs.
- 2027:
  - Power Turbine A and B Inspections;
  - SSS Clutch Service;
  - Main Lube Oil Glycol System Cooler Replacement;
  - Bailey Control System Upgrade (year 1);
  - Instrumentation Upgrades and Control Upgrades (year 1);
  - MCC Replacement (year 2);
  - Emergency Generator Replacement;
  - Fuel Unloading Pump Upgrade;
  - Fuel Forwarding Equipment Upgrade;
  - Building Envelope Repairs for Black Start Building, Control Building, HV Breaker Building, Fuel Unloading Building and Fuel Forwarding Building.
- 2028:
  - Combustion Turbine Engine A Overhaul (Engine #202205 exchanged with #202204);
  - Air Intake Filter Replacement;
  - Exhaust Stack Refurbishment;
  - Bailey Control System Upgrade (year 2);
  - Instrumentation and Control Upgrades (year 2).

- 2029:
  - Bailey Control System Upgrade (year 3);
  - Instrumentation and Control Upgrades (year 3).
- 2030:
  - Combustion Turbine Engine B Overhaul (Engine #202420 exchanged with #202205).
- 2032:
  - Combustion Turbine Engine A Overhaul (Engine #202204 exchanged with #202420).
- 2033:
  - Air Intake Filter Replacement.

The following forecasted works and costs are deferred based on the 2035 retirement year:

- 13.8 kV Generator Breaker Upgrade (2030);
- Generator Protections Upgrade (2030);
- Fire detection and protection system upgrade (2032);
- Combustion Turbine Engine B Overhaul (2034);
- Air Intake refurbishment (2035);
- Fuel piping coating repairs (2035);
- GT enclosure refurbishment (2035).

9.1.2 *Summary of Hardwoods Sustaining Capital Plan Based on a 2040 Retirement Year*

The sustaining capital projects and investment included in the sustaining capital forecast from 2025 until retirement of the HWD power plant in 2040 are summarized as follows:

- 2025:
  - Combustion Turbine Engine Unit A Lube Oil System Upgrade;
  - Air Inlet System Refurbishment;
  - Air Receiver Refurbishment;
  - Fuel Distribution Piping Coating Refurbishment;
  - GT Enclosures Refurbishment.

- 2026:
    - Combustion Turbine Engine Unit B Lube Oil System Upgrade;
    - Insulating blanket installations on Combustion Turbine A and B hot sections;
    - Combustion Turbine Engine B Overhaul (Engine #202223 exchanged with #202420);
    - Compressed Air System Refurbishment;
    - Ignition System Upgrade;
    - MCC Replacement (year 1);
    - Station DC Battery Replacement;
    - Fire detection and protection system refurbishment;
    - Auxiliary Building Envelope Repairs.
- 2027:
    - Power Turbine A and B Inspections;
    - SSS Clutch Service;
    - Main Lube Oil Glycol System Cooler Replacement;
    - Bailey Control System Upgrade (year 1);
    - Instrumentation Upgrades and Control Upgrades (year 1);
    - MCC Replacement (year 2);
    - Emergency Generator Replacement;
    - Fuel Unloading Pump Upgrade;
    - Fuel Forwarding Equipment Upgrade;
    - Building Envelope Repairs for Black Start Building, Control Building, HV Breaker Building, Fuel Unloading Building and Fuel Forwarding Building.
- 2028:
    - Combustion Turbine Engine A Overhaul (Engine #202205 exchanged with #202204);
    - Air Intake Filter Replacement;
    - Exhaust Stack Refurbishment;
    - Bailey Control System Upgrade (year 2);
    - Instrumentation and Control Upgrades (year 2).

- 2029:
  - Bailey Control System Upgrade (year 3);
  - Instrumentation and Control Upgrades (year 3).
- 2030:
  - Combustion Turbine Engine B Overhaul (Engine #202420 exchanged with #202205);
  - 13.8 kV Generator Breaker Upgrade;
  - Generator Protections Upgrade.
- 2032:
  - Combustion Turbine Engine A Overhaul (Engine #202204 exchanged with #202420);
  - Fire detection and protection upgrade.
- 2033:
  - Air Intake Filter Replacement;
  - Maintenance and parts storage building envelope repairs.
- 2034:
  - Combustion Turbine Engine B Overhaul (Engine #202205 exchanged with #202204).
- 2035:
  - Air intake refurbishment;
  - Fuel piping coating refurbishment;
  - GT Enclosure refurbishment.
- 2036:
  - Combustion Turbine Engine A Overhaul (Engine #202420 exchanged with #202224);
  - Station DC Battery Replacement;
  - Auxiliary building envelope repairs.
- 2037:
  - Power Turbine A and B Inspections;
  - SSS Clutch Service;
  - Building Envelope Repairs for Black Start Building, Control Building, HV Breaker Building Fuel Unloading Building and Fuel Forwarding Building.

- 2038:
  - Combustion Turbine Engine B Overhaul (Engine #202204 exchanged with #202420);
  - Air Intake Filter Replacement;
  - Exhaust stack refurbishment.

The following forecasted works and costs are deferred based on the 2040 retirement year:

- Automatic Voltage Regulator Upgrade (2039);
- AC/DC Inverter Replacement (2039);
- Combustion Turbine Engine A Overhaul (2040).

9.2 Stephenville (SVL) Sustaining Capital Plan

Upgrades to the power plant to sustain or improve reliability will be required for continued operation of the power plant. Hatch considers there are also mandatory maintenance items that include the service of the combustion turbines and power turbine. Sustaining capital profiles have been prepared for potential operation of the power plant until 2035 or 2040 based on the recommended and forecasted works required to sustain operation. These potential years of retirement are considered on the following basis:

- Considering the current NL Hydro capital project workload and the typical project development timeline from the scoping study stage, 2035 is the earliest practical year in which a replacement project could be completed;
- Sulzer recommends that operators of the RR Olympus combustion turbine generator consider 2040 as the latest retirement year in planning for continued support. During a meeting held to review the current outlook and support capability for the RR Olympus combustion turbine model Sulzer indicated that while their plans are to continue to support the model, other customers operating the current fleet have plans to retire their units over the next 10 years. Sulzer is the sole service provider supporting the RR Olympus combustion turbine generators for NL Hydro and further reductions in the number of units remaining in the operating fleet may continue to increase challenges in securing effective parts and service support.

Sustaining capital forecast plans for operation of the SVL power plant through 2035 versus 2040 are provided in Table 9-2. Details of the recommended Capital Upgrades and Major Maintenance items are discussed in this section and a further breakdown of the estimated costs is provided in Appendix A.3 and A.4.

Table 9-2: SVL Summary of Costs by Scenario ($1000's)

Case		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Total
SVL 2035	Capital	450	6426	4051	546	1197	908	398	410	-	-	-	-	-	-	-	-	$14,385
	Operating	520	536	552	568	585	603	621	640	659	678	699	-	-	-	-	-	$6,660
	Total	**970**	**6,962**	**4,602**	**1,115**	**1,782**	**1,511**	**1,019**	**1,049**	**659**	**678**	**699**	**-**	**-**	**-**	**-**	**-**	**$21,045**
SVL 2040	Capital	450	6426	4051	546	1197	908	398	1024	-	3571	4047	710	664	-	-	-	$23,992
	Operating	520	536	552	568	585	603	621	640	659	678	699	720	741	764	787	810	$10,482
	Total	**970**	**6,962**	**4,602**	**1,115**	**1,782**	**1,511**	**1,019**	**1,664**	**659**	**4,249**	**4,746**	**1,430**	**1,406**	**764**	**787**	**810**	**$34,474**

Note: Capital and Operating costs are escalated by 3% annually in the above forecast.

The sustaining capital forecast for the SVL generating station considers the following refurbishment cycles based on typical asset refurbishment and replacement cycles from Hatch experience in sustaining capital planning for thermal power plants, the historical investment cycle and maintenance requirements of the generating station, issues identified during the condition assessment, and current capital projects in progress or planned by NL Hydro. In some cases, capital projects are deferred to start in 2027 to enable sufficient time for planning, procurement and implementation:

Combustion Turbine Engines: The typical overhaul frequency on the current fleet of RR Olympus engines is between 300 - 500 starts. The NL Hydro fleet is at the lower end of this interval indicating a decline in reliability consistent with advanced age and wear. The sustaining capital profile for SVL assumes 40 starts per year per combustion turbine engine and overhauls every 8 years (after 300 to 350 starts) for each combustion turbine engine. NL Hydro maintains one rotational spare combustion turbine engine. When an overhaul or repair is required the engine is removed and exchanged with the rotational spare and sent offsite for repair or overhaul. The removed engine then becomes the rotational spare available for installation when needed at either of the HWD or SVL power plant sites. NL Hydro has also advised that spare parts support for the engine ignition systems is no longer available; therefore, an ignition system upgrade is included in 2026 in the profile.

Air Intake System: The combustion turbine engine air intake experiences coating deterioration and corrosion due to the environmental conditions on site and requires periodic inspection, metal repairs, and coating refurbishment. Based on the historical investment required, a 10-year interval is included in the profile. NL Hydro advises the next refurbishment works are planned for 2027 based on the current capital plan for the facility. The most recent repairs were indicated to have been completed in 2016. The combustion turbine engine air intake filters also require periodic replacement, and a 5-year air filter replacement cycle is included in the profiles starting in 2030. This is based on NL Hydro operating experience and the most recent replacement year being advised to have been in 2025.

Exhaust Stacks: The combustion turbine exhaust stacks experience coating deterioration and corrosion due to the environmental conditions on site and require periodic inspection, metal repairs, and coating refurbishment. Based on the historical investment required, a 10-year interval is included in the profile. This will start in 2026 as the most recent repairs were indicated to have been completed in 2016.

Engine Lube Oil Systems: NL Hydro has previously identified a need to upgrade the lube oil filter system for the combustion turbine engines due to challenges in sourcing filter media for the original filter housings. The new filter housings have already been sourced, inspected on-site and are scheduled for installation in 2026. This cost is split between 2025 and 2026 in the profile to account for the procurement costs already incurred and is not expected to be incurred again in the remaining life of the power plant in the operating profiles considered.

Compressed Air Systems: NL Hydro advises that the compressed air system was most recently upgraded in 2015. Based on this recent investment timing further upgrades are not anticipated to be required during the remaining plant life based on a typical 30-year upgrade cycle.

Power Turbines: Based on the expected operation of the power plant, A and B side power turbine inspections by Sulzer are recommended on a 10-year basis. It was advised that the most recent inspection was in 2017. This inspection cycle starts in 2027 in the forecast.

SSS Clutches: The SSS clutch service manual indicates that service is required after 1,000 to 1,200 starts. Based on the expected operation of the power plant and number of starts per year this service interval is included in the plan on a 10-year cycle starting in 2027 to align with the power turbine inspection cycle.

Main Lube Oil Cooling System: The main lube oil cooling system is advised to have been upgraded in 2014 and included the replacement of the cooling system air cooled heat exchanger. Based on this recent investment timing, further upgrades are not anticipated to be required during the remaining plant life based on a typical 30-year upgrade cycle. NL Hydro however advised of concerns with corrosion observed to have developed on the air-cooled heat exchanger since replacement. Photos of the underside of the air-cooled heat exchanger show severe coating failure and corrosion on the frame and cross-bracing. Based on this, a 10-year cycle beginning in 2026 has been included for coating and tubing repairs. One of the common failure points on air cooled heat exchangers of this type is at the location where the finned tubes connect to the main headers at either end of the heat exchangers. Thermal fatigue from hot glycol reaching the cold heat exchanger during startup in cold weather conditions and the expansion and contraction of the tubing can cause failure at or near the connection point, requiring repair or cutting and capping of the affected tubes.

Generator: The generator is advised by NL Hydro to have been replaced in 2012. Hatch considers that a 40-year life of the generator can be expected with only cleaning and rewind activities in the event of a failure being required. No further replacement costs are forecast in the profile.

Automatic Voltage Regulator (AVR): The AVR system is advised by NL Hydro to have been upgraded in 2009. Hatch recommends that a 20-year upgrade cycle be considered for the AVR to ensure parts and service support remains available. Based on this an AVR upgrade in 2029 is carried in the profile.

Instrumentation and Control Systems: The balance of plant instrumentation has been subject to select upgrades and replacement over the lifetime of the power plant with upgrades noted to have been completed in 2014, 2015 and 2017. Any Instrumentation which is older than 20 years should be scheduled for replacement due to the risk of being obsolete with limited spare parts support. Older instruments could fail at any time and result in an extended plant shutdown as the original instruments are no longer available, and replacements will require engineering inputs to find a suitable replacement. A 3-year project is considered in the profile starting in 2030 based on the last investment completed to ensure the availability of parts, I/O cards, and instrument support.

Bailey Control System: The combustion turbine control system is an ELSAG Bailey INFI 90 DCS which was installed in 1999 and includes components for which replacement parts are no longer available. The Bailey INFI 90 system is supported by ABB and can be upgraded to a DCS System 800xA. ABB offers a Life Cycle and Migration program which outlines a lifecycle plan. The profile considers a phased 3-year project to update the Bailey Control system starting in 2027 to ensure parts and service support and reliability.

13.8 kV Switchgear (generator breaker): The 13.8 kV generator breaker was upgraded in the year 1999 and a 30-year upgrade cycle is recommended to ensure reliability and the availability of parts and service support. The profiles consider a breaker upgrade in 2030.

Generator Protection Relays: The generator protection relays have been upgraded during the life of the power plant, and a 20-year upgrade cycle is typically recommended to ensure reliability and the availability of parts and service support. However, based on the current condition of the protection relays the profiles consider deferring the protection relay upgrade for another 5 years and it is recommended that this upgrade be combined with the generator breaker upgrade in 2030, and this combined upgrade is considered in the profile.

Motor Control Center (MCC): The motor control center (MCC) which provides AC and DC power distribution to auxiliary systems was replaced in 2015. Based on this and a typical life of 30 years or more with ongoing parts and service support no further replacement is considered in the profile.

125V DC Batteries and Chargers: The 125V DC batteries ensure that uninterrupted control power is available in case of a power loss and to ensure a safe shutdown of the combustion turbine generators can be performed in a blackout condition. The operating life of the 125VDC batteries is typically 10 years before degradation of charge and amp hour storage becomes apparent. The inverter and battery chargers and battery monitoring system can also become a risk of failure and parts and service support, and a replacement/upgrade of this system is recommended on a 20-year interval. The 125 VDC batteries are advised by NL Hydro to be planned for replacement in 2025, and the inverter was advised to have been replaced in 2016. This planned replacement and the recommended replacement intervals are considered in the profiles.

Emergency Back Up Diesel Generator: The emergency generator was advised to have been last replaced in 2006 and to be planned for replacement in 2027. Based on the age of the unit replacement is recommended to ensure sufficient parts and service support. For emergency generators a typical 20-year replacement cycle is recommended, however if the genset model is still in production a control system upgrade could also be considered. The profile considers the planned replacement in 2027.

Auxiliary Transformer (13.8 kV/600 V): The auxiliary transformer which provides 600 V low voltage power to the power plant is the original and has not been replaced during the life of the power plant. No replacement costs are considered in the profile. The transformer would be subject to condition monitoring and transformers of this type are typically able to operate past 50 years in age.

Transformer (66/13.8 kV): The generator step-up transformer which steps up the generator voltage to the terminal station voltage of 66 kV is the original and has not been replaced during the life of the power plant. No replacement costs are considered in the profile as this transformer is outside of the scope of the study.

Fuel Forwarding Equipment: The fuel forwarding equipment was advised to have been last upgraded in 2015. This equipment is comprised of pumps which draw fuel from the fuel storage pump and a high-pressure DC pump which delivers fuel to the combustion turbine engines. The system also includes a fuel viscosity heater which was advised to have been replaced in 2017. Based on this recent investment timing further upgrades are not anticipated to be required during the remaining plant life based on a typical 30-year upgrade cycle.

Fuel Piping: The fuel pipeline between the main storage tank and the fuel forwarding building is advised to have been replaced in 2008. Based on this recent investment timing and findings during the site visit further investment is not considered to be required in the profile. Recoating of the piping is recommended to be planned in 2025 on a 10-year interval, and this cost is included in the profile starting in 2026. During this interval UT thickness measurements can also be performed at spot locations to assess any signs of corrosion and piping wall thickness loss. This should focus on areas near to supports which have a higher failure potential due to the added support load.

Fire Protection and Detection Systems: Fire detection and protection systems typically experience reduced parts and service support over time as key components cease to be manufactured and are no longer available. Historical experience at the power plant has also identified pull station replacements and flex hose replacements to have been required within 20 years of operation of the fire detection systems and Ansul and Inergen fire protection systems installed. Based on this the profiles consider mid-life refurbishment costs in 2026 to address deficiencies, and a 30-year upgrade cost in 2032 based on 2002 being the last year the system was noted to have been upgraded.

GT Enclosures: During the site visits deterioration of the combustion turbine generator package enclosure coating and corrosion was observed. Environmental factors such as severe weather and the proximity of the ocean coastline are known to accelerate coating deterioration and corrosion. Ensuring maintenance of the enclosure coating is essential to preventing corrosion of the combustion turbine generator enclosure package. Should the enclosure become compromised there is the risk that water ingress can cause damage to the combustion turbine engine, power turbine, generator and other auxiliary components. NL Hydro is planning to complete recoating of the enclosure, and this project is shown in the profile for 2026. Based on the past frequency of this work being required, re-performance of this work is recommended and included on a 10-year cycle.

Control Building: During the site visit some staining was observed on the ceiling in the control building which could be resulting from a roof deterioration issue which should be investigated. A 10-year budget cycle is recommended for minor building repairs which is considered in the profile starting in 2026.

HV Breaker Building: A 10-year budget cycle is recommended for minor building repairs which is considered in the profile starting in 2026.

External Garage: A 10-year budget cycle is recommended for minor building repairs which is considered in the profile starting in 2026. Some settling and cracking of the building floor slab was identified during the site visit which should be addressed.

Maintenance Building and Black Start Generator Building: A 10-year budget cycle is recommended for minor building repairs which is considered in the profile starting in 2026.

9.2.1 Summary of Stephenville Sustaining Capital Plan Based on a 2035 Retirement Year

The estimated sustaining capital costs required from 2025 until retirement of the SVL power plant in 2035 are summarized as follows:

- 2025:
  - Air Intake Filter Replacement;
  - Combustion Turbine Engine Lube Oil System Upgrade;
  - Ignition System;
  - Station DC Battery Replacement.
- 2026:
  - Combustion Turbine Engine A Overhaul (Engine #202224 exchanged with #202223);
  - Exhaust Stack Refurbishment;
  - GT Enclosures Refurbishment;
  - Air Cooled Heat Exchanger Repairs;

- Fuel Piping Coating Repairs;
- Fire detection and protection system refurbishment;
- Building Envelope Repairs for Black Start Building, Control Building, HV Breaker Building, Fuel Unloading Building and Fuel Forwarding Building.

- 2027:
  - Combustion Turbine Engine B Overhaul (Engine #202204 exchanged with #202224);
  - Air Inlet System Refurbishment;
  - Power Turbine A and B Inspections;
  - SSS Clutch Service;
  - Bailey Control System Upgrade (year 1);
  - Emergency Generator Replacement.
- 2028:
  - Bailey Control System Upgrade (year 2).
- 2029:
  - AVR Upgrade;
  - Bailey Control System Upgrade (year 3).
- 2030:
  - Air Inlet Filter Replacement;
  - Instrumentation and Control Upgrades (year 1);
  - 13.8 kV Generator Breaker Upgrade;
  - Generator Protection Relays Upgrade.
- 2031:
  - Instrumentation and Control Upgrades (year 2).
- 2032:
  - Instrumentation and Control Upgrades (year 3);
  - Fire detection and protection system upgrade.

The following forecasted works and costs are deferred based on the 2035 retirement year:

- Fire Suppression System Replacement (2032);
- Combustion Turbine Engine A Overhaul (2034);
- Combustion Turbine Engine B Overhaul (2035);
- Air Inlet System Refurbishment (2035);
- Station DC Battery and Inverter Replacement (2035).

9.2.2 Summary of Stephenville Sustaining Capital Plan Based on a 2040 Retirement Year

The estimated sustaining capital costs required from 2025 until retirement of the SVL power plant in 2040 are summarized as follows:

- 2025:
  - Air Intake Filter Replacement;
  - Combustion Turbine Engine Lube Oil System Upgrade;
  - Ignition System;
  - Station DC Battery Replacement.
- 2026:
  - Combustion Turbine Engine A Overhaul (Engine #202224 exchanged with #202223);
  - Exhaust Stack Refurbishment;
  - GT Enclosures Refurbishment;
  - Air Cooled Heat Exchanger Repairs;
  - Fuel Piping Coating Repairs;
  - Fire detection and protection system refurbishment;
  - Building Envelope Repairs for Black Start Building, Control Building, HV Breaker Building, Fuel Unloading Building and Fuel Forwarding Building.
- 2027:
  - Combustion Turbine Engine B Overhaul (Engine #202204 exchanged with #202224);
  - Air Inlet System Refurbishment;
  - Power Turbine A and B Inspections;
  - SSS Clutch Service;
  - Bailey Control System Upgrade (year 1);
  - Emergency Generator Replacement.

- 2028:
  - Bailey Control System Upgrade (year 2).
- 2029:
  - AVR Upgrade;
  - Bailey Control System Upgrade (year 3).
- 2030:
  - Air Inlet Filter Replacement;
  - Instrumentation and Control Upgrades (year 1);
  - 13.8 kV Generator Breaker Upgrade;
  - Generator Protection Relays Upgrade.
- 2031:
  - Instrumentation and Control Upgrades (year 2).
- 2032:
  - Instrumentation and Control Upgrades (year 3);
  - Fire detection and protection system upgrade.
- 2034:
  - Combustion Turbine Engine A Overhaul (Engine #202223 exchanged with #202205).
- 2035:
  - Combustion Turbine Engine B Overhaul (Engine #202224 exchanged with #202223);
  - Air Inlet Filter Replacement;
  - 125V DC Battery and Inverter Replacement.
- 2036:
  - Air Inlet System Refurbishment;
  - Exhaust Stack Refurbishment;
  - Air Cooled Heat Exchanger Repairs;
  - Fuel Piping Coating Repairs;
  - Building Envelope Repairs for Black Start Building, Control Building, HV Breaker Building, Fuel Unloading Building and Fuel Forwarding Building.

- 2037:
  - Power Turbine A and B Inspections;
  - SSS Clutch Service.

The following forecasted works and costs are deferred based on the 2040 retirement year:

- Air Inlet Filter Replacement (2040).

9.3 Recommended Capital Spares

The following capital spares are recommended to be considered for purchase from grey market supply sources and vendors to ensure the reliability of the HWD and SVL power plants. The decision to purchase the below capital spares can be at the discretion of NL Hydro depending on the retirement dates planned for each power plant. Should one power plant be retired earlier, the power turbine capital spares could be sourced from retired and decommissioned units.

Table 9-3: Recommended Additional Capital Spares

Capital Spare Items	Estimated Cost per Item
Curtis Wright Power Turbine, LH Rotation	$900,000
Curtis Wright Power Turbine, RH Rotation	$900,000
HWD MCC Spares	$100,000
Total	**$1,900,000**

During discussions with Sulzer, it was indicated that the turnaround time to source parts and overhaul the power turbines may cause delays of up to 1 year due to limited grey market parts availability. This is outside of the outage times that can be accommodated between key winter and summer operating seasons when the generating units must be available. Securing spare power turbine units will guarantee a parts supply stock, and it was noted by Sulzer that this may improve turnaround times for parts supply to only 3 weeks in the case of a power turbine failure or risk of imminent failure identified during inspections.

Eaton was requested to provide quotations for the replacement of the HWD MCCs through either the complete replacement of the two HWD MCCs, or the upgrade of the MCCs through retrofitting new buckets with modernized components currently in production as an aftermarket upgrade. As indicated in earlier section original replacement parts for the HWD MCC are no longer available and are therefore often custom-built, which presents risks related to lead times, cost and long-term support. If the HWD MCCs are not replaced as a sustaining capital upgrade during the time frame recommended in the sustaining capital plan, spare MCC buckets for each starter and feeder breaker size are recommended to be purchased to support continued operation and reduce outage times in case of an MCC failure.

9.4 Retirement

To determine the optimal retirement timeline for aging generating assets, it is essential to consider both their operational roles and their ability to meet current reliability expectations. The HWD and SVL stations are required to support the grid as backup and emergency generation and by providing synchronous condensing services. However, due to their advanced age, increasing maintenance demands, and declining reliability, the capability of each power plant to operate dependably in the event of a prolonged outage of the Labrador-Island Link is assessed to be at risk.

While the combustion turbine overhaul and repair cycles are indicated to be primarily number of starts driven, the combustion turbine units are also operating for only an average of 500 hours between repairs and overhauls and therefore their endurance to operate continuously for 1 month (720 hours) or greater is uncertain. Based on this reliability performance, continued reliance on these assets is assessed to pose a risk to system reliability. It is therefore recommended that the HWD power plant be retired as soon as practicable, with a target retirement date of 2035. To support a cost-based retirement year analysis, the cumulative sustaining capital and operating costs from 2025 to each potential retirement year (from 2030 to 2040) for both HWD and SVL are shown in Table 9-4. This analysis assumes that there would be no capital expenditures for the two years leading up to retirement.

Table 9-4: HWD, and SVL Cumulative Capital and Operating Costs ($1000's from 2030 to 2040)

Year	HWD			SVL		
	Capital	Operating	Total Cost	Capital	Operating	Total Cost
2030	$15,196	$3,364	$18,560	$11,473	$3,364	$14,837
2031	$16,134	$3,984	$20,118	$12,670	$3,984	$16,654
2032	$19,306	$4,624	$23,930	$13,578	$4,624	$18,202
2033	$19,306	$5,283	$24,589	$13,975	$5,283	$19,258
2034	$22,672	$5,961	$28,633	$14,385	$5,961	$20,346
2035	**$22,799**	**$6,660**	**$29,459**	**$14,385**	**$6,660**	**$21,045**
2036	$27,424	$7,380	$34,804	$18,570	$7,380	$25,950
2037	$27,765	$8,121	$35,886	$22,618	$8,121	$30,739
2038	$31,762	$8,885	$40,647	$23,328	$8,885	$32,213
2039	$32,397	$9,671	$42,069	$23,992	$9,671	$33,664
2040	**$36,899**	**$10,482**	**$47,380**	**$23,992**	**$10,482**	**$34,474**

Retirement of the HWD power plant in 2035 is seen to avoid significant sustaining capital costs of approximately $14,100,000 that would otherwise be required during the remaining operating period and is therefore considered to be an optimal retirement year. In contrast, the SVL power plant may continue operating until 2040, supported by the availability of additional spare parts from HWD, which can help sustain its reliability in the interim. This staggered retirement approach balances asset condition and capital planning priorities and can help to balance the NL Hydro system needs. An alternative approach of retirement of the SVL power plant in 2035 to provide spare parts supply support to HWD for operation through 2040 can also be considered. However, based on the more recent investments in SVL, the condition of the HWD power plant, and higher sustaining capital costs forecast for HWD from 2035 to 2040, this is not considered to be the most optimal or suitable option.

During the 5 years leading up to the 2035 HWD and 2040 SVL retirement dates potential replacement of the power plant facilities with new combustion turbine generator units may be considered and planned depending on the system capacity and synchronous condensing needs at each power plant location. This planning time period is recommended to avoid any gaps in system capacity.

These recommendations are based solely on the assessed condition of the individual assets, and the outlook for parts and service availability. The recommended retirement dates are not based on a technical operating life limit and do not consider the wider NL Hydro system needs, cost impacts, or timing for other system asset retirement or new asset development. Due to the age of the power plant facilities, continued operation beyond the recommended retirement dates is considered to present an elevated risk of prolonged outages and availability impacts in the event there is limited parts and service availability to address unplanned and planned repairs and maintenance.

10. Conclusion and Recommendations

The typical median expected operating life of a liquid fuel operated aeroderivative combustion turbine peaking power plant is 25 years when a proper preventative maintenance program has been implemented. Operating lifetimes beyond 25 years for thermal power generation assets are possible and have been achieved as can be seen within NL Hydro’s facilities currently in operation, however on a long-term planning basis the availability of parts and service support beyond this period can be uncertain. HWD and SVL were commissioned in 1976 and 1975 and therefore have provided 50+ years of service. With significant capital investment HWD and SVL have been able to operate 20+ years beyond the median operating life of similar stations.

Based on the findings of this report the capability of each power plant to operate dependably in the event of a prolonged outage of the Labrador-Island Link is assessed to be at risk, particularly during prolonged outages of the Labrador-Island Link or in extreme conditions such as a heat wave, forest fires or freezing rain. Their availability under high stress or extended runtime scenarios cannot be assured. It is therefore recommended that the HWD power plant be retired as soon as practicable, with a target retirement date of 2035. In contrast, the SVL power plant may continue operating until 2040, supported by the availability of additional spare parts from HWD, which can help sustain its reliability in the interim. This staggered retirement approach balances system needs, asset condition, and capital planning priorities.

The recommended retirement dates are not based on a technical operating life limit and do not consider the wider NL Hydro system needs, cost impacts, or timing for other system asset retirement or new asset development. These recommendations are based solely on the assessed condition of the individual assets, and the outlook for parts and service availability, which are considered to pose an elevated risk of prolonged outages and availability impacts.

Appendix A
Sustaining Capital and OPEX Cost Summary

A.1 Hardwoods Retirement in 2035

Hardwoods 2035 Retirement	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Gas Generator Engines and Subsystems Unit A	-	26	-	2,990	-	-	-	3,366	-	-	-	$ 6,382
Gas Generator Engines and Subsystems Unit B	-	2,844	-	-	-	3,172	-	-	-	-	-	$ 6,017
Gas Generator Engines Lube Oil System	25	26	-	-	-	-	-	-	-	-	-	$ 51
Compressed Air System	25	103	-	-	-	-	-	-	-	-	-	$ 128
Air Inlet System	149	-	-	109	-	-	-	-	127	-	-	$ 385
Exhaust Stacks	-	-	-	250	-	-	-	-	-	-	-	$ 250
Ignition System	-	283	-	-	-	-	-	-	-	-	-	$ 283
Curtiss Wright Power Turbine	-	-	106	-	-	-	-	-	-	-	-	$ 106
Curtiss Wright Power Turbine	-	-	106	-	-	-	-	-	-	-	-	$ 106
SSS Power Turbine Clutches	-	-	62	-	-	-	-	-	-	-	-	$ 62
SSS Power Turbine Clutches	-	-	62	-	-	-	-	-	-	-	-	$ 62
Main Lube Oil Cooling System / Glycol Cooler	-	-	2,081	-	-	-	-	-	-	-	-	$ 2,081
Generator	-	-	-	-	-	-	-	-	-	-	-	$ -
Automatic Voltage Regulator (AVR)	-	-	-	-	-	-	-	-	-	-	-	$ -
Instrumentation and Control Systems	-	-	354	364	375	-	-	-	-	-	-	$ 1,093
Bailey Control System	-	-	530	546	563	-	-	-	-	-	-	$ 1,640
13.8 kV Switchgear (generator breaker)	-	-	-	-	-	-	-	-	-	-	-	$ -
Generator protection relays	-	-	-	-	-	-	-	-	-	-	-	$ -
Motor Control Centres (AC & DC)	-	1,118	1,151	-	-	-	-	-	-	-	-	$ 2,269
Station DC supply (batteries and chargers)	-	129	-	-	-	-	-	-	-	-	-	$ 129
Inverter (AC supply for control systems)	-	-	-	-	-	-	-	-	-	-	-	$ -
Emergency Backup Diesel Generator	-	-	123	-	-	-	-	-	-	-	-	$ 123
Transformer (13.8kV/600)	-	-	-	-	-	-	-	-	-	-	-	$ -
Transformer (66/13.8kV)	-	-	-	-	-	-	-	-	-	-	-	$ -
Fuel Unloading Pumps	-	-	106	-	-	-	-	-	-	-	-	$ 106
Fuel Forwarding Equipment	-	-	1,228	-	-	-	-	-	-	-	-	$ 1,228
Fuel Piping	-	-	-	-	-	-	-	-	-	-	-	$ -
Fuel Piping Coating	50	-	-	-	-	-	-	-	-	-	-	$ 50
Fire Fighting Systems	-	-	-	-	-	-	-	-	-	-	-	$ -
Fire Fighting Systems Mid Life Refurbishment	-	31	-	-	-	-	-	-	-	-	-	$ 31
Fuel Viscosity Heater	-	-	-	-	-	-	-	-	-	-	-	$ -
Auxiliary Module Building Envelope	-	27	-	-	-	-	-	-	-	-	-	$ 27
GT Enclosures	54	-	-	-	-	-	-	-	-	-	-	$ 54
Maintenance and Parts Storage Building Envelope	-	-	-	-	-	-	-	-	-	-	-	$ -
Blackstart Building	-	-	28	-	-	-	-	-	-	-	-	$ 28
Control Building	-	-	28	-	-	-	-	-	-	-	-	$ 28
HV Breaker Building	-	-	28	-	-	-	-	-	-	-	-	$ 28
Fuel Unloading Building envelope	-	-	27	-	-	-	-	-	-	-	-	$ 27
Fuel Forwarding Building envelope	-	-	27	-	-	-	-	-	-	-	-	$ 27
Total Capital	**304**	**4,587**	**6,046**	**4,260**	**938**	**3,172**	**-**	**3,366**	**127**	**-**	**-**	**$ 22,799**
Total Operating	**520**	**536**	**552**	**568**	**585**	**603**	**621**	**640**	**659**	**678**	**699**	**$ 6,660**
Total	**824**	**5,122**	**6,597**	**4,828**	**1,523**	**3,775**	**621**	**4,005**	**785**	**678**	**699**	**$ 29,459**

Escalation Factor	3%
Base Year	2025

A.2 Hardwoods Retirement in 2040

Hardwoods 2040 Retirement	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Total
Gas Generator Engines and Subsystems Unit A	-	26	-	2,990	-	-	-	3,366	-	-	-	3,788	-	-	-	-	$ 10,170
Gas Generator Engines and Subsystems Unit B	-	2,844	-	-	-	3,172	-	-	-	3,571	-	-	-	4,019	-	-	$ 13,606
Gas Generator Engines Lube Oil System	25	26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 51
Compressed Air System	25	103	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 128
Air Inlet System	149	-	-	109	-	-	-	-	127	-	201	-	-	147	-	-	$ 733
Exhaust Stacks	-	-	-	250	-	-	-	-	-	-	-	-	-	336	-	-	$ 586
Ignition System	-	283	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 283
Curtiss Wright Power Turbine	-	-	106	-	-	-	-	-	-	-	-	-	143	-	-	-	$ 249
Curtiss Wright Power Turbine	-	-	106	-	-	-	-	-	-	-	-	-	143	-	-	-	$ 249
SSS Power Turbine Clutches	-	-	62	-	-	-	-	-	-	-	-	-	83	-	-	-	$ 145
SSS Power Turbine Clutches	-	-	62	-	-	-	-	-	-	-	-	-	83	-	-	-	$ 145
Main Lube Oil Cooling System / Glycol Cooler	-	-	2,081	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 2,081
Generator	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ -
Automatic Voltage Regulator (AVR)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ -
Instrumentation and Control Systems	-	-	354	364	375	-	-	-	-	-	-	-	-	-	-	-	$ 1,093
Bailey Control System	-	-	530	546	563	-	-	-	-	-	-	-	-	-	-	-	$ 1,640
13.8 kV Switchgear (generator breaker)	-	-	-	-	-	290	-	-	-	-	-	-	-	-	-	-	$ 290
Generator protection relays	-	-	-	-	-	116	-	-	-	-	-	-	-	-	-	-	$ 116
Motor Control Centres (AC & DC)	-	1,118	1,151	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 2,269
Station DC supply (batteries and chargers)	-	129	-	-	-	-	-	-	-	-	-	173	-	-	-	-	$ 302
Inverter (AC supply for control systems)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ -
Emergency Backup Diesel Generator	-	-	123	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 123
Transformer (13.8kV/600)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ -
Transformer (66/13.8kV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ -
Fuel Unloading Pumps	-	-	106	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 106
Fuel Forwarding Equipment	-	-	1,228	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 1,228
Fuel Piping	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ -
Fuel Piping Coating	50	-	-	-	-	-	-	-	-	-	67	-	-	-	-	-	$ 117
Fire Fighting Systems	-	-	-	-	-	-	-	615	-	-	-	-	-	-	-	-	$ 615
Fire Fighting Systems Mid Life Refurbishment	-	31	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 31
Fuel Viscosity Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ -
Auxiliary Module Building Envelope	-	27	-	-	-	-	-	-	-	-	-	36	-	-	-	-	$ 63
GT Enclosures	54	-	-	-	-	-	-	-	-	-	73	-	-	-	-	-	$ 127
Maintenance and Parts Storage Building Envelope	-	-	-	-	-	-	-	-	-	34	-	-	-	-	-	-	$ 34
Blackstart Building	-	-	28	-	-	-	-	-	-	-	-	-	37	-	-	-	$ 65
Control Building	-	-	28	-	-	-	-	-	-	-	-	-	37	-	-	-	$ 65
HV Breaker Building	-	-	28	-	-	-	-	-	-	-	-	-	37	-	-	-	$ 65
Fuel Unloading Building envelope	-	-	27	-	-	-	-	-	-	-	-	-	36	-	-	-	$ 62
Fuel Forwarding Building envelope	-	-	27	-	-	-	-	-	-	-	-	-	36	-	-	-	$ 62
Total Capital	**304**	**4,587**	**6,046**	**4,260**	**938**	**3,578**	**-**	**3,981**	**127**	**3,605**	**341**	**3,997**	**635**	**4,501**	**-**	**-**	**$ 36,899**
Total Operating	**520**	**536**	**552**	**568**	**585**	**603**	**621**	**640**	**659**	**678**	**699**	**720**	**741**	**764**	**787**	**810**	**$ 10,482**
Total	**824**	**5,122**	**6,597**	**4,828**	**1,523**	**4,181**	**621**	**4,620**	**785**	**4,283**	**1,040**	**4,717**	**1,377**	**5,265**	**787**	**810**	**$ 47,380**

Escalation Factor	3%
Base Year	2025

A.3 Stephenville Retirement in 2035

Stephenville 2035 Retirement	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Total
Gas Generator Engines and Subsystems Unit A (202224)	-	2,819	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 2,819
Gas Generator Engines and Subsystems Unit B (202204)	-	-	2,903	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 2,903
Gas Generator Engines Lube Oil System	25	26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 51
Compressed Air System	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ -
Air Inlet System	100	-	158	-	-	116	-	-	-	-	-	-	-	-	-	-	$ 374
Exhaust Stacks	-	235	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 235
Ignition System	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 200
Curtiss Wright Power Turbine	-	-	106	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 106
Curtiss Wright Power Turbine	-	-	106	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 106
SSS Power Turbine Clutches	-	-	62	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 62
SSS Power Turbine Clutches	-	-	62	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 62
Main Lube Oil Cooling System / Glycol Cooler	-	26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 26
Generator	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ -
Automatic Voltage Regulator (AVR)	-	-	-	-	634	-	-	-	-	-	-	-	-	-	-	-	$ 634
Instrumentation and Control Systems	-	-	-	-	-	386	398	410	-	-	-	-	-	-	-	-	$ 1,193
Bailey Control System	-	-	530	546	563	-	-	-	-	-	-	-	-	-	-	-	$ 1,640
13.8 kV Switchgear (generator breaker)	-	-	-	-	-	290	-	-	-	-	-	-	-	-	-	-	$ 290
Generator protection relays	-	-	-	-	-	116	-	-	-	-	-	-	-	-	-	-	$ 116
Motor Control Centres (AC & DC)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ -
Station DC supply (batteries and chargers)	125	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 125
Inverter (AC supply for control systems)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ -
Emergency Backup Diesel Generator	-	-	123	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 123
Transformer (13.8kV/600)	-	773	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 773
Transformer (66/13.8kV)	-	2,250	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 2,250
Fuel Forwarding Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ -
Fuel Piping Coating	-	52	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 52
Fire Fighting Systems	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ -
Fire Fighting Systems Mid Life Refurbishment	-	31	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 31
Fuel Viscosity Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ -
GT Enclosures	-	56	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 56
Maintenance and Parts Storage Building Envelope	-	27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 27
Blackstart Building	-	27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 27
Control Building	-	52	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 52
HV Breaker Building	-	27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 27
External Garage	-	27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 27
Total Capital	**450**	**6,426**	**4,051**	**546**	**1,197**	**908**	**398**	**410**	-	-	-	-	-	-	-	-	**$ 14,385**
Total Operating	**520**	**536**	**552**	**568**	**585**	**603**	**621**	**640**	**659**	**678**	**699**	-	-	-	-	-	**$ 6,660**
Total	**970**	**6,962**	**4,602**	**1,115**	**1,782**	**1,511**	**1,019**	**1,049**	**659**	**678**	**699**	-	-	-	-	-	**$ 21,045**
Escalation Factor	3%																
Base Year	2025																

A.4 Stephenville Retirement in 2040

Stephenville 2040 Retirement	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Total
Gas Generator Engines and Subsystems Unit A (202224)	-	2,819	-	-	-	-	-	-	-	3,571	-	-	-	-	-	-	$ 6,389
Gas Generator Engines and Subsystems Unit B (202204)	-	-	2,903	-	-	-	-	-	-	-	3,678	-	-	-	-	-	$ 6,581
Gas Generator Engines Lube Oil System	25	26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 51
Compressed Air System	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ -
Air Inlet System	100	-	158	-	-	116	-	-	-	-	134	-	213	-	-	-	$ 721
Exhaust Stacks	-	235	-	-	-	-	-	-	-	-	-	316	-	-	-	-	$ 552
Ignition System	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 200
Curtiss Wright Power Turbine	-	-	106	-	-	-	-	-	-	-	-	-	143	-	-	-	$ 249
Curtiss Wright Power Turbine	-	-	106	-	-	-	-	-	-	-	-	-	143	-	-	-	$ 249
SSS Power Turbine Clutches	-	-	62	-	-	-	-	-	-	-	-	-	83	-	-	-	$ 145
SSS Power Turbine Clutches	-	-	62	-	-	-	-	-	-	-	-	-	83	-	-	-	$ 145
Main Lube Oil Cooling System / Glycol Cooler	-	26	-	-	-	-	-	-	-	-	-	35	-	-	-	-	$ 60
Generator	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ -
Automatic Voltage Regulator (AVR)	-	-	-	-	634	-	-	-	-	-	-	-	-	-	-	-	$ 634
Instrumentation and Control Systems	-	-	-	-	-	386	398	410	-	-	-	-	-	-	-	-	$ 1,193
Bailey Control System	-	-	530	546	563	-	-	-	-	-	-	-	-	-	-	-	$ 1,640
13.8 kV Switchgear (generator breaker)	-	-	-	-	-	290	-	-	-	-	-	-	-	-	-	-	$ 290
Generator protection relays	-	-	-	-	-	116	-	-	-	-	-	-	-	-	-	-	$ 116
Motor Control Centres (AC & DC)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ -
Station DC supply (batteries and chargers)	125	-	-	-	-	-	-	-	-	-	168	-	-	-	-	-	$ 293
Inverter (AC supply for control systems)	-	-	-	-	-	-	-	-	-	-	67	-	-	-	-	-	$ 67
Emergency Backup Diesel Generator	-	-	123	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 123
Transformer (13.8kV/600)	-	773	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 773
Transformer (66/13.8kV)	-	2,250	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 2,250
Fuel Forwarding Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ -
Fuel Piping Coating	-	52	-	-	-	-	-	-	-	-	-	69	-	-	-	-	$ 121
Fire Fighting Systems	-	-	-	-	-	-	-	615	-	-	-	-	-	-	-	-	$ 615
Fire Fighting Systems Mid Life Refurbishment	-	31	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ 31
Fuel Viscosity Heater	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ -
GT Enclosures	-	56	-	-	-	-	-	-	-	-	-	75	-	-	-	-	$ 131
Maintenance and Parts Storage Building Envelope	-	27	-	-	-	-	-	-	-	-	-	36	-	-	-	-	$ 63
Blackstart Building	-	27	-	-	-	-	-	-	-	-	-	36	-	-	-	-	$ 63
Control Building	-	52	-	-	-	-	-	-	-	-	-	69	-	-	-	-	$ 121
HV Breaker Building	-	27	-	-	-	-	-	-	-	-	-	36	-	-	-	-	$ 63
External Garage	-	27	-	-	-	-	-	-	-	-	-	36	-	-	-	-	$ 63
Total Capital	**450**	**6,426**	**4,051**	**546**	**1,197**	**908**	**398**	**1,024**	**-**	**3,571**	**4,047**	**710**	**664**	**-**	**-**	**-**	**$ 23,992**
Total Operating	**520**	**536**	**552**	**568**	**585**	**603**	**621**	**640**	**659**	**678**	**699**	**720**	**741**	**764**	**787**	**810**	**$ 10,482**
Total	**970**	**6,962**	**4,602**	**1,115**	**1,782**	**1,511**	**1,019**	**1,664**	**659**	**4,249**	**4,746**	**1,430**	**1,406**	**764**	**787**	**810**	**$ 34,474**

Escalation Factor	3%
Base Year	2025

Appendix B
Document Register

Document Register Index #	File Name	Description
1	HWD & SVL Major Upgrades .docx	HWD & SVL Major Upgrades
8	PER Form Stantec air intakes inspection .doc	PURCHASING EXCEPTION REPORT GOODS, SERVICES & WORK
12	pro_rtw_20150610_Air_Intake_Condition_Assessment.pdf	-
13	Requisition Air Intakes inspection.xlsx	Proposal for Engineering Services - Gas Turbine Air Intake Condition Assessment for Stephenville & Hardwoods
14	res_peter_lee.pdf	Peter Lee Resume
15	rpt_20150813_pl_inlet_inspection_repot_prelim.pdf	Visual Inspection of Inlet Air System GGA (A)
16	Brush Alt Inspection PER.doc	PURCHASING EXCEPTION REPORT GOODS, SERVICES & WORK
17	Brush Alt Inspection Requisition - Purchasing.xlsx	Inspection Report
18	New Operating Project Request 218401.xls	Operating Project Form
21	202224 site recommendations.pdf	Site Reccomendations
22	Cahill Plasma Cutting Purchasing Requisition.xlsx	REQUISITION/RELEASE
23	Copy of Purchasing Requisition - Blank.xlsx	REQUISITION/RELEASE
24	Copy of Standard Project Estimating Template Hydro 2017.xlsm	Standard Project Estimating Template
25	mmt.pdf	Material Movement Ticket
26	PER Form HWD Stack Inspection.doc	PURCHASING EXCEPTION REPORT GOODS, SERVICES & WORK
27	Repair Materials 409 Purchasing Requisition - Blank.xlsx	REQUISITION/RELEASE
28	Repair Materials Purchasing Requisition - Blank.xlsx	REQUISITION/RELEASE
29	PER Form HWD Stack Inspection.doc	PURCHASING EXCEPTION REPORT GOODS, SERVICES & WORK
30	Requisition HWD Stack Inspection.xls	REQUISITION/RELEASE
31	133546845D3301-R0.pdf	Exhaust Stack "B" Modifications and Temporary Repari Sctions, Details and Elevations
32	PER Form HWD Stack Repair Procedure.doc	PURCHASING EXCEPTION REPORT GOODS, SERVICES & WORK
33	Stantec Repair Purchasing Requisition.xlsx	REQUISITION/RELEASE
34	Copy of Purchasing Requisition - Blank.xlsx	PURCHASING EXCEPTION REPORT GOODS, SERVICES & WORK
35	PER Form (Goods, Services and Work).doc	REQUISITION/RELEASE
36	SVLGT,Generator Inspection report -20118.pdf	Brush Aftermarket Service Engineers Site Report
37	Stephenville Stator Final Report 12B810.pdf	Brush Aftermarket Service Engineers Site Report - Major Overhaul and Stator Rewind
38	Thermal Condition Assessment PCN.docx	PCN - Thermal Generation Assessment for Longer Term Viability
39	Thermal Condition Assessment PCN.pdf	PCN - Thermal Generation Assessment for Longer Term Viability
40	Project Report Volume III.pdf	Hatch Project Report - Hardwoods and Stephenville Viability Assessment
43	TRIBRPT.pdf	AGAT Labratories Oil Preventitve Maintenance Analsysis
44	2007 Stantec Condition Assessment (HWD & SVL).pdf	INAL REPORT CONDITION ASSESSMENT AND LIFE CYCLE COST ANALYSIS HARDWOODS AND STEPHENVILLE GAS TURBINE FACILITIES
45	GT Measures.pptx	Generation Reliability Measures – Gas Turbines
46	H365408-00000-100-066-0001 Volume 3 report.pdf	Hatch Project Report - Hardwoods and Stephenville Viability Assessment
47	H365408-00000-210-066-0001_Rev 1 (1).pdf	Hatch Project Report - Hardwoods and Stephenville Viability Assessment
48	H365408-00000-210-066-0001_Rev 1.pdf	Hatch Project Report - Hardwoods and Stephenville Viability Assessment
49	HWD Single Line.pdf	System Operatingh Diagram -HardwoodsTerminal Station
50	SVL Single Line.pdf	System Operatingh Diagram - Stephenville Terminal Station
51	Hardwoods Gas Turbine Cooling System Analysis Report-Rev0.pdf	Stantec - Cooling System Analysis
52	HRDCT2-HAT-49327-EN-CAL-0002-01 Rev A0.pdf	Hydraulic Calculation - Fire Water Supply
53	101742 OS Evaluation Matrix.xlsx	Evaluation of Respondents
54	RFP GT LECA Study - HWD & SVL.docx	RFP GT Study
55	Insurance Document Summary.xlsx	Insurance Doc Summary
56	1944245, HWDGT, BATTERY PM JAN19,24 TB.pdf	Maintenance and Work Order Report
57	2022 Hatch HWD-SVL Condition Assessment Report Volume III.pdf	Hatch Project Report - Hardwoods and Stephenville Viability Assessment
58	2024 Operating Data.xlsx	Operating Data
59	GGA LUBE SYSTEM_ENGINE.pdf	AGAT Labratories Oil Preventitve Maintenance Analysis
60	GGB LUBE SYSTEM_ENGINE.pdf	AGAT Labratories Oil Preventitve Maintenance Analsysis
61	HARDWOODS OVERSPEED PROTECTION ANNUAL P_2.doc	Overspeed protection
62	MAIN LUBE OIL (MLO) SYSTEM_LUBE OIL.pdf	AGAT Labratories Oil Preventitve Maintenance Analsysis

Document Register Index #	File Name	Description
63	2024 07 NL Hydro Hardwoods Auxiliary Module Inergen Report.pdf	Special Hazards Inspection Report
64	2024 07 NL Hydro Hardwoods Fuel Offloading Inergen Report.pdf	Special Hazards Inspection Report
65	2024 07 NL Hydro Hardwoods Generator Module Inergen Report.pdf	Special Hazards Inspection Report
66	2024 07 NL Hydro Hardwoods Turbine A Inergen Report.pdf	Special Hazards Inspection Report
67	2024 07 NL Hydro Hardwoods Turbine B Inergen Report.pdf	Special Hazards Inspection Report
68	2024 07 NL Hydro Hardwoods Turbine Control Module Inergen Report.pdf	Special Hazards Inspection Report
69	Hardwoods API Tank Inspection Report 09032015.pdf	Special Hazards Inspection Report
70	1944085, SVLTS, 250V BATTERY PM MAINT, JAN 08, 24, TB.pdf	Special Hazards Inspection Report
71	2022 Hatch HWD-SVL Condition Assessment Report Volume III.pdf	Special Hazards Inspection Report
72	2024 Operating Data.xlsx	Operating Data
73	GGA LUBE SYSTEM_ENGINE.pdf	AGAT Labratories Oil Preventitve Maintenance Analsysis
74	GGB LUBE SYSTEM_ENGINE Turbine.pdf	AGAT Labratories Oil Preventitve Maintenance Analsysis
75	MAIN LUBE OIL (MLO) SYSTEM_TURBINE.pdf	Maintenance and Work Order Report
76	Olympus_C-202204 Report.docx	Detailed Borescope Report
77	SVLGT OVERSPEED TRIPS 2023.PDF	Overspeed Trips
78	K&D Pratt Invoice (Stephenville) 299329.pdf	Inspection Invoice
79	NL Hydro Stephenville Turbine Repair Verification Letter.pdf	Repairs Invoice
80	EXT-12031-NL2021-021 Stephenville 35A.pdf	In service Inspection Report
81	EXT-12031-NL2021-022 Stephenville 35B.pdf	In service Inspection Report
82	EXT-12031-NL2021-023 Stephenville 35C.pdf	In service Inspection Report
83	NL Hydro Tank No.35a Rev 1, Stephenville, NL.PDF	Acuren Inspection Report
84	NL Hydro Tank No.35b Rev 1 , Stephenville, NL.PDF	Acuren Inspection Report
85	NL Hydro Tank No.35c Rev 1 , Stephenville, NL.PDF	Acuren Inspection Report
86	319-C-008.pdf	Stephenville Gas Turbine Gen Station Site Layout
87	333-c-073.pdf	Hardwoods Terminal Station and Gas Turbine Site Layout
88	2015-2025 Operating Totals Report - GES.pdf	Operating Totals
89	2015-2025 Unit Statistics Report - GES.pdf	Unit Statisitics
90	319-C-001.pdf	Location Plan for Proposed Gas Turbine Installation Stephenville
91	319-C-003.pdf	Stephenville Gas Turbo Gen Station Site Survey
92	319-C-004.pdf	Stephenville Gas Turbon Gen Station Site Layout
93	319-C-005.pdf	Stephenville Gas Turbon Gen Station Site Layout & Transmission Line
94	319-C-008.pdf	Stephenville Gas Turbon Gen Station Site Layout
95	JP 09-56 NL Hydro Hardwoods Terminal Station - 2024 SPHZD SYSTEM DEF REPAIR QUOTE - OCT	-
96	2024 07 NL Hydro Hardwoods Fuel Forwarding Pump House Inergen Report	-
97	Stantec Cond Assess Study2007 HwdsSvl - Printed.pdf	-
98	OoPEC_rtw_20150610_Gas Turbine air Intake Condition Assessment	-
99	BBGMS15128AT2703, 8K Hrs Inspect & Jacking Oil Sys Inspect-quote)	-
100	CO_5166_Report_ BP_Remove_ 202205_Install_202040 - Copy2	-
101	Alba_5269_Newfoundland_Hydro_Stephenville_Investigation_	-
102	pro_pl_20170427_Exhaust_Stacks_Condition_Assessment-signed	-
103	Stantec Repair Purchasing Requisition CO	-
104	HWD & SVL Life Extension Condition Assessment Scope Statement REV 1	-
105	HWD & SVL Life Extension Condition Assessment Scope Statement REV 2	-
106	The Condition Assessment and Life Cycle Cost Analysis of the Hardwoods and Stephenville	-
107	HTGS Life Extension Condition Assessment Scope Statement GT Feb 6 2021_Draft	-
108	H365408-00000-210-066-0001 Vol.III Report Rev 0A_April_14_2022.pdf	-
109	HWD & SVL Major Upgrades .docx	-
110	HWD SVL 2018 to 2021 Oct.xlsx	-

Document Register Index #	File Name	Description
111	HWD SVL 2021 Budget markup.xlsx	-
112	HWDGT & SVLGT Operating HRS 2010-2020.xlsx	-
113	LECA Comments RS 01-21-2022.docx	-
114	1391058,HWDGT,GENERATOR ANNUAL INSPECT APR26,19 TB.pdf	-
115	1392307, HWDGT, GEN RE-DOBLE (2020), JUN. 09, 20.pdf	-
116	1Hardwoods Site Report Customer Copy.pdf	-
117	HWD Failures Since 2016.docx	-
118	HWD GT TEMPERATURE TRENDING REV 1.docx	-
119	HWDGT Operating Data Jan 2011-Sept 2021.docx	-
120	NL HYDRO API 653 HARDWOOD Tank #1 June 2015.pdf	-
121	NL Hydro Tank No.35a Rev 1, Stephenville, NL.PDF	-
122	NL Hydro Tank No.35b Rev 1 , Stephenville, NL.PDF	-
123	NL Hydro Tank No.35c Rev 1 , Stephenville, NL.PDF	-
124	rpt_20150813_pl_inlet_inspection_repot_prelim.pdf	-
125	SVL Generator Inspection Report 2018.pdf	-
126	2013 11 14, SVLGT Monthly Testting.pdf	-
127	43 Review Oct 14.pdf	-
128	43 settlement letter.pdf	-
129	Alba_4117_NFH_Olympus_202223_Investigation_09_05_2014.pdf	-
130	Alba_4117_Progress report 1.pdf	-
131	Engine 202223 Summary document.docx	-
132	Engine Events Timeline.docx	-
133	EYNON Douglas - CV.PDF	-
134	Installation Report - 202223 and 202224 - May 2013.pdf	-
135	Jan 08 2014 trip trends_Part1.pdf	-
136	Jan 08 2014 trip trends_Part2.pdf	-
137	Jan 08 2014 trip trends_Part3.pdf	-
138	Newfoundland Hydro Olympus 202223 CO4117 Formatted.pdf	-
139	NL Hydro Report - Rev 0 for Issue.docx	-
140	Olympus Failure Investigation Closing Report - Alberta Issue AM edits.docx	-
141	PER Form Alba Power Ltd Warranty repair.doc	-
142	PER Form AMEC RCA.doc	-
143	Requisition AMEC Eng Support RCA.xlsx	-
144	Requisition Warranty repair Alba Power.xlsx	-
145	SKM_C364e15021913450.pdf	-
146	SKM_C364e15021914350.pdf	-
147	SKM_C364e15021914351.pdf	-
148	SKM_C364e15021914352.pdf	-
149	Summary of Consultant findings.docx	-
150	Summary of exceptions Alba 2011 48141.docx	-
151	Olympus C rate nominal Accel_Decel Curves.pdf	-
152	202224 site recommendations.pdf	-
153	CO 4744 202224_202040.pdf	-
154	R.C.A report 202224.pdf	-
155	Section 1 - Executive Summary.pdf	-
156	Section 10 - Engine Certificate of Conformity.pdf	-
157	Section 2 - 202224 - Receipt Inspection Report.pdf	-
158	Section 3 - 202224 - Bulk Strip Report.pdf	-
159	Section 4 - 202224 - Detail Strip Inspection Report.pdf	-
160	Section 5 - 1 Progress report - 202224 - 23-10-2015.pdf	-
161	Section 5 - 2 Progress report - 202224 - 30-10-2015.pdf	-
162	Section 5 - 3 Progress report - 202224 - 13-11-15.pdf	-
163	section 6 - Scrap Lists.pdf	-
164	Section 8 - Accessories Certificate of Conformity.pdf	-
165	Section 8 - Balance Certificates.pdf	-
166	Section 8 - Bearings Certificate of Conformity.pdf	-
167	Section 8 - Coating Certificate of Conformity.pdf	-
168	Section 8 - Engine Summary Test Certificate.pdf	-
169	Section 8 - Fuel Nozzles.pdf	-
170	Section 8 - Modifications.pdf	-
171	Section 9 - Engine Performance Test Results.pdf	-

Document Register Index #	File Name	Description
172	1_Root Cause Analysis Process_25_04_2016.pdf	-
173	Alba_5269_Newfoundland_Hydro_Stephenville_Investigation_.pdf	-
174	Alba_5269_Newfoundland_Hydro_Stephenville_Investigation_29_03_16 .pdf	-
175	Alba_5593_ Nefoundland Hydro_202204 Commissioning_27_03_2017.pdf	-
176	Alba_5593_Nefoundland Hydro 202224 Inspection_24_03_2017.pdf	-
177	Alba_5840_202224_Newfoundland hydro test Report_15_11_2017.pdf	-
178	Alba_5840_Newfoundland Hydro_202224_Bulk Strip Report_21_09_2017.pdf	-
179	Alba_6816_202223_Newfoundland Hydro_Final Summary Report.pdf	-
180	Alba_7042_202223_Newfoundland_Warranty Repair Report.pdf	-
181	CO7042 Newfoundland Olympus C 202223 Performance Test Report.pdf	-
182	1_Root Cause Analysis Process_25_04_2016.pdf	-
183	Alba_5269_Newfoundland_Hydro_Stephenville_Investigation_.pdf	-
184	Alba_5269_Newfoundland_Hydro_Stephenville_Investigation_29_03_16 .pdf	-
185	Alba_5593_ Nefoundland Hydro_202204 Commissioning_27_03_2017.pdf	-
186	Alba_6494_NewfoundlandHydro_202204 Borescope_Report_03_12_2018.pdf	-
187	Alba_6539_202204_Newfoundland Hydro_Bulk Strip Report_03_01_2019.pdf	-
188	Alba_6539_202204_Newfoundland Hydro_Final Summary Report.pdf	-
189	Alba_6539_202204_NewfoundlandHydro_ Detail Strip Inspection Report.pdf	-
190	Alba_6539_202204_NewfoundlandHydro_Receipt Inspection Report.pdf	-
191	Alba_6539_Newfoundland Hydro_202204_Installation & Commissioning_29_01_2020.pdf	-
192	Alba_6539_Newfoundland Hydro_202204_Installation & Commissioning_29_04_2020.pdf	-
193	Olympus SN 202204 images.pdf	-
194	4_Alba_5402_202205_Combustion chamber analysis - Issue 3.pdf	-
195	CO_5166_Report_ BP_Remove_ 202205_Install_202040 - Copy2.pdf	-
196	202205 Engine Test Data.pdf	-
197	4_Alba_5402_202205_Combustion chamber analysis - Issue 3.pdf	-
198	Alba_5903_202205_Newfoundland Hydro_Bulk Strip Inspection Report_16_11_2017.pdf	-
199	Alba_5903_202205_Newfoundland Hydro_Detail Strip Inspection Report_07_12_2017.pdf	-
200	Newfoundland 202223 Customer signed acceptance form..pdf	-
201	Newfoundland Hydro Olympus 202223 CO4117 Formatted.pdf	-
202	Newfoundland Hydro Olympus Vibration Data Report 24_9_14.pdf	-
203	Alba_6816_202223_Newfoundland Hydro_Final Summary Report.pdf	-
204	Alba_7042_202223_Newfoundland_Warranty Repair Report.pdf	-
205	CO7042 Newfoundland Olympus C 202223 Performance Test Report.pdf	-
206	202224 site recommendations.pdf	-
207	CO 4744 202224_202040.pdf	-
208	R.C.A report 202224.pdf	-
209	Section 1 - Executive Summary.pdf	-

Document Register Index #	File Name	Description
210	Section 10 - Engine Certificate of Conformity.pdf	-
211	Section 2 - 202224 - Receipt Inspection Report.pdf	-
212	Section 3 - 202224 - Bulk Strip Report.pdf	-
213	Section 4 - 202224 - Detail Strip Inspection Report.pdf	-
214	Section 5 - 1 Progress report - 202224 - 23-10-2015.pdf	-
215	Section 5 - 2 Progress report - 202224 - 30-10-2015.pdf	-
216	Section 5 - 3 Progress report - 202224 - 13-11-15.pdf	-
217	section 6 - Scrap Lists.pdf	-
218	Section 8 - Accessories Certificate of Conformity.pdf	-
219	Section 8 - Balance Certificates.pdf	-
220	Section 8 - Bearings Certificate of Conformity.pdf	-
221	Section 8 - Coating Certificate of Conformity.pdf	-
222	Section 8 - Engine Summary Test Certificate.pdf	-
223	Section 8 - Fuel Nozzles.pdf	-
224	Section 8 - Modifications.pdf	-
225	Section 9 - Engine Performance Test Results.pdf	-
226	Alba_5593_Nefoundland Hydro 202224 Inspection_24_03_2017.pdf	-
227	Alba_5840_202224_Newfoundland hydro test Report_15_11_2017.pdf	-
228	Alba_5840_Newfoundland Hydro_202224_Bulk Strip Report_21_09_2017.pdf	-
229	Alba_5840_NewfyHydro 202224 Olympus Receipt Inspection Report_24_08_17.pdf	-
229	13341S1.pdf	SSS Clutch Drawing
229	Clutch Manual.pdf	Clutch Manual
229	HWD & SVL GES 2020-2025 Report.pdf	HWD & SVL GES 2020-2025 Report
229	Olympus Manual	-
229	Olympus Overhauls and Repairs	-
229	133546845D3303-R0	HWD Stack Modifications
229	133546845D3304-R0	HWD Stack Modifications
229	133546845D3302-R0	HWD Stack Modifications
229	6 D3301-Rev 0	SVL Stack Modifications
229	7 D3302-Rev 0	SVL Stack Modifications
229	NL Hydro Life Cycle and Migration Report_Oct2021.pdf	2021 Report from ABB on Control System Life Cycle and Migration

Appendix C
Motor Control Center Quotations Received

Powering Business Worldwide

Detail Bill of Material

Project Name:	NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	**Negotiation No:**	DO560718X5K1
General Order No:		**Alternate No:**	0000

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E3A20624-MQty. :1,Description :,Accessories/Options :Primary Control Fuses150 VA Control Transformer (600V-120V) c/w Secondary FuseOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control WireUnit height 3X/18"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**12,665.19**	**12,665.19**

Catalog No E3A20624-M
Designation Unit 1B, FVNR size 3

Qty	List of Materials
1	Mark III, HMCP Combination Size 3 - FVNR Starter for 50 HP at 100A, 24"
1	Primary Control Fuses
1	150 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	Unit height 3X/18"
1	XT Nema starter series.

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: BDAHFD12-MQty. :1,Description :,Accessories/Options :Unit height 2X/12", 25Ka IC at 600vac. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**6,820.51**	**6,820.51**

Catalog No BDAHFD12-M
Designation LIC/RIC, dual feeder

Qty	List of Materials
1	Mark III, Circuit Breaker Dual Feeder Standard I.C. at 60/100 Amps, 12"
1	Unit height 2X/12", 25Ka IC at 600vac.

Powering Business Worldwide

Detail Bill of Material

Project Name:	NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	**Negotiation No:**	DO560718X5K1
General Order No:		**Alternate No:**	0000

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E3A20624-MQty.:1,Description :,Accessories/Options :Primary Control FusesRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control WireXTCE040 frame contactor, 50amp,125vdc energized from remote rectifier, NO POWER STABS, NO O/L.Unit height 3X/18" The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**12,530.60**	**12,530.60**

Catalog No E3A20624-M
Designation Unit 2B, 2p, 50amps contactor, 125VDC

Qty	List of Materials
1	Mark III, HMCP Combination Size 3 - FVNR Starter for 50 HP at 100A, 24"
1	Primary Control Fuses
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	XTCE040 frame contactor, 50amp,125vdc energized from remote rectifier, NO POWER STABS, NO O/L.
1	Unit height 3X/18"

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E1A20612-MQty.:1,Description :,Accessories/Options :Primary Control FusesOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 1.5X/9"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**8,797.02**	**8,797.02**

Catalog No E1A20612-M
Designation Unit 3A, FVNR size 1

Qty	List of Materials
1	Mark III, HMCP Combination Size 1 - FVNR Starter for 2 HP at 7A, 12"
1	Primary Control Fuses
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light

Powering Business Worldwide

Detail Bill of Material

Project Name:	NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	**Negotiation No:**	DO560718X5K1
General Order No:		**Alternate No:**	0000

Qty	List of Materials
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 1.5X/9"
1	XT Nema starter series.

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E1A20612-MQty. :1,Description :,Accessories/Options :Primary Control FusesOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 1.5X/9"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**8,797.02**	**8,797.02**

Catalog No E1A20612-M
Designation Unit 3B, FVNR size 1

Qty	List of Materials
1	Mark III, HMCP Combination Size 1 - FVNR Starter for 5 HP at 15A, 12"
1	Primary Control Fuses
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 1.5X/9"
1	XT Nema starter series.

EATON
Powering Business Worldwide

Detail Bill of Material

Project Name:	NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	**Negotiation No:**	DO560718X5K1
General Order No:		**Alternate No:**	0000

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E1A20612-MQty. :1,Description :,Accessories/Options :Primary Control FusesOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 1.5X/9"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**8,797.02**	**8,797.02**

Catalog No E1A20612-M
Designation Unit 3C, FVNR size 1

Qty	List of Materials
1	Mark III, HMCP Combination Size 1 - FVNR Starter for 10 HP at 30A, 12"
1	Primary Control Fuses
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 1.5X/9"
1	XT Nema starter series.

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E1A20612-MQty. :1,Description :,Accessories/Options :Primary Control FusesOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 1.5X/9"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**8,797.02**	**8,797.02**

Catalog No E1A20612-M
Designation Unit 3D, FVNR size 1

Detail Bill of Material

Project Name:	NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	**Negotiation No:**	DO560718X5K1
General Order No:		**Alternate No:**	0000

Qty	List of Materials
1	Mark III, HMCP Combination Size 1 - FVNR Starter for 10 HP at 30A, 12"
1	Primary Control Fuses
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 1.5X/9"
1	XT Nema starter series.

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VAC List of Material :Primary Wrapper Unit: E1A20612-MQty. :1,Description :,Accessories/Options :Primary Control FusesOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 1.5X/9"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**8,797.02**	**8,797.02**

Catalog No E1A20612-M
Designation Unit 3E, FVNR size 1

Qty	List of Materials
1	Mark III, HMCP Combination Size 1 - FVNR Starter for 10 HP at 30A, 12"
1	Primary Control Fuses
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 1.5X/9"
1	XT Nema starter series.

EATON
Powering Business Worldwide

Detail Bill of Material

Project Name:	NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	**Negotiation No:**	DO560718X5K1
General Order No:		**Alternate No:**	0000

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E1A20612-MQty. :1,Description :,Accessories/Options :Primary Control FusesOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 1.5X/9"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**8,797.02**	**8,797.02**

Catalog No E1A20612-M
Designation Unit 3F, FVNR size 1

Qty	List of Materials
1	Mark III, HMCP Combination Size 1 - FVNR Starter for 5 HP at 15A, 12"
1	Primary Control Fuses
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 1.5X/9"
1	XT Nema starter series.

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E1A20612-MQty. :1,Description :,Accessories/Options :Primary Control FusesOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 1.5X/9"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**8,797.02**	**8,797.02**

Catalog No E1A20612-M
Designation Unit 4A, FVNR size 1

Qty	List of Materials
1	Mark III, HMCP Combination Size 1 - FVNR Starter for 7.5 HP at 15A, 12"
1	Primary Control Fuses
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 1.5X/9"
1	XT Nema starter series.

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E1A20612-MQty. :1,Description :,Accessories/Options :Primary Control FusesOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 1.5X/9"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**8,797.02**	**8,797.02**

Catalog No E1A20612-M
Designation Unit 4B, FVNR size 1

Qty	List of Materials
1	Mark III, HMCP Combination Size 1 - FVNR Starter for 10 HP at 30A, 12"
1	Primary Control Fuses
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 1.5X/9"
1	XT Nema starter series.

Powering Business Worldwide

Detail Bill of Material

Project Name:	NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	**Negotiation No:**	DO560718X5K1
General Order No:		**Alternate No:**	0000

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E1A20612-MQty. :1,Description :,Accessories/Options :Primary Control FusesOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 1.5X/9"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**8,797.02**	**8,797.02**

Catalog No E1A20612-M
Designation Unit 4C, FVNR size 1

Qty	List of Materials
1	Mark III, HMCP Combination Size 1 - FVNR Starter for 10 HP at 30A, 12"
1	Primary Control Fuses
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 1.5X/9"
1	XT Nema starter series.

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E1A20612-MQty. :1,Description :,Accessories/Options :Primary Control FusesOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 1.5X/9"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**8,797.02**	**8,797.02**

Catalog No E1A20612-M
Designation Unit 4D, FVNR size 1

Detail Bill of Material

Powering Business Worldwide

Project Name:	NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	**Negotiation No:**	DO560718X5K1
General Order No:		**Alternate No:**	0000

Qty	List of Materials
1	Mark III, HMCP Combination Size 1 - FVNR Starter for 10 HP at 30A, 12"
1	Primary Control Fuses
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 1.5X/9"
1	XT Nema starter series.

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E1A20612-MQty. :1,Description :,Accessories/Options :Primary Control FusesOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 1.5X/9"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**8,797.02**	**8,797.02**

Catalog No E1A20612-M
Designation Unit 4E, FVNR size 1

Qty	List of Materials
1	Mark III, HMCP Combination Size 1 - FVNR Starter for 7.5 HP at 15A, 12"
1	Primary Control Fuses
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 1.5X/9"
1	XT Nema starter series.

Detail Bill of Material

Project Name:	NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	**Negotiation No:**	DO560718X5K1
General Order No:		**Alternate No:**	0000

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E1A20612-MQty. :1,Description :,Accessories/Options :Primary Control FusesOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 1.5X/9"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**8,797.02**	**8,797.02**

Catalog No E1A20612-M
Designation Unit 4F, FVNR size 1

Qty	List of Materials
1	Mark III, HMCP Combination Size 1 - FVNR Starter for 10 HP at 30A, 12"
1	Primary Control Fuses
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 1.5X/9"
1	XT Nema starter series.

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E3A20624-MQty. :1,Description :,Accessories/Options :Primary Control Fuses150 VA Control Transformer (600V-120V) c/w Secondary FuseOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control WireUnit height 3X/18"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**12,665.19**	**12,665.19**

Catalog No E3A20624-M
Designation Unit 4G, FVNR size 3

Detail Bill of Material

Project Name:	NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	**Negotiation No:**	DO560718X5K1
General Order No:		**Alternate No:**	0000

Qty	List of Materials
1	Mark III, HMCP Combination Size 3 - FVNR Starter for 50 HP at 100A, 24"
1	Primary Control Fuses
1	150 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	Unit height 3X/18"
1	XT Nema starter series.

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E2A20612-MQty. :1,Description :,Accessories/Options :Primary Control FusesOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 2X/12"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**10,003.99**	**10,003.99**

Catalog No E2A20612-M
Designation Unit 5A, FVNR size 2

Qty	List of Materials
1	Mark III, HMCP Combination Size 2 - FVNR Starter for 15 HP at 50A, 12"
1	Primary Control Fuses
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 2X/12"
1	XT Nema starter series.

EATON
Powering Business Worldwide

Detail Bill of Material

Project Name:	NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	**Negotiation No:**	DO560718X5K1
General Order No:		**Alternate No:**	0000

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E2A20612-MQty. :1,Description :,Accessories/Options :Primary Control FusesOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 2X/12"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**10,003.99**	**10,003.99**

Catalog No E2A20612-M
Designation Unit 5B, FVNR size 2

Qty	List of Materials
1	Mark III, HMCP Combination Size 2 - FVNR Starter for 20 HP at 50A, 12"
1	Primary Control Fuses
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 2X/12"
1	XT Nema starter series.

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E2A20612-MQty. :1,Description :,Accessories/Options :Primary Control FusesOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 2X/12"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**10,003.99**	**10,003.99**

Catalog No E2A20612-M
Designation Unit 5C, FVNR size 2

Detail Bill of Material

Project Name:	NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	**Negotiation No:**	DO560718X5K1
General Order No:		**Alternate No:**	0000

Qty	List of Materials
1	Mark III, HMCP Combination Size 2 - FVNR Starter for 20 HP at 50A, 12"
1	Primary Control Fuses
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 2X/12"
1	XT Nema starter series.

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E2A20612-MQty.:1,Description :,Accessories/Options :Primary Control FusesOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 2X/12"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**10,003.99**	**10,003.99**

Catalog No E2A20612-M
Designation Unit 5D, FVNR size 2

Qty	List of Materials
1	Mark III, HMCP Combination Size 2 - FVNR Starter for 15 HP at 50A, 12"
1	Primary Control Fuses
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 2X/12"
1	XT Nema starter series.

Detail Bill of Material

Project Name:	NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	**Negotiation No:**	DO560718X5K1
General Order No:		**Alternate No:**	0000

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E2A20612-MQty.:1,Description :,Accessories/Options :Primary Control FusesOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 2X/12"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**10,003.99**	**10,003.99**

Catalog No E2A20612-M
Designation Unit 5E, FVNR size 2

Qty	List of Materials
1	Mark III, HMCP Combination Size 2 - FVNR Starter for 20 HP at 50A, 12"
1	Primary Control Fuses
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 2X/12"
1	XT Nema starter series.

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E2A20612-MQty.:1,Description :,Accessories/Options :Primary Control FusesOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 2X/12"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**10,003.99**	**10,003.99**

Catalog No E2A20612-M
Designation Unit 5F, FVNR size 2

Powering Business Worldwide

Detail Bill of Material

Project Name:	NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	**Negotiation No:**	DO560718X5K1
General Order No:		**Alternate No:**	0000

Qty	List of Materials
1	Mark III, HMCP Combination Size 2 - FVNR Starter for 20 HP at 50A, 12"
1	Primary Control Fuses
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 2X/12"
1	XT Nema starter series.

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: BDAHFD12-MQty.:1,Description :,Accessories/Options :Unit height 2X/12", 25Ka IC at 600vac. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**6,820.51**	**6,820.51**

Catalog No BDAHFD12-M
Designation L6A/R6A, dual feeder

Qty	List of Materials
1	Mark III, Circuit Breaker Dual Feeder Standard I.C. at 50/70 Amps, 12"
1	Unit height 2X/12", 25Ka IC at 600vac.

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E4A20624-MQty.:1,Description :,Accessories/Options :Primary Control FusesRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire200 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 3X/18", FVC size 4 contactor, 100Kw load, NO O/L.XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**17,368.74**	**17,368.74**

Catalog No E4A20624-M
Designation Unit 6B, FVC size 4, no O/L

Detail Bill of Material

Project Name:	NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	**Negotiation No:**	DO560718X5K1
General Order No:		**Alternate No:**	0000

Qty	List of Materials
1	Mark III, HMCP Combination Size 4 - FVNR Starter for 100 HP at 150A, 24"
1	Primary Control Fuses
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	200 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 3X/18", FVC size 4 contactor, 100Kw load, NO O/L.
1	XT Nema starter series.

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E1A20612-MQty. :1,Description :,Accessories/Options :Primary Control FusesOverload Relay Heater/Heater PackRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 1.5X/9"XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**8,797.02**	**8,797.02**

Catalog No E1A20612-M
Designation Unit 6C, FVNR size 1

Qty	List of Materials
1	Mark III, HMCP Combination Size 1 - FVNR Starter for 7.5 HP at 15A, 12"
1	Primary Control Fuses
1	Overload Relay Heater/Heater Pack
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 1.5X/9"
1	XT Nema starter series.

Powering Business Worldwide

Detail Bill of Material

Project Name:	NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	**Negotiation No:**	DO560718X5K1
General Order No:		**Alternate No:**	0000

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E2A20612-MQty.:1,Description :,Accessories/Options :Primary Control FusesRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 2X/12", FVC size 2 contactor, 25Kw load, NO O/L.XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**9,766.99**	**9,766.99**

Catalog No E2A20612-M
Designation Unit 6D, FVC size 2, no O/L

Qty	List of Materials
1	Mark III, HMCP Combination Size 2 - FVNR Starter for 25 HP at 50A, 12"
1	Primary Control Fuses
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 2X/12", FVC size 2 contactor, 25Kw load, NO O/L.
1	XT Nema starter series.

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E2A20612-MQty.:1,Description :,Accessories/Options :Primary Control FusesRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 2X/12", FVC size 2 contactor, 33Kw load, NO O/L.XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**9,766.99**	**9,766.99**

Catalog No E2A20612-M
Designation Unit 6E, FVC size 2, no O/L

Qty	List of Materials
1	Mark III, HMCP Combination Size 2 - FVNR Starter for 25 HP at 50A, 12"
1	Primary Control Fuses
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch

Detail Bill of Material

Project Name:	NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	**Negotiation No:**	DO560718X5K1
General Order No:		**Alternate No:**	0000

Qty	List of Materials
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 2X/12", FVC size 2 contactor, 33Kw load, NO O/L.
1	XT Nema starter series.

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	MCC Aftermarket	QTY: 1 MCC General Description: Cutler Hammer Mark III MCC unit at 600VACList of Material :Primary Wrapper Unit: E2A20612-MQty.:1,Description :,Accessories/Options :Primary Control FusesRed 'Run' LightGreen 'Stopped' LightHAND-OFF-AUTO' Selector Switch2NO-2NC Starter Aux ContactsPull-apart Type Terminal Blocks (Standard)Wiring Diagram on Inside Starter Unit DoorType #14 Gauge Control WireWiremarkers - Sleeve Type on all Control Wire100 VA Control Transformer (600V-120V) c/w Secondary FuseUnit height 2X/12", FVC size 2 contactor, 25Kw load, NO O/L.XT Nema starter series. The Accessories/Options you have chosen may increase the height/size of the selected MCC Aftermarket Wrapper. Confirmation of unit height/size will be required with the Plant.	**9,766.99**	**9,766.99**

Catalog No E2A20612-M
Designation Unit 6F, FVC size 2, no O/L

Qty	List of Materials
1	Mark III, HMCP Combination Size 2 - FVNR Starter for 25 HP at 50A, 12"
1	Primary Control Fuses
1	Red 'Run' Light
1	Green 'Stopped' Light
1	HAND-OFF-AUTO' Selector Switch
1	2NO-2NC Starter Aux Contacts
1	Pull-apart Type Terminal Blocks (Standard)
1	Wiring Diagram on Inside Starter Unit Door
1	Type #14 Gauge Control Wire
1	Wiremarkers - Sleeve Type on all Control Wire
1	100 VA Control Transformer (600V-120V) c/w Secondary Fuse
1	Unit height 2X/12", FVC size 2 contactor, 25Kw load, NO O/L.
1	XT Nema starter series.

Eaton Selling Policy 25-000C applies.

If Eaton and the buyer entity listed on this purchase order have a separate executed written agreement for the products/services herein, then that agreement applies. Otherwise, Eaton's Selling Policy 25000 (https://www.eaton.com/ca/en-gb/support/terms-conditions.html) controls and supersedes all prior correspondence or communications between Eaton and the buyer, and any additional or different terms proposed by the buyer are rejected.

Seller shall not be responsible for any failure to perform, or delay in performance of, its obligations resulting from the COVID-19 pandemic or any future epidemic, and Buyer shall not be entitled to any damages resulting thereof.

Quoted lead times are normally based on our manufacturing plant capacity and loading. Our current lead times are impacted due to global supply chain disruptions and logistics challenges. We will provide lead times information within 3-4 weeks of receipt of order and actual lead times will be subject to availability of materials and plant loading at the time of manufacturing release.

Powering Business Worldwide

Detail Bill of Material

Project Name:	NL Hydro Mark III, 817853, 125VDC	**Negotiation No:**	DO560718X5K2
General Order No:		**Alternate No:**	0000

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	Motor Control Centers	60 Hz, Class 1B wiring, 200V 3-Phase Service, 42,000 Bracing, 25 Short Circuit Rating, Top Incoming, EEMAC 1A Gasketed 21" Front Mt Only enclosure, 600A Copper Main Horizontal Bus, No Neutral, Main Lugs. Used X-Space: 86, Blank X-Space: 10, Future X-Space: 0, MCC Lead Time Code: U.	**173,291.52**	**173,291.52**

Qty	List of Materials
2	XTCE040 contactor, 125vdc coil, control voltage 125vdc. Refer to DWG B1-373-E-019, unit B1B/B1C, no cpt.
1	SERVICE VOLTAGE, 125VDC, HFDDC3175L breaker, 7.5hp motor load.
2	SERVICE VOLTAGE, 125VDC, HFDDC3175L breaker, 6hp motor load.
2	STARTING RESISTOR , TECHNICAL DATA AND MANUFACTURER MODEL TO BE CONFIRMED BY THE CUSTOMER
2	XTCE300 contactor, Qty of 3, 125vdc coil, control voltage 125vdc. Refer to DWG B1-373-E-020, units B2B & B3B, no cpt.
2	SERVICE VOLTAGE, 125VDC, HKDDC3400L breaker, 20hp motor load.
2	SERVICE VOLTAGE, 125VDC, HFDDC3015L breaker, 1hp motor load.
1	XTCE150 contactor, Qty of 2, 125vdc coil, control voltage 125vdc. Refer to DWG B1-373-E-021, unit B4C, no cpt.
7	Red On LED pilot light
3	STARTING RESISTOR DATA AND MANUFACTURER MODEL TO BE CONFIRMED BY THE CUSTOMER
1	Main Lugs (#4-350 Kcmil, 2/ph, in 2X space factor)
1	NOT WIRED
2	XTCE150 contactor, Qte of (2), 125vdc coil, control voltage 125vdc. Refer to DWG B1-373-E-019, unit B2A/B3A, no cpt.
2	SERVICE VOLTAGE, 125VDC, HFDDC2050L breaker.
2	FVNR Starter Size 1 [TM Ckt Brk]
3	FVNR Starter Size 4 [HMCP]
2	FVNR Starter Size 6 [HMCP]
1	HFDCompact Bkr (50A trip)
1	HFDTwin Bkr (30A /60A trip)
10	Size 1-4 Starter - Normally Open
4	Size 5-6 Starter - Normally Open
4	Size 5-6 Starter - Normally Closed
10	Size 1-4 Starter - Normally Closed
2	Primary Control Fuse
7	3 Pos. Sel. Sw. (Hand-Off-Auto)
7	Green Off
7	Terminal Block - Pull Apart (7 point)
7	Bi-Metalic Overload Relay (Standard) c/w Heater Packs
7	Wiring Diagram on Door
7	PVC Sleeve Type Wiretags
7	#14awg, TEW Control Wire
9	Standard Trip
1	1 Unit PB (Emerg)
7	1NO-1NC Aux Contact
27	Additional X-Space
1	PL1 Panelboard 225A 120/240V 1PH 3W 24 CCT
8	Pnlbd Bkr, BAB 2 Pole 15A bkr
1	20 in. blank relay structure, 21" deep (Mounting Plate is 2.7" narrower than Structure Width)
5	12" Door
8	Structure Floor Leveling Channel Sills

Powering Business Worldwide

Detail Bill of Material

Project Name:	NL Hydro Mark III, 817853, 125VDC	**Negotiation No:**	DO560718X5K2
General Order No:		**Alternate No:**	0000

Qty	List of Materials
2	Additional Charges for Width-32'
3	Standard 20" Structure Width
7	600A Vertical Bus (Tin-plated cu)
8	Tin Plated Ground Bus
8	300A Horiz. Cu Gnd Bus, 1/4" x 1" Bar
8	42KA Bus Bracing
8	Tin Plated horizontal bus
1	Control Voltage Source : Phase to Neutral
3	Additional Charges for Width-24'
1	Service Voltage : 200
8	600A Copper Frnt Mtd 21" EEMAC 1A Gasketed
1	SERVICE & CONTROL VOLTAGE at 125VDC
1	SPECIAL CSA INSPECTION
1	Sections 5F and 6F are 40" wide.
1	Timing relays, and other controls not included in the DC starters and located into the DCS cabinet.
1	Resistor technical data, manufacturer and model # to be confirmed later by the customer and it is included in our bill of material.

Eaton Selling Policy 25-000C applies.

If Eaton and the buyer entity listed on this purchase order have a separate executed written agreement for the products/services herein, then that agreement applies. Otherwise, Eaton's Selling Policy 25000 (https://www.eaton.com/ca/en-gb/support/terms-conditions.html) controls and supersedes all prior correspondence or communications between Eaton and the buyer, and any additional or different terms proposed by the buyer are rejected.

Seller shall not be responsible for any failure to perform, or delay in performance of, its obligations resulting from the COVID-19 pandemic or any future epidemic, and Buyer shall not be entitled to any damages resulting thereof.

Quoted lead times are normally based on our manufacturing plant capacity and loading. Our current lead times are impacted due to global supply chain disruptions and logistics challenges. We will provide lead times information within 3-4 weeks of receipt of order and actual lead times will be subject to availability of materials and plant loading at the time of manufacturing release.

MCC General Information

MCC General Information

Wiring Diagram Type	Eaton Standard
MCC Quantity	1
Standards	CSA
Special Codes	CSA
Service Voltage (3 Phase)	200
Frequency	60
System	3PH3W
Witness Testing	No

Enclosure Specifications

Total Structures	8
Type	EEMAC 1A Gasketed
Depth	21" Front Mt Only
Height	90"
Horizontal Wireways	9" High, Top & Bottom
Vertical Wireways	4"
Channel Sills	Yes
Special Exterior Paint	No
Intercell Barrier	No
Handrails	No
150 Watt Space Heaters	No
Master Terminal Block Location	None
IBC/CBC Seismic Qualified	No
ABS Certified	No
Bottom Plates	None
Space Heater Thermostat	No

Bus System Specifications

Main Bus Amps	600
Main Bus Bar Plating	Tin
Insulated Horiz. Bus	None
Vertical Bus Amps	See Structure Schedule
Vertical Bus Material	Tin-Plated Copper
Bus Bracing	42
Ground Bus Location	Top
Ground Bus Lug Size	1-#6-350Kcmil
Ground Bus Lug Type	Screw
300A Vert. Gnd. Bus in Vert. Wireway	
Neutral	None
Horizontal Bus Temperature Rise	65 deg C
Bottom Vert. Bus Barrier	No
Vertical Ground Bus	No
Vertical Bus Barrier	Isolated, Red Polyester
Ground Bus	300

Incoming Line Termination

Cable Entry	Top
Splice Kit / Transition	None
MCC Type Match Up	**None**
MCC Type Match Up GO#	

Device: Main Lugs (#4-350 Kcmil, 2/ph, in 2X space factor)

MCC Starter Specifications

Wiring Class	1B
Control Voltage	120
Control Voltage Src	Phase to Neutral
Nameplate Size	1" X 2.5"
Nameplate Color	White / Black Letters
Pilot Dev. Model	10250T

Ind. Light Type	Full voltage

Structure Schedule

There are 8 structure(s).
Structure(s) 1, 2, 3, 4, 5, 6, 7 have a 600 A Vertical Bus.
Structure(s) 8 Have No Vertical Bus.
Total width of all sections is 204"
Height of all sections is 91"

Unit Modifications

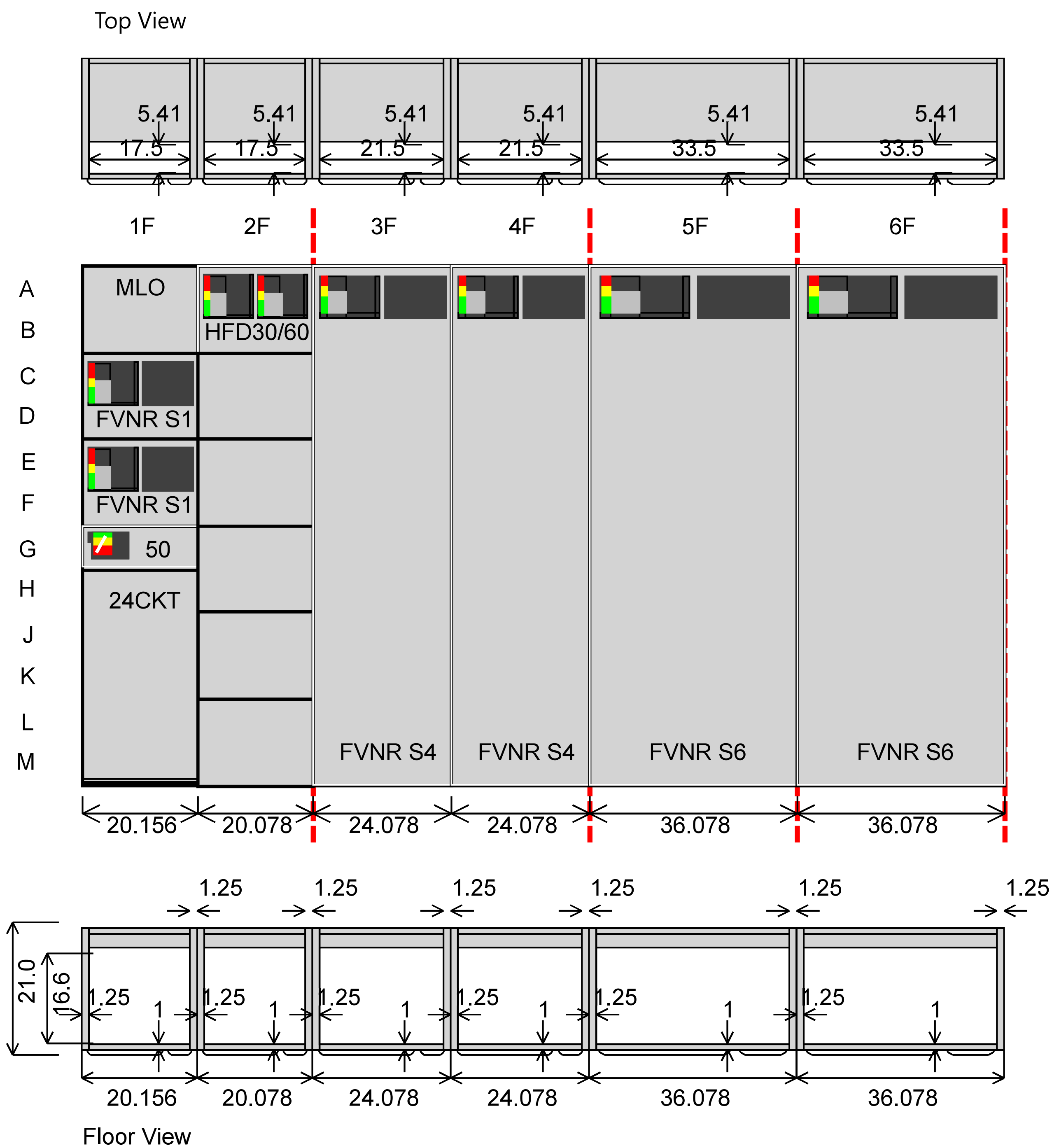
#14awg, TEW Control Wire
PVC Sleeve Type Wiretags
Wiring Diagram on Door
Bi-Metalic Overload Relay (Standard) c/w Heater Packs
Terminal Block - Pull Apart (7 point)
Primary Control Fuse

PREPARED BY: SERGE TREMBLAY	DATE: 2025-07-18	Eaton	Airdrie, Alberta
APPROVED BY:	DATE:	JOB NAME: NL Hydro Mark III, 817853, 125VDC	DESIGNATION:
VERSION: 1.0.3.4		TYPE: Freedom 2100 MCC	DRAWING TYPE: Customer Appr.
NEG-ALT Number: DO560718X5K2-0000	REVISION:	DWG SIZE: A	G.O.:
ITEM:	SHEET: 1 of 6		

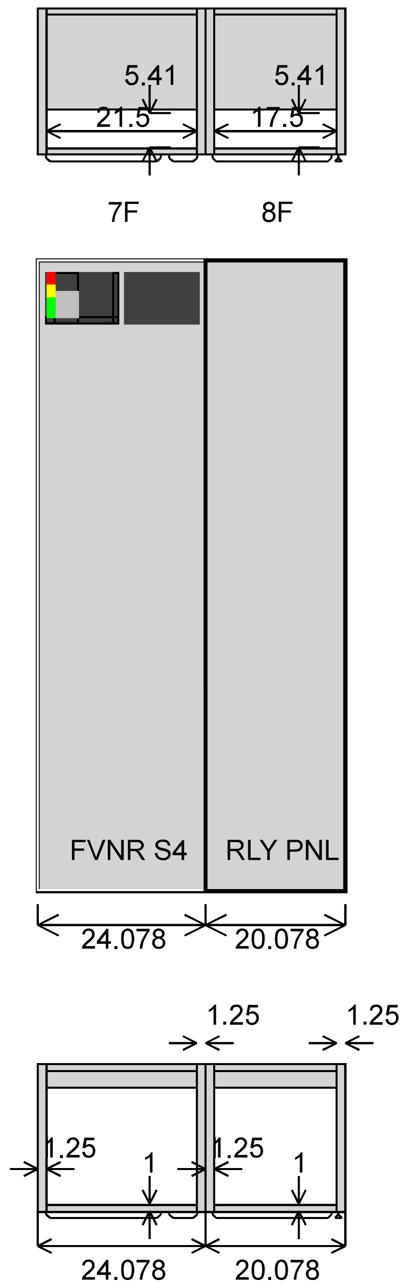
Notes/Special Instructions

SERVICE VOLTAGE, 125VDC, HFDDC3015L breaker, 1hp motor load. - unit 1D
XTCE040 contactor, 125vdc coil, control voltage 125vdc. Refer to DWG B1-373-E-019, unit B1B/B1C, no cpt. - unit 1D
Red On LED pilot light - unit 1D
SERVICE VOLTAGE, 125VDC, HFDDC3015L breaker, 1hp motor load. - unit 1F
XTCE040 contactor, 125vdc coil, control voltage 125vdc. Refer to DWG B1-373-E-019, unit B1B/B1C, no cpt. - unit 1F
Red On LED pilot light - unit 1F
NOT WIRED - unit 1M
SERVICE VOLTAGE, 125VDC, HFDDC2050L breaker. - unit 2B
SERVICE VOLTAGE, 125VDC, HFDDC3175L breaker, 6hp motor load. - unit 3M
XTCE150 contactor, Qte of (2), 125vdc coil, control voltage 125vdc. Refer to DWG B1-373-E-019, unit B2A/B3A, no cpt. - unit 3M
Red On LED pilot light - unit 3M
STARTING RESISTOR DATA AND MANUFACTURER MODEL TO BE CONFIRMED BY THE CUSTOMER - unit 3M
SERVICE VOLTAGE, 125VDC, HFDDC3175L breaker, 6hp motor load. - unit 4M
XTCE150 contactor, Qte of (2), 125vdc coil, control voltage 125vdc. Refer to DWG B1-373-E-019, unit B2A/B3A, no cpt. - unit 4M
Red On LED pilot light - unit 4M
STARTING RESISTOR DATA AND MANUFACTURER MODEL TO BE CONFIRMED BY THE CUSTOMER - unit 4M
SERVICE & CONTROL VOLTAGE at 125VDC
SPECIAL CSA INSPECTION
Sections 5F and 6F are 40" wide.
SERVICE VOLTAGE, 125VDC, HKDDC3400L breaker, 20hp motor load. - unit 5M
XTCE300 contactor, Qty of 3, 125vdc coil, control voltage 125vdc. Refer to DWG B1-373-E-020, units B2B & B3B, no cpt. - unit 5M
Red On LED pilot light - unit 5M
STARTING RESISTOR , TECHNICAL DATA AND MANUFACTURER MODEL TO BE CONFIRMED BY THE CUSTOMER - unit 5M
SERVICE VOLTAGE, 125VDC, HFDDC3175L breaker, 7.5hp motor load. - unit 7M
XTCE150 contactor, Qty of 2, 125vdc coil, control voltage 125vdc. Refer to DWG B1-373-E-021, unit B4C, no cpt. - unit 7M
Red On LED pilot light - unit 7M
STARTING RESISTOR DATA AND MANUFACTURER MODEL TO BE CONFIRMED BY THE CUSTOMER - unit 7M
SERVICE VOLTAGE, 125VDC, HKDDC3400L breaker, 20hp motor load. - unit 6M
XTCE300 contactor, Qty of 3, 125vdc coil, control voltage 125vdc. Refer to DWG B1-373-E-020, units B2B & B3B, no cpt. - unit 6M
Red On LED pilot light - unit 6M
STARTING RESISTOR , TECHNICAL DATA AND MANUFACTURER MODEL TO BE CONFIRMED BY THE CUSTOMER - unit 6M
Timing relays, and other controls not included in the DC starters and located into the DCS cabinet.
Resistor technical data, manufacturer and model # to be confirmed later by the customer and it is included in our bill of material.

The information on this document is created by Eaton Corporation. It is disclosed in confidence and it is only to be used for the purpose in which it is supplied.	PREPARED BY: SERGE TREMBLAY	DATE: 2025-07-18	**Eaton**	Airdrie, Alberta	
	APPROVED BY	DATE	JOB NAME: NL Hydro Mark III, 817853, 125VDC DESIGNATION		
	VERSION: 1.0.3.4		TYPE: Freedom 2100 MCC	DRAWING TYPE: Customer Appr.	
NEG-ALT Number: DO560718X5K2-0000	REVISION	DWG SIZE: A	G.O.	ITEM	SHEET: 2 of 6



The information on this document is created by Eaton Corporation. It is disclosed in confidence and it is only to be used for the purpose in which it is supplied.	PREPARED BY: SERGE TREMBLAY; DATE: 2025-07-18	**Eaton**	Airdrie, Alberta
	APPROVED BY; DATE	JOB NAME: NL Hydro Mark III, 817853, 125VDC; DESIGNATION	
	VERSION: 1.0.3.4	TYPE: Freedom 2100 MCC	DRAWING TYPE: Customer Appr.
NEG-ALT Number: DO560718X5K2-0000	REVISION; DWG SIZE: A	G.O.	ITEM; SHEET: 3 of 6



The information on this document is created by Eaton Corporation. It is disclosed in confidence and it is only to be used for the purpose in which it is supplied.	PREPARED BY: SERGE TREMBLAY DATE: 2025-07-18	Eaton	Airdrie, Alberta	
	APPROVED BY DATE	JOB NAME: NL Hydro Mark III, 817853, 125VDC DESIGNATION		
	VERSION: 1.0.3.4	TYPE: Freedom 2100 MCC	DRAWING TYPE: Customer Appr.	
NEG-ALT Number: DO560718X5K2-0000	REVISION / DWG SIZE: A	G.O.	ITEM	SHEET: 4 of 6

Unit	Nameplate	Description	Class	Starter Size HP/FLA Wire Diag.	Bkr/Sw Poles Trip/Clip	Unit Features
1B		Main Lugs (#4-350 Kcmil, 2/ph, in 2X space factor)		NONE		
1D	UNIT A GOVERNOR DRIVE	FVNR Starter Size 1 [TM Ckt Brk]	F206	1 1 NONE	Tm. Brk. 3P 15	2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Green Off 1 3 Pos. Sel. Sw. (Hand-Off-Auto) 1 1NO-1NC Aux Contact
1F	UNIT A GOVERNOR DRIVE	FVNR Starter Size 1 [TM Ckt Brk]	F206	1 1 NONE	Tm. Brk. 3P 15	2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Green Off 1 3 Pos. Sel. Sw. (Hand-Off-Auto) 1 1NO-1NC Aux Contact
1G		HFDCompact Bkr (50A trip)		5599A85.DWF	HFD 3P 50	
1M	LIGHTING PANEL A/C ONLY	PL1 Panelboard 225A 120/240V 1PH 3W 24 CCT		5A10397.DWF		8 Pnlbd Bkr, BAB 2 Pole 15A bkr
2BL		HFDTwin Bkr (30A /60A trip)		5599A85.DWF	HFD 3P 30	2 Standard Trip
2BR		HFDTwin Bkr (30A /60A trip)		5599A85.DWF	HFD 3P 60	2 Standard Trip
2D		12" Door				
2F		12" Door				
2H		12" Door				
2K		12" Door				
2M		12" Door				
3M	GENERATOR HYDRAULIC JACKING PUMP #1	FVNR Starter Size 4 [HMCP]	F206	4 40 NONE	HMCP 3P 150	2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 9 Additional X-Space 1 Green Off 1 3 Pos. Sel. Sw. (Hand-Off-Auto) 1 1NO-1NC Aux Contact
4M	GENERATOR HYDRAULIC JACKING PUMP #2	FVNR Starter Size 4 [HMCP]	F206	4 40 NONE	HMCP 3P 150	2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 9 Additional X-Space 1 Green Off 1 3 Pos. Sel. Sw. (Hand-Off-Auto) 1 1NO-1NC Aux Contact
5M		FVNR Starter Size 6 [HMCP]	F206	6 150 NONE	HMCP 3P 600	2 Size 5-6 Starter - Normally Open 2 Size 5-6 Starter - Normally Closed 1 Standard Trip 1 Green Off 1 3 Pos. Sel. Sw. (Hand-Off-Auto) 1 1NO-1NC Aux Contact
6M		FVNR Starter Size 6 [HMCP]	F206	6 150 NONE	HMCP 3P 600	2 Size 5-6 Starter - Normally Open 2 Size 5-6 Starter - Normally Closed 1 Standard Trip

PREPARED BY: SERGE TREMBLAY	DATE: 2025-07-18	Eaton	Airdrie, Alberta
APPROVED BY	DATE	JOB NAME: NL Hydro Mark III, 817853, 125VDC DESIGNATION	
VERSION: 1.0.3.4		TYPE: Freedom 2100 MCC	DRAWING TYPE: Customer Appr.
NEG-ALT Number: DO560718X5K2-0000	REVISION	DWG SIZE: A	G.O.
ITEM	SHEET: 5 of 6		

Unit	Nameplate	Description	Class	Starter Size HP/FLA Wire Diag.	Bkr/Sw Poles Trip/Clip	Unit Features
						1 Green Off 1 3 Pos. Sel. Sw. (Hand-Off-Auto) 1 1NO-1NC Aux Contact
7M	AUXILIARY FUEL FORWARDING PUMP	FVNR Starter Size 4 [HMCP]	F206	4 40 NONE	HMCP 3P 150	2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 9 Additional X-Space 1 Green Off 1 3 Pos. Sel. Sw. (Hand-Off-Auto) 1 1NO-1NC Aux Contact 1 1 Unit PB (Emerg)
8M		20 in. blank relay structure, 21" deep (Mounting Plate is 2.7" narrower than Structure Width)		NONE		

The information on this document is created by Eaton Corporation. It is disclosed in confidence and it is only to be used for the purpose in which it is supplied.

PREPARED BY: SERGE TREMBLAY	DATE: 2025-07-18	Eaton	Airdrie, Alberta
APPROVED BY	DATE	JOB NAME: NL Hydro Mark III, 817853, 125VDC DESIGNATION	
VERSION: 1.0.3.4		TYPE: Freedom 2100 MCC	DRAWING TYPE: Customer Appr.
NEG-ALT Number: DO560718X5K2-0000	REVISION	DWG SIZE: A	G.O.
ITEM	SHEET: 6 of 6		

Detail Bill of Material

Project Name:	NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	**Negotiation No:**	DO560718X5K1
General Order No:		**Alternate No:**	0001

Item No.	Qty	Product	Description	Unit Quote Price (CAD)	Extended Quote (CAD)
	1	Motor Control Centers	60 Hz, Class 1B wiring, 600V 3-Phase Service, 42,000 Bracing, 25 Short Circuit Rating, Top Incoming, EEMAC 1A Gasketed 21" Front Mt Only enclosure, 800A Copper Main Horizontal Bus, ANeutral. Used X-Space: 67, Blank X-Space: 5, Future X-Space: 0, MCC Lead Time Code: U.	**136,712.35**	**136,712.35**

Qty	List of Materials
25	Red Run
1	XTCE040 frame contactor, 50amp,125vdc energized from remote rectifier, NO POWER STABS, NO O/L.
1	Remote 125vdc source by customer
13	FVNR Compact Starter Sz 1 [HMCP]
6	FVNR Starter Size 2 [HMCP]
2	FVNR Starter Size 3 [HMCP]
3	FVC Contactor Size 2 [TM Ckt Brk]
1	FVC Contactor Size 3 [TM Ckt Brk]
1	FVC Contactor Size 4 [TM Ckt Brk]
1	HFDTwin Bkr (60A /100A trip)
1	HFDTwin Bkr (50A /70A trip)
3	Size 3, STARTER-150VA Typical, w/extra 50VA
13	Size 1, STARTER-100VA Typical, w/extra 50VA
52	Size 1-4 Starter - Normally Open
52	Size 1-4 Starter - Normally Closed
13	Red Stop
26	Primary Control Fuse
9	Size 2, STARTER-100VA Typical, w/extra 50VA
21	Bi-Metalic Overload Relay (Standard) c/w Heater Packs
13	Terminal Block - Pull Apart (7 point)
26	PVC Sleeve Type Wiretags
26	#14awg, TEW Control Wire
26	3 Pos. Sel. Sw. (Hand-Off-Auto)
13	Green Stop
30	Standard Trip
26	Wiring Diagram on Door
1	45 Kva 3 ph, 575V / 120-208V Xfmr, 60A Pri., 150A Sec. Bkr.
2	PL1 Panelboard 225A 120/208V 3PH 4W 24 CCT
4	Pnlbd Bkr, BAB 2 Pole 20A bkr
1	Pnlbd Bkr, BAB 2 Pole 15A bkr
13	Pnlbd Bkr, BAB 1 Pole 15A bkr
1	Pnlbd Bkr, BAB 1 Pole 20A bkr
1	24 in. blank relay panel (Mounting Plate is 2.7" narrower than Structure Width)
3	6" Door
1	12" Door
6	Tin Plated Ground Bus
6	42KA Bus Bracing
6	300A Horiz. Cu Gnd Bus, 1/4" x 1" Bar
1	18" Top Hat w/Main Lugs (Screw Type, #2 - 600 MCM, 2/ph)
6	600A Vertical Bus (Tin-plated cu)
6	Standard 20" Structure Width
6	Structure Floor Leveling Channel Sills
6	600A Copper Full Length Neutral Bus
6	Tin Plated horizontal bus
6	800A Copper Fmt Mtd 21" EEMAC 1A Gasketed

Eaton Selling Policy 25-000C applies.

EATON
Powering Business Worldwide

Detail Bill of Material

Project Name:	NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	**Negotiation No:**	DO560718X5K1
General Order No:		**Alternate No:**	0001

If Eaton and the buyer entity listed on this purchase order have a separate executed written agreement for the products/services herein, then that agreement applies. Otherwise, Eaton's Selling Policy 25000 (https://www.eaton.com/ca/en-gb/support/terms-conditions.html) controls and supersedes all prior correspondence or communications between Eaton and the buyer, and any additional or different terms proposed by the buyer are rejected.

Seller shall not be responsible for any failure to perform, or delay in performance of, its obligations resulting from the COVID-19 pandemic or any future epidemic, and Buyer shall not be entitled to any damages resulting thereof.

Quoted lead times are normally based on our manufacturing plant capacity and loading. Our current lead times are impacted due to global supply chain disruptions and logistics challenges. We will provide lead times information within 3-4 weeks of receipt of order and actual lead times will be subject to availability of materials and plant loading at the time of manufacturing release.

MCC General Information

MCC General Information

Wiring Diagram Type	Eaton Standard
MCC Quantity	1
Standards	CSA
Special Codes	CSA
Service Voltage (3 Phase)	600
Frequency	60
System	3PH4W
Witness Testing	No

Enclosure Specifications

Total Structures	6
Type	EEMAC 1A Gasketed
Depth	21" Front Mt Only
Height	90"
Horizontal Wireways	9" High, Top & Bottom
Vertical Wireways	4"
Channel Sills	Yes
Special Exterior Paint	No
Intercell Barrier	No
Handrails	No
150 Watt Space Heaters	No
Master Terminal Block Location	None
IBC/CBC Seismic Qualified	No
ABS Certified	No
Bottom Plates	None
Space Heater Thermostat	No

Bus System Specifications

Main Bus Amps	800
Main Bus Bar Plating	Tin
Insulated Horiz. Bus	None
Vertical Bus Amps	See Structure Schedule
Vertical Bus Material	Tin-Plated Copper
Bus Bracing	42
Ground Bus Location	Top
Ground Bus Lug Size	1-#6-350Kcmil
Ground Bus Lug Type	Screw
300A Vert. Gnd. Bus in Vert. Wireway	
Neutral	600
Neutral Bus Lug Location	Incoming Line
Neutral Bus Lug Size	1-#6-350Kcmil
Neutral Bus Lug Type	Screw
Horizontal Bus Temperature Rise	65 deg C
Bottom Vert. Bus Barrier	No
Vertical Ground Bus	No
Vertical Bus Barrier	Isolated, Red Polyester
Ground Bus	300

Incoming Line Termination

Cable Entry	Top
Splice Kit / Transition	None
MCC Type Match Up	**None**
MCC Type Match Up GO#	
Device: *None*	

MCC Starter Specifications

Wiring Class	1B
Control Voltage	120
Control Voltage Src	Ind CPT

Nameplate Size	1" X 2.5"
Nameplate Color	White / Black Letters
Pilot Dev. Model	10250T
Ind. Light Type	Full voltage

Structure Schedule

There are 6 structure(s).
All structures have a 600 A vertical bus.
Total width of all sections is 124"
Height of all sections is 91"

Unit Modifications

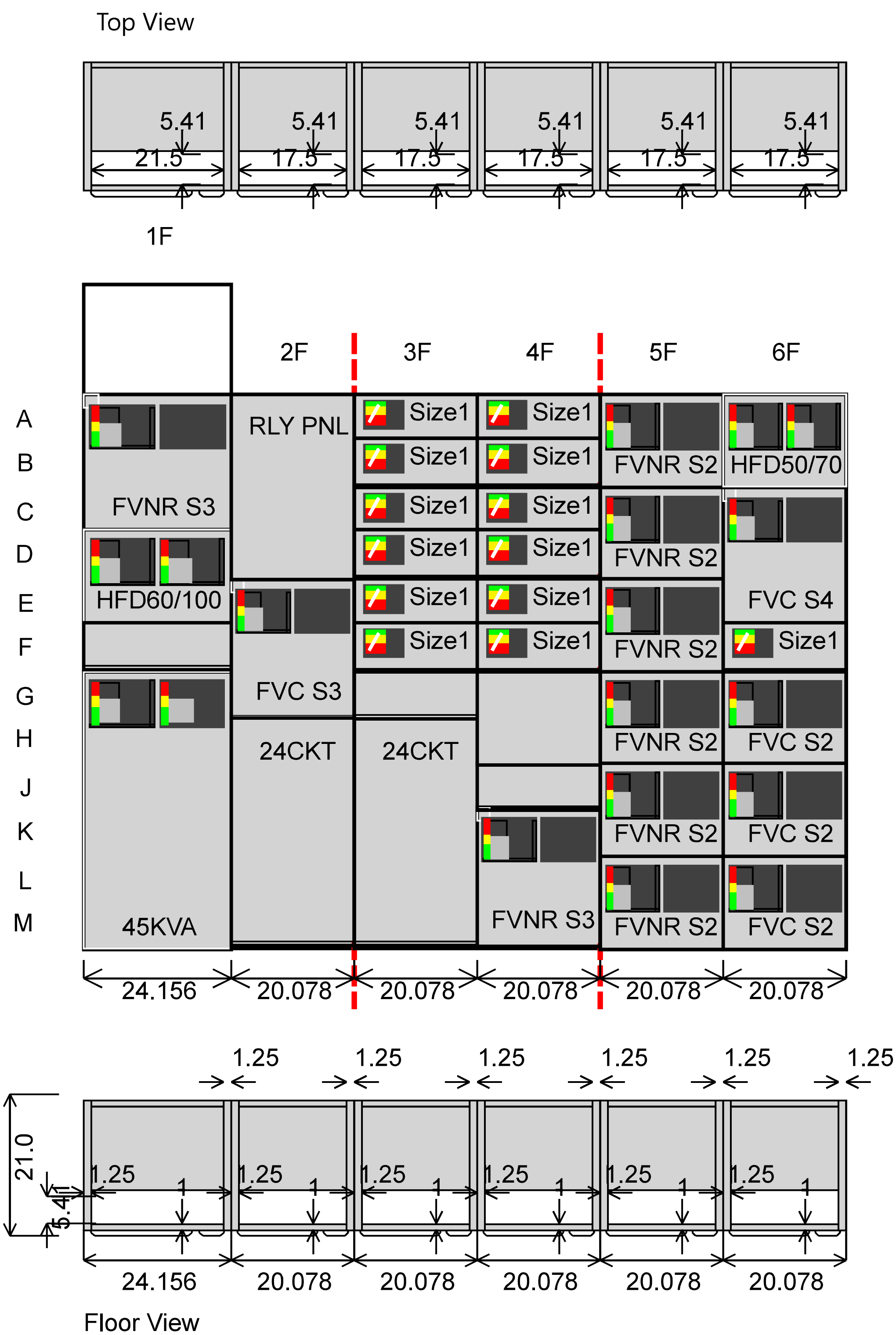
#14awg, TEW Control Wire
PVC Sleeve Type Wiretags
Wiring Diagram on Door
Bi-Metalic Overload Relay (Standard) c/w Heater Packs
Primary Control Fuse
Terminal Block - Pull Apart (7 point)

PREPARED BY: SERGE TREMBLAY	DATE: 2025-07-18	Eaton	Airdrie, Alberta
APPROVED BY	DATE	JOB NAME: NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	DESIGNATION
VERSION: 1.0.3.4		TYPE: Freedom 2100 MCC	DRAWING TYPE: Customer Appr.
NEG-ALT Number: DO560718X5K1-0001	REVISION	DWG SIZE: A	G.O.
ITEM	SHEET: 1 of 7		

Notes/Special Instructions

Red Run - unit 1C
XTCE040 frame contactor, 50amp,125vdc energized from remote rectifier, NO POWER STABS, NO O/L. - unit 2G
Remote 125vdc source by customer - unit 2G
Red Run - unit 3A
Red Run - unit 3B
Red Run - unit 3C
Red Run - unit 3D
Red Run - unit 3E
Red Run - unit 3F
Red Run - unit 4M
Red Run - unit 4A
Red Run - unit 4B
Red Run - unit 4C
Red Run - unit 4D
Red Run - unit 4E
Red Run - unit 4F
Red Run - unit 5B
Red Run - unit 5D
Red Run - unit 5F
Red Run - unit 5H
Red Run - unit 5K
Red Run - unit 5M
Red Run - unit 6E
Red Run - unit 6F
Red Run - unit 6H
Red Run - unit 6K
Red Run - unit 6M

PREPARED BY: SERGE TREMBLAY	DATE: 2025-07-18	Eaton	Airdrie, Alberta
APPROVED BY	DATE	JOB NAME: NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	DESIGNATION
VERSION: 1.0.3.4		TYPE: Freedom 2100 MCC	DRAWING TYPE: Customer Appr.
NEG-ALT Number: DO560718X5K1-0001	REVISION	DWG SIZE: A	G.O.
ITEM	SHEET: 2 of 7		



The information on this document is created by Eaton Corporation. It is disclosed in confidence and it is only to be used for the purpose in which it is supplied.	PREPARED BY: SERGE TREMBLAY	DATE: 2025-07-18	Eaton	Airdrie, Alberta
	APPROVED BY	DATE	JOB NAME: NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)	DESIGNATION
	VERSION: 1.0.3.4		TYPE: Freedom 2100 MCC	DRAWING TYPE: Customer Appr.
NEG-ALT Number: DO560718X5K1-0001	REVISION	DWG SIZE: A	G.O. / ITEM	SHEET: 3 of 7

Unit	Nameplate	Description	Class	Starter Size HP/FLA Wire Diag.	Bkr/Sw Poles Trip/Clip	Unit Features
1C		FVNR Starter Size 3 [HMCP]	F206	3 50 NONE	HMCP 3P 100	1 Size 3, STARTER-150VA Typical, w/extra 50VA 2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Green Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto)
1EL		HFDTwin Bkr (60A /100A trip)		5599A85.DWF	HFD 3P 60	2 Standard Trip
1ER		HFDTwin Bkr (60A /100A trip)		5599A85.DWF	HFD 3P 100	2 Standard Trip
1F		6" Door				
1M		45 Kva 3 ph, 575V / 120-208V Xfmr, 60A Pri., 150A Sec. Bkr.		5A10398.DWF		
2D		24 in. blank relay panel (Mounting Plate is 2.7" narrower than Structure Width)		NONE		
2G		FVC Contactor Size 3 [TM Ckt Brk]	F208	3 45KW NONE	Tm. Brk. 3P 70	1 Size 3, STARTER-150VA Typical, w/extra 50VA 2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Green Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto)
2M	Panel 2C	PL1 Panelboard 225A 120/208V 3PH 4W 24 CCT		5A10398.DWF		13 Pnlbd Bkr, BAB 1 Pole 15A bkr 1 Pnlbd Bkr, BAB 1 Pole 20A bkr 1 Pnlbd Bkr, BAB 2 Pole 15A bkr 4 Pnlbd Bkr, BAB 2 Pole 20A bkr
3A		FVNR Compact Starter Sz 1 [HMCP]	F206	1 2 NONE	HMCPE 3P 7	1 Size 1, STARTER-100VA Typical, w/extra 50VA 2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Red Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto)
3B		FVNR Compact Starter Sz 1 [HMCP]	F206	1 5 NONE	HMCPE 3P 15	1 Size 1, STARTER-100VA Typical, w/extra 50VA 2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Red Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto)
3C		FVNR Compact Starter Sz 1 [HMCP]	F206	1 10 NONE	HMCPE 3P 30	1 Size 1, STARTER-100VA Typical, w/extra 50VA 2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Red Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto)
3D		FVNR Compact Starter Sz 1 [HMCP]	F206	1 10 NONE	HMCPE 3P 30	1 Size 1, STARTER-100VA Typical, w/extra 50VA 2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Red Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto)

The information on this document is created by Eaton Corporation. It is disclosed in confidence and it is only to be used for the purpose in which it is supplied.	PREPARED BY: SERGE TREMBLAY DATE: 2025-07-18	**Eaton**	Airdrie, Alberta
	APPROVED BY DATE	JOB NAME: NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3) DESIGNATION	
	VERSION: 1.0.3.4	TYPE: Freedom 2100 MCC	DRAWING TYPE: Customer Appr.
NEG-ALT Number: DO560718X5K1-0001	REVISION / DWG SIZE: A	G.O. / ITEM	SHEET: 4 of 7

Unit	Nameplate	Description	Class	Starter Size HP/FLA Wire Diag.	Bkr/Sw Poles Trip/Clip	Unit Features
3E		FVNR Compact Starter Sz 1 [HMCP]	F206	1 10 NONE	HMCPE 3P 30	1 Size 1, STARTER-100VA Typical, w/extra 50VA 2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Red Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto)
3F		FVNR Compact Starter Sz 1 [HMCP]	F206	1 5 NONE	HMCPE 3P 15	1 Size 1, STARTER-100VA Typical, w/extra 50VA 2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Red Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto)
3G		6" Door				
3M	Panel 3G	PL1 Panelboard 225A 120/208V 3PH 4W 24 CCT		5A10398.DWF		
4A		FVNR Compact Starter Sz 1 [HMCP]	F206	1 7.5 NONE	HMCPE 3P 15	1 Size 1, STARTER-100VA Typical, w/extra 50VA 2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Red Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto)
4B		FVNR Compact Starter Sz 1 [HMCP]	F206	1 10 NONE	HMCPE 3P 30	1 Size 1, STARTER-100VA Typical, w/extra 50VA 2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Red Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto)
4C		FVNR Compact Starter Sz 1 [HMCP]	F206	1 10 NONE	HMCPE 3P 30	1 Size 1, STARTER-100VA Typical, w/extra 50VA 2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Red Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto)
4D		FVNR Compact Starter Sz 1 [HMCP]	F206	1 10 NONE	HMCPE 3P 30	1 Size 1, STARTER-100VA Typical, w/extra 50VA 2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Red Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto)
4E		FVNR Compact Starter Sz 1 [HMCP]	F206	1 7.5 NONE	HMCPE 3P 15	1 Size 1, STARTER-100VA Typical, w/extra 50VA 2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Red Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto)
4F		FVNR Compact Starter Sz 1 [HMCP]	F206	1 10 NONE	HMCPE 3P 30	1 Size 1, STARTER-100VA Typical, w/extra 50VA 2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Red Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto)

PREPARED BY: SERGE TREMBLAY	DATE: 2025-07-18	Eaton	Airdrie, Alberta	
APPROVED BY	DATE	JOB NAME: NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3)		
		DESIGNATION		
VERSION: 1.0.3.4		TYPE: Freedom 2100 MCC	DRAWING TYPE: Customer Appr.	
NEG-ALT Number: DO560718X5K1-0001	REVISION	DWG SIZE: A	G.O.	ITEM
SHEET: 5 of 7				

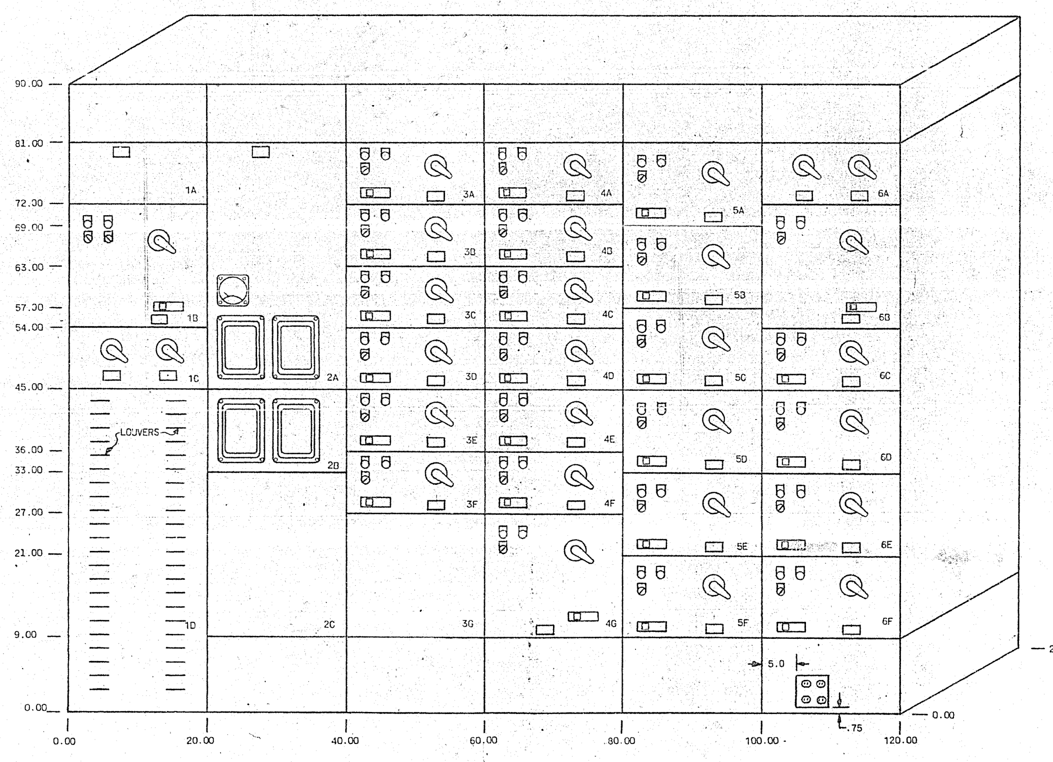
Unit	Nameplate	Description	Class	Starter Size HP/FLA Wire Diag.	Bkr/Sw Poles Trip/Clip	Unit Features
4H		12" Door				
4J		6" Door				
4M		FVNR Starter Size 3 [HMCP]	F206	3 50 NONE	HMCP 3P 100	1 Size 3, STARTER-150VA Typical, w/extra 50VA 2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Green Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto)
5B		FVNR Starter Size 2 [HMCP]	F206	2 15 NONE	HMCP 3P 30	2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Green Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto) 1 Size 2, STARTER-100VA Typical, w/extra 50VA
5D		FVNR Starter Size 2 [HMCP]	F206	2 20 NONE	HMCP 3P 50	2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Green Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto) 1 Size 2, STARTER-100VA Typical, w/extra 50VA
5F		FVNR Starter Size 2 [HMCP]	F206	2 20 NONE	HMCP 3P 50	2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Green Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto) 1 Size 2, STARTER-100VA Typical, w/extra 50VA
5H		FVNR Starter Size 2 [HMCP]	F206	2 15 NONE	HMCP 3P 30	2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Green Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto) 1 Size 2, STARTER-100VA Typical, w/extra 50VA
5K		FVNR Starter Size 2 [HMCP]	F206	2 20 NONE	HMCP 3P 50	2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Green Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto) 1 Size 2, STARTER-100VA Typical, w/extra 50VA
5M		FVNR Starter Size 2 [HMCP]	F206	2 20 NONE	HMCP 3P 50	2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Green Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto) 1 Size 2, STARTER-100VA Typical, w/extra 50VA
6BL		HFDTwin Bkr (50A /70A trip)		 5599A85.DWF	HFD 3P 50	2 Standard Trip
6BR		HFDTwin Bkr (50A /70A trip)		 5599A85.DWF	HFD 3P 70	2 Standard Trip
6E		FVC Contactor Size 4 [TM Ckt Brk]	F208	4 100KW NONE	Tm. Brk. 3P 150	2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip

Unit	Nameplate	Description	Class	Starter Size HP/FLA Wire Diag.	Bkr/Sw Poles Trip/Clip	Unit Features
						1 3 Pos. Sel. Sw. (Hand-Off-Auto) 1 Green Stop
6F		FVNR Compact Starter Sz 1 [HMCP]	F206	1 7.5 NONE	HMCPE 3P 15	1 Size 1, STARTER-100VA Typical, w/extra 50VA 2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Red Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto)
6H		FVC Contactor Size 2 [TM Ckt Brk]	F208	2 30KW NONE	Tm. Brk. 3P 50	2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Green Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto) 1 Size 2, STARTER-100VA Typical, w/extra 50VA
6K		FVC Contactor Size 2 [TM Ckt Brk]	F208	2 34KW NONE	Tm. Brk. 3P 50	2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Green Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto) 1 Size 2, STARTER-100VA Typical, w/extra 50VA
6M		FVC Contactor Size 2 [TM Ckt Brk]	F208	2 30KW NONE	Tm. Brk. 3P 50	2 Size 1-4 Starter - Normally Open 2 Size 1-4 Starter - Normally Closed 1 Standard Trip 1 Green Stop 1 3 Pos. Sel. Sw. (Hand-Off-Auto) 1 Size 2, STARTER-100VA Typical, w/extra 50VA

PREPARED BY: SERGE TREMBLAY	DATE: 2025-07-18	**Eaton**	Airdrie, Alberta
APPROVED BY:	DATE:	JOB NAME: NL Hydro, Mark III, 817852, 600v, 3ph, 3w (U2120704X5K3) DESIGNATION:	
VERSION: 1.0.3.4		TYPE: Freedom 2100 MCC	DRAWING TYPE: Customer Appr.
NEG-ALT Number: DO560718X5K1-0001	REVISION: / DWG SIZE: A	G.O.: / ITEM:	SHEET: 7 of 7

182009
1 of 2

LOCATION	DESCRIPTION	HP	3 POLE MCCB	CEMA SIZE	OL HEATER
1A	INCOMING 2 NO. 350 MCM PER PHASE	----	----	----	----
1B	MAIN LUBE OIL PUMP	50	100A	3	H1049
1CL	TRANSFORMER DISCONNECT BREAKER	----	60A	----	----
1CR	[illegible]	----	150A	----	----
1D	[illegible] FORMER	45KVA	----	----	----
2A	RELAYS PANEL	----	----	----	----
2B	PROTECTIVE RELAYING	----	----	----	----
2C	24-CIRCUIT PANEL 3 PHASE 4 WIRE	----	----	----	----
3A	TURBINE LUBE OIL HEAT EXCHANGER COOLING FAN NO. 1	5	15A	1	H1031
3B	TURBINE LUBE OIL HEAT EXCHANGER COOLING FAN NO. 1	5	15A	1	H1031
3C	MAIN FUEL FORWARDING PUMP	10	15A	1	H1037
3D	STAND-BY FUEL FORWARDING PUMP	10	15A	1	H1037
3E	STARTING AIR COMPRESSOR NO. 1	7-1/2	15A	1	H1035
3F	STARTING AIR COMPRESSOR NO. 2	7-1/2	15A	1	H1035
3G	12-CIRCUIT PANEL 3 PHASE 4 WIRE	----	----	----	----
4A	DEMISTER	2	7A	1	H1025
4B	MAIN LUBE VAPOR EVACUATOR	10	15A	1	H1037
4C	TURBINE A INLET FILTER BLOWER NO. 1	10	15A	1	H1037
4D	TURBINE A INLET FILTER BLOWER NO.2	10	15A	1	H1037
4E	TURBINE B INLET FILTER BLOWER NO. 1	10	15A	1	H1037
4F	TURBINE B INLET FILTER BLOWER NO. 2	10	15A	1	H1037
4G	STAND-BY LUBE PUMP	50	100A	3	H1049
5A	TURBINE GLYCOL PUMP	15	30A	2	H1040
5B	BATTERY ROOM HTR	3KW	30A	2	H1040
5C	UNIT A ENCLOSURE FAN NO. 1	[illegible]	30A	2	[illegible]
5D	UNIT A ENCLOSURE FAN NO. 2	[illegible]	30A	2	[illegible]
5E	UNIT B ENCLOSURE FAN NO. 1	[illegible]	30A	2	[illegible]
5F	UNIT B ENCLOSURE FAN NO. 2	[illegible]	30A	2	[illegible]
6AL	CUSTOMER USE C.B.-MAINT BLD FEED	----	150A	----	----
6AR	BATTERY CHARGER FEEDER BREAKER	----	70A	----	----
6B	FUEL OIL HEATERS	100KW	[illegible]	4	----
6C	SWITCHGEAR HEATERS	5KW	15A	1	----
6D	GENERATOR HEATERS	33KW	[illegible]	2	----
6E	TURBINE/GENERATOR LUBE OIL HEATER NO. 1	25KW	[illegible]	2	----
6F	TURBINE/GENERATOR LUBE OIL HEATER NO. 2	25KW	30A	2	----
L.END L.	GGA SUPPL FUEL PUMP	25HP	50A	2	FH54
L.END R.	GGB SUPPL FUEL PUMP	25HP	50A	2	FH54



DTR.		8 July 76
CKR.	MGP	8 July 76
SUPV.		
MET.		
MFG.		
ENGR.		8 July 76
ENGR.		
ENGR.		

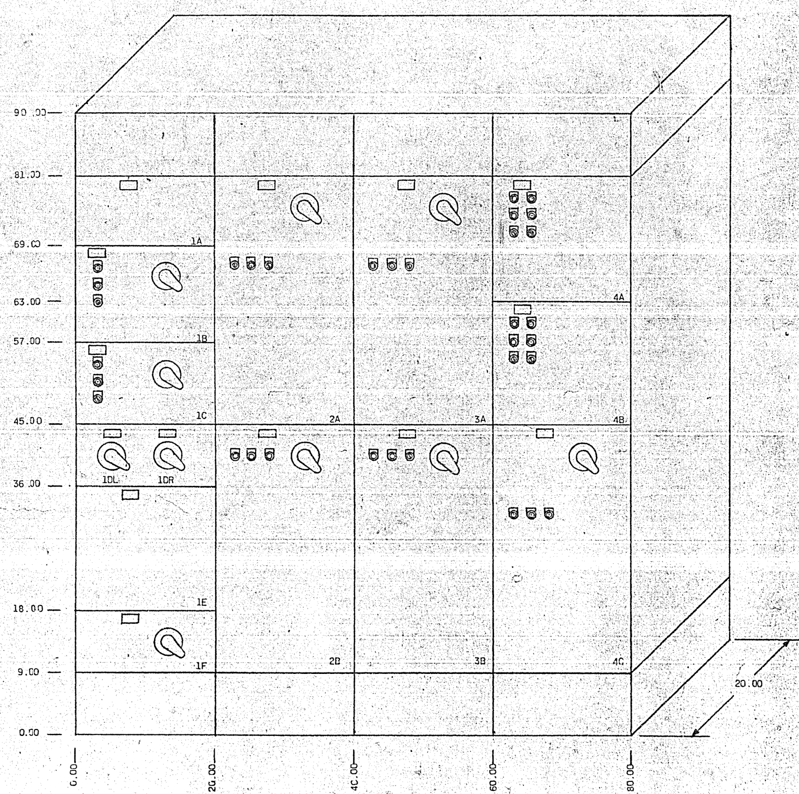
POWER SYSTEMS
CURTISS-WRIGHT CORP. WOOD-RIDGE, NEW JERSEY, U.S.A.

NEWFOUNDLAND & LABRADOR HYDRO

AC MCC LAYOUT

CODE IDENT. NO.	SIZE	
66640		182009
SCALE 1½"=1'-0"	UNIT WT.	SHEET 1 OF 2

182010
SHT. 1 OF 1



LOCATION	DESCRIPTION	HP	2 POLE MCCB	CEMA SIZE	ACCEL POINT	OL HEATER
1A	INCOMING CABLE & AMMETER SHUNT	---	-----	----	----	---
1B	UNIT A GOVERNOR DRIVE	0 .5	15A	1	1	H810J05ABA
1C	UNIT B GOVERNOR DRIVE & RELAY 45FX7	0 .5	15A	1	1	H810J05ABA
1DL	CONTROL POWER FEEDER	---		---	---	---
1DR	INVERTER FEEDER	---		---	---	---
1E	EMERGENCY LTG. PANEL	---	8 AT 15A	---	---	---
1F	EMERGENCY LTG. CONTRACTOR	---	50A	---	---	---
2A	GENERATOR HYDRAULIC JACKING PUMP NO. 1	6	70A	---	2	H810J12ABA
2B	EMERGENCY LUBE PUMP NO. 1	20	225	---	3	H810J24ABA
3A	GENERATOR HYDRAULIC JACKING PUMP NO. 2	6	70A	---	2	H810J12ABA
3B	EMERGENCY LUBE PUMP NO. 2	20	225	---	3	H810J24ABA
4A	END A SNOW DOORS	---	[illegible]	---	---	---
4B	END B SNOW DOORS	---		---	---	---
4C	AUX FUEL FORWARDING PUMP	7.5	90A	---	2	H810AJ14ABA

DTR.	[illegible]	30 AUG 76
CKR.	[illegible]	30 AUG 76
SUPV.		
MET.		
MFG.		
ENGR.	[illegible]	31 Aug 76
ENGR.		
ENGR.		

POWER SYSTEMS
CURTISS-WRIGHT CORP., WOOD-RIDGE, NEW JERSEY, U.S.A.

NEWFOUNDLAND & LABRADOR HYDRO
ASSEMBLY " B"
DC MCC LAYOUT

CODE IDENT. NO.	SIZE	
66640		182010
SCALE 1/2 : 1"	UNIT WT.	SHEET 1 OF 1

Appendix D
ABB 2021 Lifecycle Plan Listings for Parts and Service Support Status for Key Control System Components

D.1 Hardwoods ABB 2021 Lifecycle Plan Listing for Parts and Service Support Status for Key Control System Components

NODE	Part Description	Nomenclature Description	Quantity	Lifecycle Status	New Replacement	Upgrade Plan
All	Modular Power System III	MPSIII	1	Active	MPSIII or IV	Current - new installations will use MPSIV
CIU	Communication Loop Interface	SPNIS21	1	Active	SPNIS21	Current
CIU	Computer Ethernet Interface	SPIET800	1	Active	SPIET800	Current
3	Communication Loop Interface	INNIS01	1	Obsolete	SPNIS21	Both INNIS01 & INSEM01 would have to be upgraded at the
3	Sequence of Events Master	INSEM01	1	Obsolete	SPSEM11	time. No config change is required
3	Time Keeper Master	INTKM01	1	Limited	SPTKM01	1:1 replacement - no config change required
5	Communication Loop Interface	INNIS01	2	Obsolete	SPNIS21	Redundant set of INNIS01 & INNPM01 would have to be upgraded
5	Network Processing Module	INNPM01	2	Obsolete	SPNPM22	at the same time. No config change required
5	Multi-Function Processor	IMMFP02	4	Obsolete	BRC410	Each set of controllers must be changed - no config change required
5	Sequence of Events Time Sync	IMSET01	1	Limited	SPSET01	1:1 replacement - no config change required
5	Sequence of Events Dig Inputs	IMSED01	7	Limited	SPSED01	1:1 replacement - no config change required
5	Frequency Counter Slave	IMFCS01	8	Obsolete	SPTPS13FCS	1:1 replacement - NOTE: A config change is required
5	Turbine Speed Adapter Module	ETSI / TAS01	1	Obsolete	SPTPS13TSA	1:1 replacement - no config change required
5	Analog Input Slave	IMASI03	7	Obsolete	SPASI23	1:1 replacement - no config change required
5	Digital Input Slave	IMDSI02	6	Obsolete	SPDSI22	1:1 replacement - no config change required
5	Control Input/Output Slave	IMCIS02	2	Obsolete	SPCIS22	1:1 replacement - no config change required
5	Digital Output Slave	IMDSO04	7	Obsolete	SPDSO14	1:1 replacement - no config change required
I/O term.						
Behind console	Analog Inputs with IMASI03	NTAI06	7	Active	NTAI06	1:1 replacement available - no config change required
Behind console	Control I/O with IMCIS02	NTCS04	2	Active	NTCS04	1:1 replacement available - no config change required
Behind console	Digital Inputs with IMDSI02	NTDI01	7	Active	NTDI01	1.1 replacements available - no config change required
Behind console	Sequence of Events	NTST01	2	Active	NTST01	1:1 replacement available - no config change required
Behind console	Digital Inputs with IMSED01	NTDI01	9	Active	NTDI01	1:1 replacement available - no config change required
Behind console	Digital Outputs with IMDSO04	NRDO02	7	Active	NRDO02	1.1 replacements available - no config change required
Cabinet - back	Loop Comm with INNIS01	NTCL01	2	Active	NTCL01	1:1 replacement available - no config change required
Cabinet - front	Loop Comm with INNIS01	NTCL01	2	Active	NTCL01	1:1 replacement available - no config change required
Software						
	S+ Engineering	Composer 6.1		Obsolete	S+ Eng 2.3	upgrade required - new computers must use version 2.3
	S+ Operations	S+ Ops 2.1.2		Active	S+ Ops 3.3	supported - new installations must use version 3.3

D.2 Stephenville ABB 2021 Lifecycle Plan Listing for Parts and Service Support Status for Key Control System Components

NODE	Part Description	Nomenclature Description	Quantity	Lifecycle Status	New Replacement	Upgrade Plan
All	Modular Power System 1	MPSI	1	Obsolete	MPSIV	Upgrade is required
CIU	Communication Loop Interface	INNIS01	1	Obsolete	SPNIS21	Both INNIS01 & INICT01 would have to be upgraded at the same
CIU	Computer Ethernet Interface	INICT01	1	Obsolete	SPIET800	time when the operator console is upgraded.
5	Communication Loop Interface	INNIS01	2	Obsolete	SPNIS21	Redundant set of INNIS01 & INNPM01 would have to be upgraded
5	Network Processing Module	INNPM01	2	Obsolete	SPNPM22	at the same time. No config change required
5	Multi-Function Processor	IMMFP02	6	Obsolete	BRC410	Each set of controllers must be changed - no config change required
5	Sequence of Events Time Sync	IMSET01	1	Limited	SPSET01	1:1 replacement - no config change required
5	Sequence of Events Dig Inputs	IMSED01	8	Limited	SPSED01	1:1 replacement - no config change required
5	Frequency Counter Slave	IMFCS01	8	Obsolete	SPTPS13FCS	1:1 replacement - Note: A config change is required
5	Turbine Speed Adapter Module	ETSI / TAS01	1	Obsolete	SPTPS13TSA	1:1 replacement - no config change required
5	Analog Input Slave	IMFEC12	1	Obsolete	SPFEC12	1:1 replacement - no config change required
5	Analog Input Slave	IMASI03	7	Obsolete	SPASI23	1:1 replacement - no config change required
5	Digital Input Slave	IMDSI02	6	Obsolete	SPDSI22	1:1 replacement - no config change required
5	Control Input/Output Slave	IMCIS02	2	Obsolete	SPCIS22	1:1 replacement - no config change required
5	Digital Output Slave	IMDSO04	8	Obsolete	SPDSO14	1:1 replacement - no config change required
I/O Terminations						
cabinet	Analog Inputs with IMASI03	NTAI06	7	Active	NTAI06	1:1 replacement available - no config change required
cabinet	Control I/O with IMCIS02	NTCS04	2	Active	NTCS04	1:1 replacement available - no config change required
cabinet	Digital Inputs with IMDSI02	NTDI01	7	Active	NTDI01	1.1 replacements available - no config change required
cabinet	Sequence of Events	NTST01	2	Active	NTST01	1:1 replacement available - no config change required
cabinet	Digital Inputs with IMSED01	NTDI01	9	Active	NTDI01	1:1 replacement available - no config change required
cabinet	Digital Outputs with IMDSO04	NRDO02	7	Active	NRDO02	1.1 replacements available - no config change required
cabinet	Loop Comm with INNIS01	NTCL01	2	Active	NTCL01	1:1 replacement available - no config change required
cabinet	Loop Comm with INNIS01	NTCL01	2	Active	NTCL01	1:1 replacement available - no config change required
Software						
	S+ Engineering	Composer 6.1		Obsolete	S+ Eng 2.3	upgrade required - Composer 6.1 will not work on Win 10
	Process Control View	PCV 5.2update 4		Obsolete	S+ Ops 3.3	upgrade required - PCV will not work on Windows 10

Attachment 2

CT Replacement Study Cost Estimate Report

newfoundland labrador hydro

HATCH

Newfoundland and Labrador Hydro
Hardwoods and Stephenville LECA Study

CT Replacement Study Cost Estimate Report

H375814-0000-100-066-0002

PROVINCE OF NEWFOUNDLAND
PEG Newfoundland and Labrador PROFESSIONAL ENGINEERS AND GEOSCIENTISTS
PERMIT HOLDER
CLASS "A"
This Permit Allows
HATCH LTD.
06735
To practice Professional Engineering in Newfoundland and Labrador
Permit No. as issued by PEG-NL D0090
which is valid for the year 2026

LICENSED PROFESSIONAL ENGINEER
08879
G. D. COOPER
SIGNATURE
2026-04-29
DATE
NEWFOUNDLAND & LABRADOR

			Ghantous, Tia	DeYoung, Scot	
2026-04-27	1	Approved for Use (General Revision)	T. Ghantous	S. DeYoung	G. Cooper
2026-03-30	0	Approved for Use	T. Ghantous	S. DeYoung	G. Cooper
Date	**Rev.**	**Status**	**Prepared By**	**Checked By**	**Approved By**
HATCH					

IMPORTANT NOTICE TO READER

This report, including the assessment contained herein, has been prepared by Hatch Ltd. (“Hatch”) for the sole and exclusive use of Newfoundland and Labrador Hydro (the “Client”) for the purpose of assisting the management of the Client in making decisions with respect to the replacement of the Stephenville and Hardwood Power Stations (the “Assets”). Any use of or reliance upon this report by another person is done at their sole risk and Hatch does not accept any responsibility or liability in connection with that person’s use or reliance.

This report must not be used by the Client for any other purpose. Use or reliance upon this report or its contents by a third party is at such party’s sole and exclusive risk. Hatch makes no warranty or representation of fitness and disclaims any and all liability arising out of such use or reliance. The use of this report by the Client is subject to the terms of the relevant services agreement between Hatch and the Client.

This report is meant to be read as a whole, and sections should not be read or relied upon out of context. The report includes information provided by the Client and by certain other parties on behalf of the Client. Unless specifically stated otherwise, Hatch has not verified such information and does not accept any responsibility or liability in connection with such information.

This report contains the expression of the opinion of Hatch using its professional judgment and reasonable care, based upon information available at the time of preparation. The quality of the information, conclusions and estimates contained in this report is consistent with the intended level of accuracy as set out in this report, as well as the circumstances and constraints under which this report was prepared.

As this report is a part of a replacement cost study for the development of a Class 5 level estimate, all estimates and projections contained in this report are based on limited and incomplete data. Accordingly, while the work, results, estimates and projections in this report may be considered to be generally indicative of the nature and quality of the Project, they are not definitive. No representations or predictions are intended as to become the results of future work, and Hatch does not promise that the estimates and projections in this report will be sustained in future work.

Table of Contents

1. Introduction 1

2. Replacement Combustion Turbine Generator Options Review 2

2.1 Design and Performance Criteria for Replacement CTGs 2
2.2 Comparison of Aeroderivative vs. Industrial CTGs and Synchronous Condensing Considerations 3
2.3 CTG Options Summary 4
2.4 CTG Selection for Study Basis and CAPEX Development 6
2.5 CTG Performance Summary 6

3. Fuel Storage Review 7

3.1 Hardwoods Fuel Storage 7
3.2 Stephenville Fuel Storage 8

4. CTG Location Assessment and Layout Development 9

4.1 Hardwoods Replacement Concept 10
4.2 Stephenville Replacement Concept 12

5. Cost Estimate 13

5.1 Aeroderivative Gas Turbine (1 x 50 MW) Cost Estimate 14
5.2 Industrial Gas Turbine (2 x 25 MW) Cost Estimate 16
5.3 Additional Cost Estimate Considerations for Future Fuel Supply and Storage Options 17
5.3.1 Fuel Capacity Expansion 17
5.3.2 Biofuel Conversion 17
5.3.3 Conversion to Hydrogen Operation (Excluding Delivery and Storage Infrastructure) 18

6. Conclusions and Next Steps 18

List of Tables

Table 2-1: Aeroderivative Combustion Turbine Options 4
Table 2-2: Industrial Combustion Turbine Options 5
Table 2-3: GTPro Performance Summary 6
Table 3-1: Hardwoods Estimated Diesel Fuel Storage Durations (2,226,000 L storage capacity) 7
Table 3-2: Stephenville Estimated Diesel Fuel Storage Durations (1,431,000 L storage capacity) 8
Table 5-1: Aeroderivative Gas Turbine (1 x 50 MW) Cost Breakdown 15
Table 5-2: Industrial Gas Turbine (2 x25 MW) Cost Breakdown 16

List of Appendices

Appendix A: Plot Plan Sketches
- A.1: Hardwoods Generating Station, Aeroderivative Gas Turbine (1 x 50 MW)
- A.2: Hardwoods Generating Station, Industrial Gas Turbine (2 x 25 MW)
- A.3: Stephenville Generating Station, Aeroderivative Gas Turbine (1 x 50 MW)
- A.4: Stephenville Generating Station, Industrial Gas Turbine (2 x 25 MW)

Appendix B: Reference Drawings
Appendix C: Combustion Turbine Supplier Inquiries

Acronyms

AACE	Association for the Advancement of Cost Engineering
bbl	Barrel (unit)
CAPEX	Capital Expenditure
CT	Combustion Turbine
FEED	Front-End Engineering Design
FPT	Fluid Power Technology
HWDs	Hardwoods Power Plant
LECA	Lifetime Extension Condition Assessment
MW	Megawatt
NL Hydro	Newfoundland and Labrador
OEM	Original Equipment Manufacturer
SVL	Stephenville Power Plant

1. Introduction

Newfoundland and Labrador Hydro (NL Hydro) retained Hatch to perform a Life Extension Condition Assessment (LECA) and retirement optimization study for the Hardwoods (HWDs) and Stephenville (SVL) power plants. Both sites currently operate Rolls Royce Olympus C-type combustion turbines installed in the mid 1970's. This study has focused on these specific power plant assets within the fenceline of each power plant site and has not considered the wider system implications and costs of the retirement or replacement of these assets.

The Hardwoods facility has been in service since 1976 and includes a multi-shaft aeroderivative combustion turbine generator arrangement consisting of two (2) 25 MW Rolls Royce Olympus C-type 2022 combustion turbines, each with Curtiss Wright Power Turbines coupled to a common 63,341 kVA Brush Generator via SSS 208T clutches.

The Stephenville facility has been in service since 1975 and is comprised of the same configuration and combustion turbine models as Hardwoods with some differences in terms of the site layout, fuel storage and auxiliary balance of plant equipment.

This report includes a Class 5 CAPEX to replace the combustion turbine units capable of meeting the system capacity and synchronous condensing needs at each power plant location.

2. Replacement Combustion Turbine Generator Options Review

General Electric (GE), Siemens, Solar Turbines, and Mitsubishi Heavy Industries (MHI) were contacted to provide technical information on combustion turbine generator (CTG) units capable of meeting NL Hydro's functional, operational, and environmental requirements. The following sections summarize NL Hydro's key requirements, present the CTG options offered by each supplier, and identify the units selected as the basis for the replacement capital cost assessment.

2.1 Design and Performance Criteria for Replacement CTGs

The suppliers contacted during the study were requested to provide CTG offerings that meet NL Hydro's functional and operational requirements for the replacement of the Hardwoods and Stephenville CTG units.

The key requirements communicated to the suppliers are summarized as follows:

- **Technology and Capacity:** Aeroderivative or industrial-class combustion turbine solutions providing a total nominal capacity of approximately 50 MW, configured either as a single unit rated between 50 - 60 MW (1 × 100%) or two units each rated between 25 - 35 MW (2 × 50%).
- **Fuel Flexibility:** Primary operation on diesel fuel, with capability to operate on natural gas and qualified renewable fuels.
- **Synchronous Condenser Capability:** Ability to provide synchronous condenser operation through either a clutch mechanism or a free power turbine configuration.
- **Unit Configuration:** Single-ended design, consisting of one combustion turbine and one generator per unit.
- **Start-Up Performance:** Quick-start capability, with the ability to reach full load within 10 minutes.
- **Minimum Load Operation:** Capability to reliably operate at a minimum load of 5 MW.

2.2 Comparison of Aeroderivative vs. Industrial CTGs and Synchronous Condensing Considerations

Aeroderivative combustion turbines are derived from aircraft engine designs and feature distinct high-pressure and low-pressure turbine sections. Their design results in compact equipment footprints, high simple-cycle efficiency, rapid start capability, and strong load-following performance. Aeroderivative units also do not typically incur accelerated wear from frequent starts, making them well-suited for peaking, backup, and emergency operations. However, they generally have a higher capital cost on a $/MW basis, require more frequent maintenance and inspections based on operating hours, and are typically offered only in smaller unit ratings in a range of approximately 20 to 70 MW. A key advantage aeroderivative combustion turbines offer is that major overhauls can be completed quickly when a rotating-spares program is used, allowing the combustion turbine module to be swapped onsite and overhauled offsite. In recent years, aeroderivative units have experienced extended OEM lead times due to high global demand.

Industrial combustion turbines offer reduced maintenance frequency, improved delivery timelines, and unit sizes up to approximately 450 MW (in 60 Hz applications). They typically have lower simple-cycle efficiencies at ratings below 100 MW and heavier overall package weights, but their capital cost on a $/MW basis is generally lower than aeroderivative alternatives. Industrial combustion turbines are most commonly applied in base-load and combined-cycle service, though they remain viable for simple-cycle applications when annual start counts are expected to be modest. Hot gas path inspections (HGPIs) and major overhauls for industrial units are typically completed onsite, resulting in longer outage durations and making rotating-spares strategies less practical.

Synchronous condensing capability can be provided in combustion turbine generator packages by allowing the generator to remain synchronized to the grid and continue supplying inertia, reactive power, and voltage support after the combustion turbine engine is shutdown. In clutch-based synchronous condensing configurations, a mechanical clutch between the turbine and generator disengages the combustion turbine from the generator prior to shutdown. In free power turbine configurations, the generator remains coupled to the power turbine, which continues rotating after the shutdown of the combustion turbine engine section.

OEMs have advised that synchronous condensing operation without a clutch results in higher parasitic losses because the power turbine continues to rotate, with aerodynamic drag acting on the turbine blades inside the casing. These losses, combined with additional maintenance considerations, make non-clutched synchronous condensing operation unsuitable for regular or extended operation. Given the anticipated operating requirements of approximately 5,900 hours per year at Hardwoods and 3,800 hours per year at Stephenville, clutch-based synchronous condensing configurations are preferred for the replacement combustion turbine units.

2.3 CTG Options Summary

Suppliers provided information on a range of combustion turbine options, including both aeroderivative and industrial-class units, as well as configurations capable of supporting either clutched or free-power-turbine synchronous condensing operation. Table 2-1 and Table 2-2 below summarize the options offered. The inquiries sent to suppliers to request information and cost inputs to the project are provided in Appendix C.

Table 2-1: Aeroderivative Combustion Turbine Options

Vendor	GE		Siemens	MHI
Units	LM6000	LM2500XpressG4	SGT-A35	FT8 SwiftPac 30
Synchronous Condenser Mode	Clutched	Free Power Turbine	Not Offered, Potentially Available	Free Power Turbine
Power Output	53.9 MW	34.5 MW	31.3 – 33.4 MW(e)	30.1 MW
Start-Up Time	5 minutes	5 to 10 minutes	5 minutes	10 minutes
Gross Efficiency	40.8%	39.2%	37.8% - 40.4%	36.6% (Net)
Minimum Load	~4% (2 MW)	~6% (2 MW)	~3 to 6% (1 - 2 MW)	Not Provided
Minimum Load to Maintain Emissions Compliance	50%	50%	50%	Not Provided
Manufacturer Location	Evendale, OH, USA	Cincinnati, OH and Budapest, Hungary	Not Provided	USA
Footprint	67 ft (L) by 16 ft (W)	90 ft (L) by 34 ft (W)	59 ft (L) by 11 ft (W)	Not Provided

Note 1: “Not Provided” or “Not Offered” indicates that Vendors did not confirm data due to their internal workload constraints. Siemens advised that synchronous condensing capability for the SGT-A35 may be achievable using a clutched configuration, although this was not confirmed.

Note 2: Where vendors note a minimum emissions compliant load power plants are still typically permitted to operate at lower load ranges. The minimum emission compliant load typically applies to the standard applied to the project and a basis for reviewing stack testing results based on nominal power plant operation. If significant periods of low load operation are expected, the applicable higher emissions rates, however, would need to be considered in emissions modelling and the project air quality impact assessment.

Note 3: The power output capacities noted in the above table are based on catalogue data and performance at ideal conditions. The power output referenced in other sections of this report considers modeled performance at specific site conditions considering the impacts of ambient temperature, elevation and relative humidity.

Table 2-2: Industrial Combustion Turbine Options

Vendor	Siemens		Solar		MHI
Units	SGT800-50	SGT-600	T250	T350	H-25
Synchronous Condenser Mode	Not Offered, Potentially Available	Not Offered, Potentially Available	Clutched	Clutched	Clutched
Power Output	49.9 MW	24.5 MW(e)	22.1 MW	33.9 MW	41.0 MW
Start-Up Time	10 to 15 minutes	7 minutes	10 minutes	10 minutes	22 minutes
Gross Efficiency	39.4%	33.6%	38.1%	38.6%	36.2% (Net)
Minimum Load	~2 to 4% (1 - 2 MW)	~4 to 8% (1 - 2 MW)	10%	10%	Not Provided
Minimum Load to Maintain Emissions Compliance	50%	50%	50%	50%	Not Provided
Manufacturer Location	FinsPang, Sweden	FinsPang, Sweden	San Diego, California	Houston, Texas	Japan
Footprint	Not Provided	62 ft (L) by 15 ft (W)	55 ft (L) by 13 ft (W) excluding maintenance space	59 ft (L) x 13 ft (W) excluding maintenance space	Not Provided

Note 1: Information noted as “Not Provided” or “Not Offered” indicates information that was not provided or confirmed by Vendors due to their workload in responding to new project inquiries. With regard to the synchronous condensing capabilities of the SGT-800 and SGT-600 options, this capability may be available through equipping the unit for clutched operation although this was not confirmed by Siemens at the time of the inquiry.

Note 2: Where vendors note a minimum emissions compliant load power plants are still typically permitted to operate at lower load ranges. The minimum emission compliant load typically applies to the standard applied to the project and a basis for reviewing stack testing results based on nominal power plant operation. If significant periods of low load operation are expected, the applicable higher emissions rates, however, would need to be considered in emissions modelling and the project air quality impact assessment.

Note 3: The power output capacities noted in the above table are based on catalogue data and performance at ideal conditions. The power output referenced in other sections of this report considers modeled performance at specific site conditions considering the impacts of ambient temperature, elevation and relative humidity.

2.4 CTG Selection for Study Basis and CAPEX Development

The GE LM6000 and Solar Titan 350 were selected as the basis for the replacement cost study. These units were identified as the only options that:

- Support **clutched synchronous condensing** operation, which is required given the high annual synchronous condensing hours at Hardwoods (~5,900 hours/year) and Stephenville (~3,800 hours/year).
- Are capable of achieving near full load from a cold start within 10 minutes. This rapid start capability enables the power plant to respond swiftly to changes in grid demand or unexpected outages.
- Align with the desired single-unit (50 - 60 MW) or dual-unit (25 - 35 MW per unit) capacity ranges.

While the Solar Titan 350 currently supports only natural gas operation, Solar has indicated that diesel-fuel capability is expected by Q3 2028. Although not presently suitable for liquid-fuel operation, the Titan 350 was included in the study to show a viable dual-unit, clutched synchronous condensing configuration. Future suitability will depend on the successful commercialization and proven operation of liquid-fuel capability before project advancement.

It should be noted that the typical performance differences described earlier between aeroderivative and industrial turbines are not fully reflected in this comparison, as the Titan 350 exhibits higher efficiency than is generally characteristic for industrial-class units.

Based on the synchronous condensing requirements and the limitations of non-clutched configurations, the LM6000 and Titan 350 were the only offerings deemed suitable as the technical basis for the replacement capital cost assessment.

2.5 CTG Performance Summary

Two simple-cycle configuration cases were evaluated using GTPro which are summarized as follows:

- A single aeroderivative unit (1 × 50 MW) based on the GE LM6000 PC Sprint.
- A dual-unit industrial configuration (2 × 25 MW) based on the Solar Titan 350.

The GTPro performance results from the configuration cases are provided in Table 2-3.

Table 2-3: GTPro Performance Summary

Parameter	Units	GE LM6000 PC Sprint	Solar Turbine Titan 350
No. of Units	-	1	2
Load	%	100	100
Gross Power Output (see Note 1)	MW	50.4	69.3
Net Power Output (see Note 1)	MW	49.6	68.4
Net Efficiency	%	39.2%	38.4%

Note 1: The above performance is based on combustion turbine intake air conditions of 5.5 °C, 66 m above sea level, and 83% relative humidity. These performance values may differ from other ratings noted in catalogue data based on ideal conditions, or performance ratings at different site conditions.

The GTPro modelling results indicate that the GE LM6000 provides higher net efficiency at full load compared to the Solar Titan 350 units, although the dual-unit Titan 350 configuration provides higher total gross and net output. The Titan 350 results reflect natural-gas operation, as this model is not currently available with liquid-fuel capability. As noted previously, Solar has indicated that a diesel-fuel configuration is expected to be commercially available within the anticipated timeframe of the replacement project.

For minimum-load operation, both OEMs advised a 50% minimum load to maintain emissions-compliant operation. GE further noted that the LM6000 can operate down to 2 MW, although sustained operation at such low loads is not recommended. Solar advised that the Titan 350 can operate comfortably at 10% load, but with an associated increase in emissions at that condition.

3. Fuel Storage Review

The operating durations that could be supported by the existing diesel fuel storage capacities were calculated for the GE LM6000 and Solar Titan 350 combustion turbine options based on the GTPro model performance results. The following subsections summarize the estimated operating time that the existing on-site fuel storage tanks can support at 50%, 75%, and 100% load for each power plant location. The load considered in the calculation is based on the total generating capacity of each option, and therefore the Solar Titan 350 option considers a higher generating capacity.

3.1 Hardwoods Fuel Storage

The Hardwoods power plant is equipped with one (1) x 2,226,000 L diesel storage tank. The estimated operating durations that could be supported by the existing fuel storage capacity without fuel deliveries are summarized in Table 3-1. The calculations are based on a working capacity of 1,781,000 L (80% of the nominal tank capacity) which considers a typical working volume required for safe tank and fuel forwarding system operation.

Table 3-1: Hardwoods Estimated Diesel Fuel Storage Durations
(2,226,000 L storage capacity)

Load	GE LM6000 PC Sprint (1xUnit)	Solar Turbine Titan 350 (2xUnits)
50%	237 hours, 9.9 days	177 hours, 7.4 days
75%	179 hours, 7.5 days	129 hours, 5.4 days
100%	142 hours, 5.9 days	100 hours, 4.2 days

NL Hydro maintains a requirement of five (5) days of fuel storage at full-load operation for their existing combustion turbine generating stations. This is considered an appropriate minimum for backup generation applications, balancing reliability with the operational risks and costs associated with storing large volumes of fuel for assets with intermittent operating profiles.

Based on the existing storage capacity:

- The **1 × GE LM6000** configuration **meets** the 5-day requirement at 100% load.
- The **2 × Solar Titan 350** configuration **does not meet** the 5-day requirement, due to its higher combined output and lower efficiency relative to the LM6000.

To achieve a 5-day storage duration at 100% load for the 2 × Titan 350 option, an additional ~450,000 L of storage capacity would be required. Adding a second storage tank would also reduce plant-level availability impacts during tank inspections or maintenance, as the current single-tank configuration requires a complete plant shutdown for tank-related work.

However, the operational benefit may be insufficient to justify capital investment, given that:

- The shortfall from the 5-day requirement is relatively modest.
- The existing storage still provides a reasonable operating duration for backup generation service.

When both options are compared on a levelized 50 MW gross output basis, the 5-day fuel storage requirement can be met for either configuration.

3.2 Stephenville Fuel Storage

The Stephenville Power Plant is equipped with three (3) 477,000 L diesel storage tanks. The estimated operating durations that can be supported by the existing fuel storage capacity without fuel deliveries are summarized in Table 3-2. The calculations assume a total working capacity of 1,145,000 L (80% of the combined nominal tank capacity), which considers a typical working volume required for safe tank and fuel forwarding system operation.

Table 3-2: Stephenville Estimated Diesel Fuel Storage Durations (1,431,000 L storage capacity)

Load	GE LM6000 PC Sprint (1 x Unit)	Solar Turbine Titan 350 (2 x Units)
50%	152 hours, 6.4 days	114 hours, 4.8 days
75%	115 hours, 4.8 days	83 hours, 3.5 days
100%	91 hours, 3.8 days	65 hours, 2.7 days

NL Hydro maintains a requirement of five (5) days of fuel storage at full-load operation for their existing combustion turbine generating stations. This is considered an appropriate minimum for backup generation applications, balancing reliability with the operational risks and costs associated with storing large volumes of fuel for assets with intermittent operating profiles.

Based on the existing fuel storage capacity:

- The **1 × GE LM6000** configuration **does not meet** the 5-day requirement at 75% or 100% load.
- The **2 × Solar Titan 350** configuration **does not meet** the 5-day requirement ad 50%, 75% or 100% load.

To achieve five days of operation at nominal 100% load for either configuration, an estimated 1,272,000 L of additional storage would be required. This expansion could be achieved by installing three additional 477,000 L tanks, or by installing a smaller number of larger-capacity tanks.

When both options are compared on a levelized 50 MW gross output basis, the 5-day fuel storage requirement can only be met at 50% load.

4. CTG Location Assessment and Layout Development

Based on vendor data highlighted in Section 2.3, four (4) conceptual plot plan layouts were developed to illustrate representative arrangements for installing replacement CTG units at each site. For the aeroderivative configuration, the GE LM6000 was selected as the reference model as its power output aligns with the 50 MW requirement while also meeting the quick start and synchronous condensing capabilities identified in the study. The physical dimensions of the LM6000 package were used in developing the corresponding conceptual layouts.

For the industrial configuration, the Solar Titan T350 was selected as the reference model due to its ability to support clutched synchronous condensing operation. The physical dimensions of the T350 package were used in developing the corresponding conceptual layouts with an additional allowance to ensure sufficient space for maintenance activities, particularly for rotor removal.

The development of each conceptual layout considered a key requirement advised by NL Hydro to install and commission the new CTG units prior to decommissioning the existing units. Minimizing the interruption to the availability of both generating capacity and synchronous condensing capacity is a key project objective, and this can be accomplished by developing the new CTG units in a separate area of the project site. This approach will limit the interruption to the time required to tie into the fuel storage system and substation and disconnect the original units.

The conceptual layout for each project site is discussed in the following subsections. Existing NL Hydro drawings which have been used in the layout and concept development are listed in Appendix B. The conceptual layout development has also been supported by the following site visits attended by Hatch team members:

- HWD, April 22nd, 2025 attended by G. Cooper (Mechanical Engineer), A. Bursey (Electrical Engineer), M. Delaney (Structural EIT).
- SVL, May 6th, 2025 attended by S. DeYoung (Mechanical Engineer), A. Bursey (Electrical Engineer), M. Delaney (Structural EIT).
- HWD, May 7th, 2025 attended by G. Cooper (Mechanical Engineer), S. DeYoung (Mechanical Engineer), and A. Bursey (Electrical Engineer).

During the above site visits the Hatch team members completed a visual condition assessment of the existing facilities and assets, held discussions with NL Hydro personnel and collected information and photos to support the study. The site visits did not include any intrusive inspections or formal surveys. Information gathered during the site visits, and NL Hydro comments on earlier drawing versions has been used to support the replacement concept layout development through the completion of the replacement cost study which has been conducted from April 2025 to November 2025.

4.1 Hardwoods Replacement Concept

The proposed location options for the aeroderivative (1 x 50 MW) unit and the industrial (2 x 25 MW) gas turbine units at the HWDs site are shown in Appendix A.1 and A.2.

The following key aspects of the replacement project and existing power plant site have been considered in the layout concept development:

Site Area Selection: The area South-West of the existing power plant and substation site (Option 1), and the area South-West of the existing fuel tank (Option 2), have been identified as potential locations for the new power plant building and installation. The project site area has a number of constraints due to its proximity to the Trans-Canada Highway, the transmission line routing into the substation, neighbouring properties and water courses, and property boundaries with Newfoundland Power. Development in the Option 1 area would require engagement with Newfoundland Power who currently own this area of the switchyard, property boundary revisions, and the expansion of the site fence line area. The North-East area available within the site fence line was also reviewed as a potential development area, however, the space available, access requirements to existing Newfoundland Power facilities, and space requirements for decommissioning the existing combustion turbine unit were considered barriers to development in this area. A fence line expansion in the Option 1 area in the South-East direction would be required to increase the development area and space available within the layout. This would require approval to amend a road allowance and expand the property boundary.

While there would be limited available area within the site fence line for Option 1 for temporary construction facilities and laydown, there are areas South of the site near the fuel unloading area, and South-West of the fuel storage tank that could be explored for use for temporary construction facilities.

Combustion Turbine Generating Units, Control and Auxiliary Modules: The combustion turbine units, control modules and auxiliary module included in the layout are based on typical Vendor drawings based on the combustion turbine units considered as the study basis. The control building would house the combustion turbine generator control system, auxiliary motor control center, and 125 VDC batteries. The auxiliary modules would house auxiliary systems for lube oil, fuel delivery, and water delivery to emissions control. The units are shown in an enclosed building with a control room and operator facilities to follow best practices for cold climate installations.

Fuel Storage Unloading and Forwarding: The concept considers the re-use of the existing fuel storage tanks and unloading systems. The tie into the existing fuel storage and unloading systems includes a tie into the existing fuel forwarding line near to the North corner of the fuel storage tank containment berm. Option 1 would require a buried section for the new fuel forwarding pipeline to cross beneath an existing access road before running above ground parallel to the site fence line to connect to the new combustion turbine unit fuel forwarding systems. Should the replacement project pursue an expansion of the existing fuel storage capacity there is significant space available to the South-West of the existing fuel tank if Option 1 is pursued, or south of the fuel tank if Option 2 is pursued. The area South-West of the existing fuel tank previously housed a fuel tank that has since been decommissioned and removed. The former tank and containment location has since been reclaimed by vegetation and would need to be redeveloped.

Water Treatment: The demineralized water treatment plant and water storage tanks which are required to support emissions control systems and potential power augmentation systems are shown as an annex to the power plant building. The building annex and tank sizes have been scaled from reference projects. This area of the power plant would house the demineralized water trains and water pumps necessary for the demineralized water production process and water feed to the combustion turbine units. Water supply to the demineralized water treatment plant considers a new connection to the municipal water supply system.

Substation Connection: The concept to connect the new combustion turbine generating units to the substation includes an extension of the existing 66 kV bus bar, and installation of a new 13.8/66 kV transformer, switch gear and busduct. Development in this area may require coordination with Newfoundland Power on the relocation/reconfiguration of existing Newfoundland Power aerial lines in this area to ensure sufficient construction and operating clearances. To limit the potential impacts, the current layout has been arranged to avoid areas that would require the relocation of the existing Newfoundland Power assets.

4.2 Stephenville Replacement Concept

The proposed location for the aeroderivative (1 x 50 MW) unit and the industrial (2 x 25 MW) gas turbine units at the SVL site are shown in Appendix A.3 and A.4 respectively.

The following key aspects of the replacement project and existing power plant site have been considered in the layout concept development:

Site Area Selection: The North-East area of the existing power plant and substation site was selected for the new combustion turbine power plant building and equipment installation. This section of the existing site was found to offer the best combination of development space and clearance from the substation area and existing equipment. This area is assessed to provide the most available development space with only a minor expansion of the property area and fenceline required. While there would be limited available area within the site for temporary construction facilities and laydown there are areas South-West of the site that could be explored for use for temporary construction facilities.

Combustion Turbine Generating Units, Control, and Auxiliary Modules: The combustion turbine units, control modules and auxiliary modules included in the layout are based on typical Vendor drawings based on the combustion turbine units considered as the study basis. The control building would house the combustion turbine generator control system, auxiliary motor control center, and 125 VDC batteries. The auxiliary module would house auxiliary systems for lube oil, fuel delivery, and water delivery to emissions control. The units are shown in an enclosed building with a control room and operator facilities to follow best practices for cold climate installations.

Fuel Storage Unloading and Forwarding: The concept considers the re-use of the existing fuel storage tanks and unloading systems. The tie into the existing fuel storage and unloading systems includes a tie into the existing fuel forwarding line near to the North-West corner of the fuel storage tank containment berm. This would require a buried section for the new fuel forwarding pipeline to cross beneath an existing access road before running above ground parallel to the site fence line to connect to the new combustion turbine unit fuel forwarding systems. Should the replacement project pursue an expansion of the existing fuel storage capacity there is space available south of the existing fuel storage tanks which could be considered. Within the project fence line there appears to space for the development of at least one additional 477,000 L fuel storage tank in this area, however additional volume expansion may require an extension of the project fence line and approval for the adjustment of the property boundary.

Water Treatment: The demineralized water treatment plant and water storage tanks which are required to support emissions control systems and potential power augmentation systems are shown as an annex to the power plant building. The building annex and tank sizes have been scaled from reference projects. This area of the power plant would house the demineralized water trains and water pumps necessary for the demineralized water production process and water feed to the combustion turbine units. Water supply to the demineralized water treatment plant considers a new connection to the municipal water supply system.

Substation Connection: The concept to connect the new combustion turbine generating units to the substation includes an extension of the existing 66 kV bus bar, and installation of a new 13.8/66 kV transformer, switch gear and busduct.

5. Cost Estimate

For both the aeroderivative gas turbine (1 x 50 MW) and industrial gas turbine (2 x 25 MW) cases an Association for the Advancement of Cost Engineering (AACE) Class 5 cost estimate was developed, which carries an expected accuracy range of +30% to +100% and -20% to -50%. The estimates include all costs associated with the CTG replacement, covering the full scope from engineering and design to construction completion.

These estimates assume that only the following existing site assets will be reused to support operation of the new CTG units:

- Fuel Unloading System;
- Fuel Storage;
- Operator Facilities;
- Maintenance Buildings;
- Terminal Station;
- Back-up Generator;
- Stormwater Infrastructure;
- Site fencing, roads, access and parking areas.

The following new facilities and assets are included in the replacement cost estimates:

- Power Plant Building;
- Fuel Forwarding and Heating Systems;
- Demineralized Water Treatment;
- CTG Lube Oil System;
- CTG Cooling System;
- CTG Control Building;
- Generator Step-up Transformer;
- LV Electrical System and Motor Control Centers;
- Station Batteries and UPS.

These costs were estimated using Hatch's in-house data from previous similar projects, based on the number of units and their nominal capacities. These costs apply to completing a single replacement project at the either the Stephenville or Hardwoods project sites.

5.1 Aeroderivative Gas Turbine (1 x 50 MW) Cost Estimate

For the aeroderivative combustion turbine supply cost estimate, vendor budgetary pricing for the GE LM6000 was used. This unit meets the preferred characteristics identified through discussions with NL Hydro, including an aeroderivative design, clutched synchronous condenser capability, 10-minute quick start, and minimum load operation at 5 MW. While all options outlined in Section 2.3 are expected to be further considered during the future concept study, FEED study and tendering process, the LM6000 is the only evaluated unit that satisfies all criteria and is therefore used as the basis for this cost estimate.

The total project capital expenditures were calculated at approximately $256.3 million CAD (2025 $), with a detailed breakdown shown in Table 5-1. The estimated capital costs include direct costs, indirect costs, owner's costs and contingency. The decommissioning and removal of the existing combustion turbine units and their associated auxiliaries is excluded from the cost estimate.

Table 5-1: Aeroderivative Gas Turbine (1 x 50 MW) Cost Breakdown

WBS	WBS Name	Total Cost (CAD)
100	Site and Improvements	$1,718,000
200	Buildings, Structures and Foundations	$15,468,000
300	Power Generators and Auxiliaries	$91,299,000
400	Electrical Power Systems	$7,030,000
500	DCS & Instrumentation and Control	$1,774,000
600	Demineralized Water System	$2,400,000
700	Common Services Equipment and Systems (tie-in to the compressed air system, fire protection system, insulation, maintenance shop equipment, eye wash, etc.)	$3,412,000
800	Piping	$2,646,000
900	Contractor Indirects	$10,975,000
Total Direct Cost		**$136,722,000**
1000	EPCM (Engineering Support, Engineering Site Support, Commissioning Support, Project Management)	$20,264,000
1100	Freight	$9,027,000
1200	Spares	$2,814,000
1300	3rd Party Services	$318,000
1400	Vendor Representative	$1,261,000
1500	Other Indirect Costs (Heavy Hauls, Heavy Cranes, Scaffolding)	$3,555,000
1600	Temporary Facilities	$2,183,000
Total Indirect Cost		**$39,422,000**
1700	Contingency Factor (25% of Total Direct and Indirect Work)	$44,040,000
1800	Allowance for Project Risks (such as ground remediation work)	$2,000,000
Total Contingency		**$46,040,000**
1900	Owners Costs (8% of Total Direct and Indirect Work)	$14,090,000
2000	Interest during Construction (IDC)	$20,000,000
Total Owners' Costs		**$34,090,000**
	Grand Total (CAD)	**$256,274,000**

The above replacement cost estimate is based on a 2025 base year. Escalation may be applicable depending on the replacement project timing. Owner's Costs of 8% of total direct and indirect costs are based on NL Hydro input and are consistent with the Avalon CT project.

5.2 Industrial Gas Turbine (2 x 25 MW) Cost Estimate

For the industrial gas combustion turbine cost estimate, vendor budgetary pricing for the Solar Titan 350 was used. This unit aligns with the reference model used in the plot plan and performance modelling, however all options outlined in Section 2.3 are expected to be further considered during the future concept study, FEED study, and tendering process.

The total capital cost for the 2 x 25 MW configuration is estimated at $349.7 million CAD (2025 $), as detailed in Table 5-2. The estimated capital costs include direct costs, indirect costs, owner's costs and contingency. The decommissioning and removal of the existing combustion turbine units and their associated auxiliaries is excluded from the cost estimate.

Table 5-2: Industrial Gas Turbine (2 x25 MW) Cost Breakdown

WBS	WBS Name	Total Cost (CAD)
100	Site and Improvements	$1,843,000
200	Buildings, Structures and Foundations	$25,918,000
300	Power Generators and Auxiliaries	$121,476,000
400	Electrical Power Systems	$7,435,000
500	DCS & Instrumentation and Control	$3,547,000
600	Demineralized Water System	$2,400,000
700	Common Services Equipment and Systems (tie-in to the compressed air system, fire protection system, insulation, maintenance shop equipment, eye wash, etc.)	$3,412,000
800	Piping	$2,913,000
900	Contractor Indirects	$19,610,000
Total Direct Cost		**$188,554,000**
1000	EPCM (Engineering Support, Engineering Site Support, Commissioning Support, Project Management)	$27,917,000
1100	Freight	$12,276,000
1200	Spares	$3,719,000
1300	3rd Party Services	$426,000
1400	Vendor Representative	$1,693,000
1500	Other Indirect Costs (Heavy Hauls, Heavy Cranes, Scaffolding)	$4,902,000
1600	Temporary Facilities	$3,176,000
Total Indirect Cost		**$54,109,000**
1700	Contingency Factor (25% of Total Direct and Indirect Work)	$60,670,000
1800	Allowance for Project Risks (such as ground remediation work)	$2,000,000
Total Contingency		**$62,670,000**
1900	Owners Costs (8% of Total Direct and Indirect Work)	$19,410,000
2000	Interest during Construction (IDC)	$25,000,000
Total Owners' Costs		**$44,410,000**
	Grand Total (CAD)	**$349,743,000**

The above replacement cost estimate is based on a 2025 base year. Escalation may be applicable depending on the replacement project timing. Owner's Costs of 8% of total direct and indirect costs are based on NL Hydro input and are consistent with the Avalon CT project.

The higher cost is primarily due to the need for additional balance of plant components, such as extra piping tie-ins, foundations, and auxiliary systems. While the aeroderivative option is more cost-effective, the 2 x 25 MW configuration offers greater operational flexibility, particularly in managing variable load demands and maintaining partial availability during maintenance or outages.

5.3 Additional Cost Estimate Considerations for Future Fuel Supply and Storage Options

For the potential expansion of the fuel storage capacity and future conversion to operate on alternative fuels additional costs were estimated which would be additional to the above replacement option costs. These additional costs are summarized in the following sections.

5.3.1 Fuel Capacity Expansion

Expanding the fuel storage capacity at the power plant sites to support 5-days of nominal operation would require the development of additional storage tanks, a containment berm expansion and interconnecting piping and valving.

The estimated cost to expand the Hardwoods fuel storage facility by 450,000 L is $1.4 million CAD.

The estimated cost to expand the Stephenville fuel storage facility by 1,272,000 L is $2.5 million CAD.

5.3.2 Biofuel Conversion

Should the power plants be converted to biofuel operation in the future works may be required to complete interior tank coating upgrades and add heat tracing to the fuel piping distribution system depending on the properties of the selected biofuel at the time of conversion.

The estimated cost to convert the fuel storage system to biofuel operation is $1.0 million CAD.

5.3.3 Conversion to Hydrogen Operation (Excluding Delivery and Storage Infrastructure)

Should the power plants be converted to hydrogen operation or a hydrogen / natural gas blend fuel gas operation in the future, additional work would be required to implement a dual fuel and fuel gas operating capability on the combustion turbine generators.

Conversion costs to enable hydrogen operation are not available from Vendors on a specific model basis however engagement vendors indicate a potential cost on the order of $30 million CAD for field-based conversions. This cost does include fuel gas delivery and storage infrastructure.

6. Conclusions and Next Steps

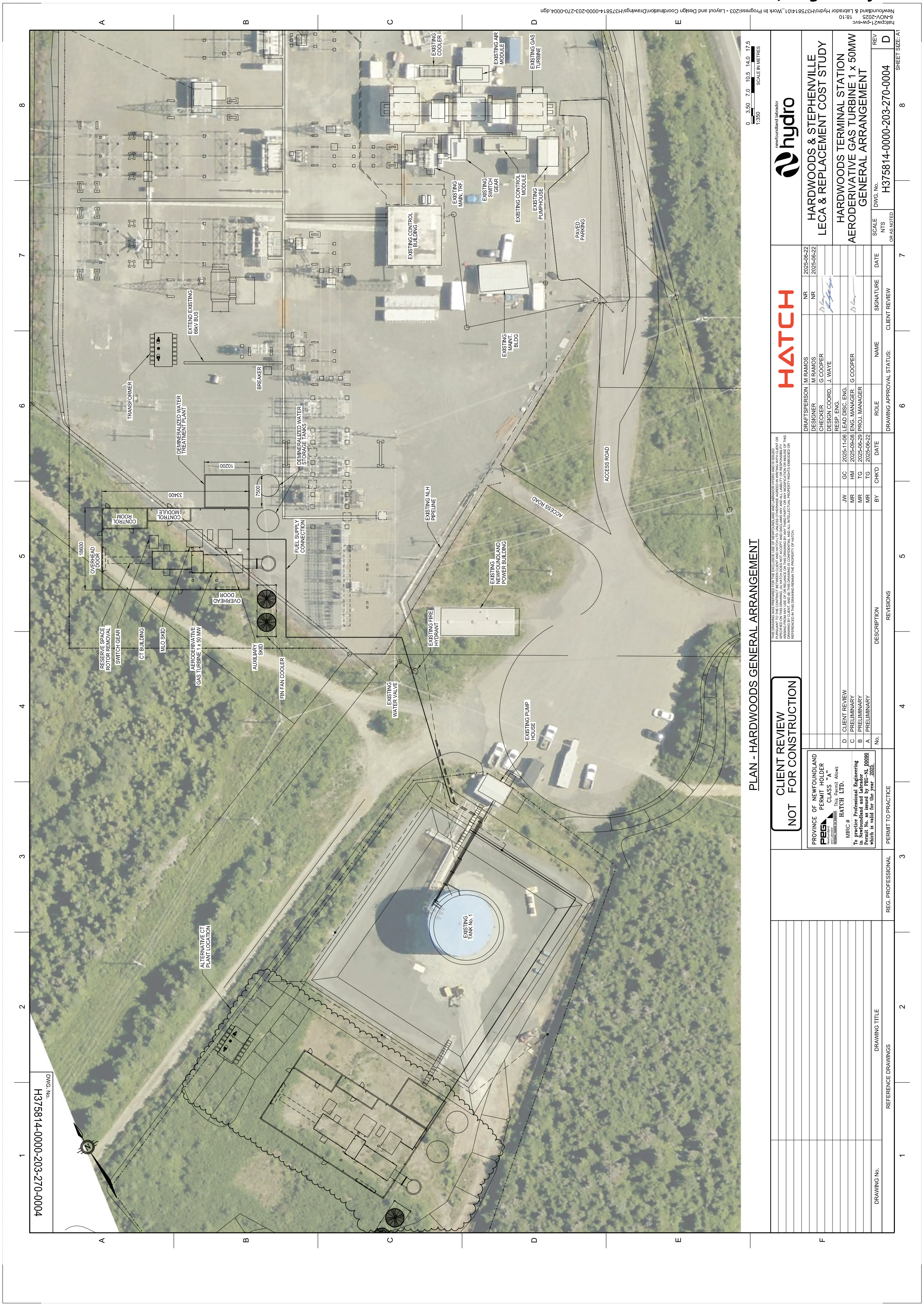
Based on the combustion turbine options offered, the GE LM6000 is the only unit identified that meets all of the preferred criteria for the Hardwoods and Stephenville power plant replacement concepts. The GE LM6000 is a 50 MW aeroderivative gas turbine, capable of operating in synchronous condensing mode using a clutch, with a 10-minute quick start and can achieve a minimum load capability of 5 MW.

When comparing the aeroderivative 1 x 50 MW option to the industrial 2 x 25 MW configuration, the aeroderivative option is more cost-effective at an estimated $256.3 million CAD versus $349.7 million CAD. This cost advantage is primarily due to the reduced number of units and associated balance of plant auxiliaries. However, the 2 x 25 MW configuration offers greater operational flexibility, particularly in managing variable load demands and maintaining partial availability during outages or maintenance.

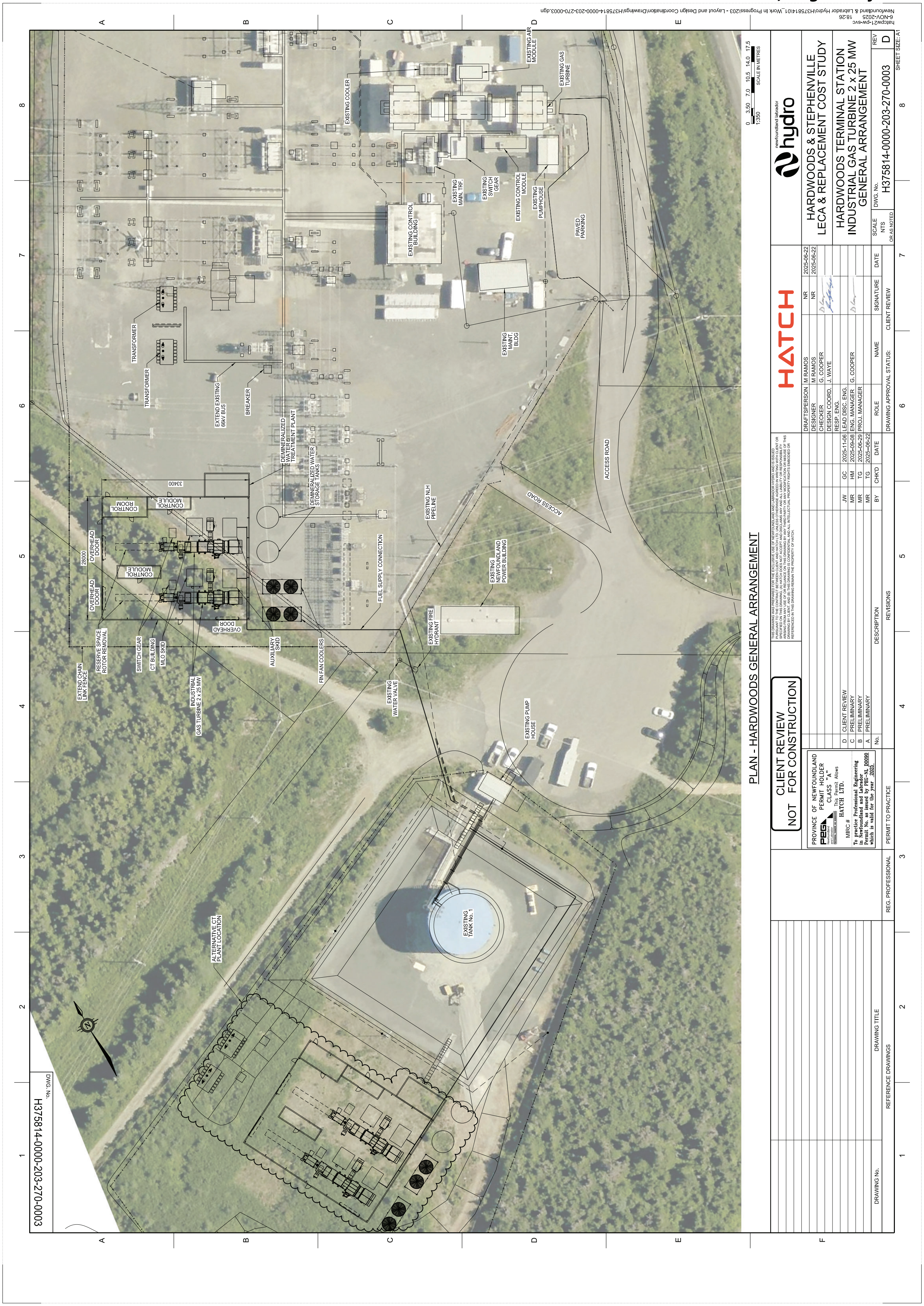
Should a decision be made to pursue the replacement of the combustion turbine units, Hatch recommends proceeding with a Concept Study to further define the concepts and develop an AACE Class 4 estimate including a Quantitative Risk Assessment (QRA) based on a Monte Carlo simulation, followed by a Front-End Engineering Design (FEED) Study to further define the project scope and support investment decisions. Completing a FEED Study will improve capital cost certainty and provide the necessary inputs for an AACE Class 3 cost estimate, with an expected accuracy of +10% to +30% and -10% to -20%. The specific CTG models recommended and used in this study are for basis of estimate purposes only and future model selection will depend on model availability at the time of project approval and during the CTG package tender process.

Appendix A:
Plot Plan Sketches

A.1 Hardwoods Generating Station, Aeroderivative Gas Turbine (1 x 50 MW)


PLAN - HARDWOODS GENERAL ARRANGEMENT
CLIENT REVIEW
NOT FOR CONSTRUCTION
HARDWOODS & STEPHENVILLE
LECA & REPLACEMENT COST STUDY
HARDWOODS TERMINAL STATION
AERODERIVATIVE GAS TURBINE 1 x 50MW
GENERAL ARRANGEMENT
H375814-0000-203-270-0004
newfoundland labrador hydro
HATCH
EXISTING CONTROL BUILDING
EXISTING MAIN. TRF.
EXISTING SWITCH GEAR
EXISTING CONTROL MODULE
EXISTING PUMPHOUSE
EXISTING GAS TURBINE
EXISTING AIR MODULE
EXISTING COOLER
PAVED PARKING
EXISTING MAINT. BLDG
ACCESS ROAD
EXISTING NLH PIPELINE
EXISTING NEWFOUNDLAND POWER BUILDING
EXISTING FIRE HYDRANT
EXISTING WATER VALVE
EXISTING PUMP HOUSE
EXISTING TANK No.1
ALTERNATIVE CT PLANT LOCATION
TRANSFORMER
EXTEND EXISTING 66kV BUS
BREAKER
DEMINERALIZED WATER TREATMENT PLANT
DEMINERALIZED WATER STORAGE TANKS
FUEL SUPPLY CONNECTION
CONTROL ROOM
CONTROL MODULE
OVERHEAD DOOR
RESERVE SPACE ROTOR REMOVAL
SWITCH GEAR
CT BUILDING
MLO SKID
AERODERIVATIVE GAS TURBINE 1 x 50 MW
AUXILIARY SKID
FIN FAN COOLER
D CLIENT REVIEW
C PRELIMINARY
B PRELIMINARY
A PRELIMINARY
DRAFTSPERSON M RAMOS
DESIGNER M RAMOS
CHECKER G COOPER
DESIGN COORD. J. WAYE
PROJ. MANAGER G COOPER
SCALE NTS
REV D
SHEET SIZE: A1

A.2 Hardwoods Generating Station, Industrial Gas Turbine (2 x 25 MW)



PLAN - HARDWOODS GENERAL ARRANGEMENT
EXISTING AIR MODULE
EXISTING GAS TURBINE
EXISTING COOLER
EXISTING MAIN. TRF.
EXISTING SWITCH GEAR
EXISTING CONTROL MODULE
EXISTING PUMPHOUSE
EXISTING CONTROL BUILDING
PAVED PARKING
EXISTING MAINT. BLDG
TRANSFORMER
TRANSFORMER
EXTEND EXISTING 66kV BUS
BREAKER
DEMINERALIZED WATER TREATMENT PLANT
DEMINERALIZED WATER STORAGE TANKS
ACCESS ROAD
ACCESS ROAD
EXISTING NLH PIPELINE
CONTROL ROOM
CONTROL MODULE
CONTROL MODULE
OVERHEAD DOOR
OVERHEAD DOOR
OVERHEAD DOOR
33400
28000
FUEL SUPPLY CONNECTION
EXISTING NEWFOUNDLAND POWER BUILDING
EXISTING FIRE HYDRANT
EXTEND CHAIN LINK FENCE
RESERVE SPACE ROTOR REMOVAL
SWITCH GEAR
CT BUILDING
MLO SKID
INDUSTRIAL GAS TURBINE 2 x 25 MW
AUXILIARY SKID
FIN FAN COOLERS
EXISTING WATER VALVE
EXISTING PUMP HOUSE
EXISTING TANK No. 1
ALTERNATIVE CT PLANT LOCATION
CLIENT REVIEW
NOT FOR CONSTRUCTION
HATCH
newfoundland labrador hydro
HARDWOODS & STEPHENVILLE LECA & REPLACEMENT COST STUDY
HARDWOODS TERMINAL STATION INDUSTRIAL GAS TURBINE 2 x 25 MW GENERAL ARRANGEMENT
DWG. No. H375814-0000-203-270-0003
REV D
SCALE NTS OR AS NOTED
D CLIENT REVIEW
C PRELIMINARY
B PRELIMINARY
A PRELIMINARY
DRAFTSPERSON M RAMOS
DESIGNER M RAMOS
CHECKER G. COOPER
DESIGN COORD. J. WAYE
PROJ. MANAGER G. COOPER
DRAWING APPROVAL STATUS: CLIENT REVIEW
PERMIT TO PRACTICE
REFERENCE DRAWINGS

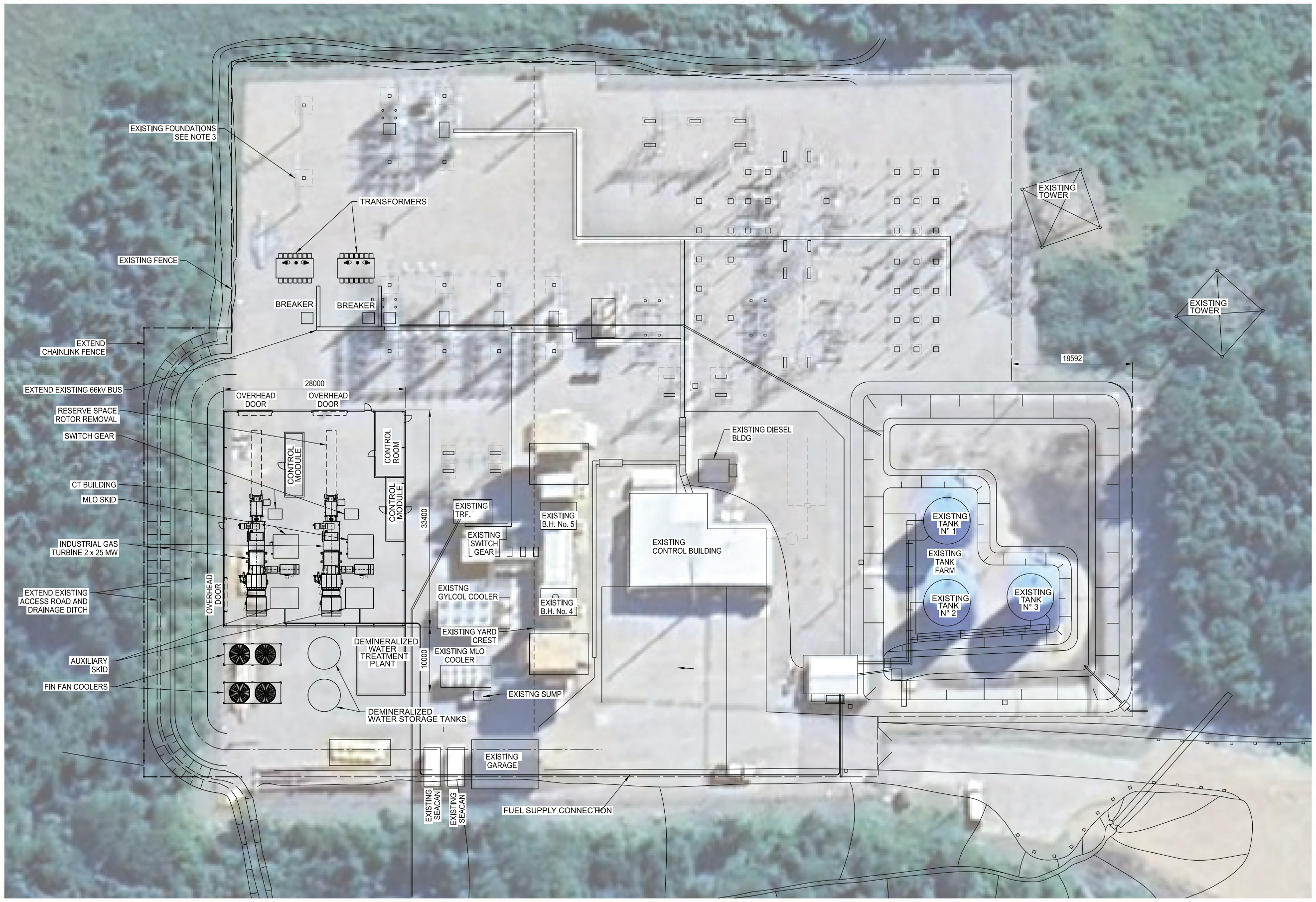
A.3 Stephenville Generating Station, Aeroderivative Gas Turbine (1 x 50 MW)


NOTES:
1. ALL DIMENSIONS ARE IN MILLIMETERS UNLESS OTHERWISE NOTED
2. 50 mm OF CLASS "A" EXISTING ROAD GRAVEL
3. EXISTING FOUNDATIONS FOR GANTRY, CIRCUIT BRAKERS, DISCONNECT SWITCHES, STEEL POLE
EXISTING TOWER
EXISTING TOWER
18592
EXISTING TANK N° 1
EXISTING TANK N° 2
EXISTING TANK N° 3
EXISTING TANK FARM
EXISTING DIESEL BLDG
EXISTING CONTROL BUILDING
EXISTING B.H. No. 5
EXISTING B.H. No. 4
EXISTING SUMP
EXISTING GARAGE
FUEL SUPPLY CONNECTION
EXISTING TRF
EXISTING SWITCH GEAR
EXISTING GYLCOL COOLER
EXISTING YARD CREST
EXISTING MLO COOLER
EXISTING SEACAN
EXISTING SEACAN
33400
10000
TRANSFORMER
BREAKER
CONTROL ROOM
CONTROL MODULE
18600
OVERHEAD DOOR
OVERHEAD DOOR
DEMINERALIZED WATER TREATMENT PLANT
DEMINERALIZED WATER STORAGE TANKS
EXISTING FENCE
EXISTING FOUNDATIONS SEE NOTE 3
EXTEND EXISTING 66kV BUS
RESERVE SPACE ROTOR REMOVAL
SWITCH GEAR
CT BUILDING
MLO SKID
AERODERIVATIVE GAS TURBINE 1 x 50 MW
EXTEND CHAINLINK FENCE
AUXILIARY SKID
FIN FAN COOLER
EXTEND EXISTING ACCESS ROAD AND DRAINAGE DITCH
PLAN - STEPHENVILLE GENERAL ARRANGEMENT
0 3.50 7.0 10.5 14.0 17.5
1:350
SCALE IN METRES
CLIENT REVIEW
NOT FOR CONSTRUCTION
PROVINCE OF NEWFOUNDLAND
PERMIT HOLDER
CLASS "A"
This Permit Allows
HATCH LTD.
To practice Professional Engineering in Newfoundland and Labrador Permit No. as issued by PEG-NL D0090 which is valid for the year 2025.
D CLIENT REVIEW JW GC 2025-11-06
C PRELIMINARY MR HM 2025-09-08
B PRELIMINARY MR TG 2025-06-29
A PRELIMINARY MR TG 2025-06-22
No. DESCRIPTION BY CHK'D DATE
REVISIONS
DRAFTSPERSON M RAMOS NR 2025-06-22
DESIGNER M RAMOS NR 2025-06-22
CHECKER G COOPER
DESIGN COORD. J WAYE
RESP. ENG.
LEAD DISC. ENG.
ENG. MANAGER G COOPER
PROJ. MANAGER
ROLE NAME SIGNATURE DATE
DRAWING APPROVAL STATUS: CLIENT REVIEW
HATCH
newfoundland labrador hydro
HARDWOODS & STEPHENVILLE LECA & REPLACEMENT COST STUDY
STEPHENVILLE TERMINAL STATION AERODERIVATIVE GAS TURBINE 1 x 50 MW GENERAL ARRANGEMENT
SCALE NTS
DWG. No. H375814-0000-203-270-0002
REV D
SHEET SIZE: A1
REG. PROFESSIONAL
PERMIT TO PRACTICE
DRAWING TITLE
REFERENCE DRAWINGS
DRAWING No.
DWG. No. H375814-0000-203-270-0002

A.4 Stephenville Generating Station, Industrial Gas Turbine (2 x 25 MW)

NOTES:

1. ALL DIMENSIONS ARE IN MILLIMETERS UNLESS OTHERWISE NOTED
2. 50 mm OF CLASS "A" EXISTING ROAD GRAVEL
3. EXISTING FOUNDATIONS FOR GANTRY, CIRCUIT BRAKERS, DISCONNECT SWITCHES, STEEL POLE



PLAN - STEPHENVILLE GENERAL ARRANGEMENT

0 3.50 7.0 10.5 14.0 17.5
1:350 SCALE IN METRES

CLIENT REVIEW
NOT FOR CONSTRUCTION

THIS DRAWING WAS PREPARED FOR THE EXCLUSIVE USE OF NEWFOUNDLAND AND LABRADOR HYDRO AND IS ISSUED PURSUANT TO THE CONTRACT BETWEEN CLIENT AND HATCH LTD. UNLESS OTHERWISE AGREED IN WRITING WITH CLIENT OR SPECIFIED ON THIS DRAWING, (A) HATCH DOES NOT ACCEPT AND DISCLAIMS ANY AND ALL LIABILITY OR RESPONSIBILITY ARISING FROM ANY USE OF OR RELIANCE ON THIS DRAWING BY ANY THIRD PARTY OR ANY MODIFICATION OR MISUSE OF THIS DRAWING BY CLIENT, AND (B) THIS DRAWING IS CONFIDENTIAL AND ALL INTELLECTUAL PROPERTY RIGHTS EMBODIED OR REFERENCED IN THIS DRAWING REMAIN THE PROPERTY OF HATCH.

HATCH

newfoundland labrador hydro

PROVINCE OF NEWFOUNDLAND PERMIT HOLDER CLASS "A"
This Permit Allows HATCH LTD.
MIRC #
To practice Professional Engineering in Newfoundland and Labrador Permit No. as issued by PEG-NL D0090 which is valid for the year 2025

No.	DESCRIPTION	BY	CHK'D	DATE
D	CLIENT REVIEW	JW	GC	2025-11-06
C	PRELIMINARY	MR	HM	2025-09-08
B	PRELIMINARY	MR	TG	2025-06-29
A	PRELIMINARY	MR	TG	2025-06-22

REVISIONS

ROLE	NAME	SIGNATURE	DATE
DRAFTSPERSON	M RAMOS	NR	2025-06-22
DESIGNER	M RAMOS	NR	2025-06-22
CHECKER	C. COOPER		
DESIGN COORD.	J. WAYE		
RESP. ENG.			
LEAD DISC. ENG.			
ENG. MANAGER	G COOPER		
PROJ. MANAGER			

DRAWING APPROVAL STATUS: CLIENT REVIEW

HARDWOODS & STEPHENVILLE
LECA & REPLACEMENT COST STUDY

STEPHENVILLE TERMINAL STATION
INDUSTRIAL GAS TURBINE 2 x 25 MW
GENERAL ARRANGEMENT

SCALE NTS OR AS NOTED | DWG. No. H375814-0000-203-270-0001 | REV D

SHEET SIZE: A1

DRAWING No. | DRAWING TITLE — REFERENCE DRAWINGS | REG. PROFESSIONAL | PERMIT TO PRACTICE

DWG. No. H375814-0000-203-270-0001

hatcpw21-pw-svc
6-NOV-2025 19:16
Newfoundland & Labrador Hydro\H375814\01_Work In Progress\203 - Layout and Design Coordination\Drawings\H375814-0000-203-270-0001.dgn

Appendix B

Reference Drawings

Document Register Index #	Drawing Number	Revision	Description
49	HWD-1	Date: October, 11, 2019, Revision No. 38	System Operating Diagram - HardwoodsTerminal Station
50	SVL-1	Date: September 9, 2018, Revision No. 20	System Operating Diagram - Stephenville Terminal Station
87	333-C-073.pdf	Date: December 12, 2000, Revision No. 4	Hardwoods Terminal Station and Gas Turbine Site Layout
90	319-C-001.pdf	Date: May 3, 1974, Revision No. N/A	Location Plan for Proposed Gas Turbine Installation Stephenville
91	319-C-003.pdf	Date: June 26, 1974, Revision No. N/A	Stephenville Gas Turbo Gen. Station Site Survey
92	319-C-004.pdf	Date: June 26, 1974, Revision No. N/A	Stephenville Gas Turbo Gen. Station Site Layout
93	319-C-005.pdf	Date: February 3, 1975, Revision No. 1	Stephenville Gas Turbo Gen. Station Site Layout & Transmission Line
94	319-C-008.pdf	Date: April 26, 2001, Revision No. 17	Stephenville Gas Turbo Gen. Station Site Layout

Appendix C

Combustion Turbine Supplier Inquiries

The following inquiry was sent to potential combustion turbine generator suppliers to request information on performance, dimensional data, lead time, and pricing to support the combustion turbine options review for the study, and to provide input to the replacement cost concept and estimate development:

From: MacLean, Hannah <hannah.maclean@hatch.com>
Sent: April 4, 2025 10:23 AM
To: [redacted]
Cc: DeYoung, Scot <scot.deyoung@hatch.com>
Subject: Request for Budgetary Pricing - Gas Turbine

Hi [redacted],

I am reaching out in hopes of obtaining budgetary quotes for a project I am working on, which involves replacing existing gas turbine units that have reached their end of life. The power plant is located in Eastern Canada, and has the following requirements:

- Two (2) 25-35 MW gas turbines
- Diesel fired gas turbines
- Gas turbine will operate mainly as a synchronous condenser

We are interesting in receiving information for both a free power turbine and a clutched machine option, as well as a double ended unit if available. Please provide the following information for all the gas turbine options which meet the above requirements:

- Budgetary cost
- Efficiency
- Cut sheets
- Lead time

Please provide a budgetary quote with the above information by April 11th, 2025.

Feel free to reach out to me if you have any questions.

Thanks,

Hannah MacLean (She/Her)
Thermal EIT

2699 Speakman Drive, Mississauga
Ontario Canada L5K 2R7

HATCH

Responses provided by the potential suppliers have been incorporated into the selection of combustion turbine generator models to be used for the purposes of the study, for the development of the 1x50 MW and 2x25 MW conceptual layout drawings, and the replacement cost estimates.